BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	**))))**	**Case No. ER-2016-0285**

MOTION FOR REHEARING OR RECONSIDERATION OF
MISSOURI INDUSTRIAL ENERGY CONSUMERS

Comes now, the Missouri Industrial Energy Consumers ("MIEC") and, for its Motion for Rehearing or Reconsideration, states as follows:

I. THE COMMISSION SHOULD ADOPT MR. BRUBAKER'S PROPOSED INTRA-CLASS RATE DESIGN FOR THE LPS AND LGS CLASSES

Although extensively briefed by the MIEC, the Report & Order does not discuss the LPS and LGS intra-class rate design proposed by Mr. Brubaker. To summarize, he proposes that the tail energy block rates of the LPS and LGS classes receive no rate increase, that the second energy block receive 75 percent of the system average increase, and that the first energy block and the demand and other charges of those classes receive increases such that the overall increases for each of those classes equal the system average increase.[1] Thus, his proposal has no impact on other classes but is designed solely to provide less intra-class inequity. As he notes in his testimony, customers buying power solely or mostly in the first block would still be subsidized by customers buying power in the second and tail blocks under his proposal, but the subsidies are lessened. The Commission should address and adopt his proposal.

[1] Exhibit 853, Brubaker Direct, p. 32, ll. 1 – 10.

No party disputed the following explanation Brubaker made of how the energy blocks in LPS and LGS work:

Q WHAT IS THE STRUCTURE OF THE ENERGY CHARGES?

A The energy charges are structured as three "hours use" blocks. The three blocks consist of the first 180 hours use of the billing demand, the next 180 hours use of the billing demand and the tail block is for consumption in excess of 360 hours use of the billing demand.

These are what are known as hours use, or load factor based charges. The rates decrease as the hours use increases to recognize the spreading of fixed costs over more kilowatthours as the number of hours use, or load factor, increases. This structure also recognizes that energy consumed in the high load factor block likely will be off-peak or at times when energy costs are lower than during on-peak periods.

Q PLEASE EXPLAIN HOW THE HOURS USE FUNCTION WORKS.

A The number of kWh to be billed in each hours use block is determined by the customer's billing demand and the amount of kWh purchased.

A customer operating basically a one-day shift (eight hours a day for five days a week) would have usage in the range of 180 kWh per kW of billing demand.[2] A customer operating two shifts likely would utilize approximately twice that much energy, and therefore use an additional 180 or so kWh per kW of demand, thereby filling up both the first and second blocks.

Thus, it is reasonable to consider the first block as being primarily the daytime on-peak hours, the second block for early morning, evening and/or weekend hours, and the third block for additional use in weekend and nighttime hours. Given these considerations, it is appropriate that the energy charges for the initial hours use blocks be higher than for the third hours use block in order to collect more fixed costs during the on-peak and shoulder periods.

Q CAN YOU ILLUSTRATE WITH AN EXAMPLE OF HOW THE RATE WORKS?

A Yes. Assume that a customer has a 1,000 kW billing demand, and uses 500,000 kWh in a month. This customer would be using 500 kWh per kW,[3] or 500 kWh for each kW of demand. To apply the rate, the 1,000 kW of demand would be multiplied by 180 kWh per kW, which is the size of the first block, and would result in 180,000 kWh being priced out at the first block. The customer would also fully utilize the second block, so 180,000 kWh would go in it as well and be priced at the second block rate.

[2] 8 hours/day x 5 days per week x 4.33 weeks per month = 173 hours.

[3] 500,000 ÷ 1,000 kW = 500 kWh/kW.

> The remaining 140,000 kWh[4] would be billed in the third, or high load factor, block.[5]

Brubaker then explained the charges for the energy tail blocks and how they are much higher than the variable cost to produce that power, which he opines should be the driver of charges for the tail blocks since the fair share of fixed charges are already collected from high load factor customers under the first block energy charges and other charges:

> Q **WHAT IS THE LEVEL OF THE ENERGY CHARGES FOR THE HIGH LOAD FACTOR (OVER 360 HOURS USE) BLOCK UNDER CURRENT TARIFFS?**
>
> A The charges vary slightly by voltage level and by season, but range from approximately 2.4¢/kWh to 2.6¢/kWh in LPS and from 3.5¢/kWh to 4.3¢/kWh for LGS.
>
> Q **DO YOU AGREE WITH THE LEVEL OF THE OFF-PEAK ENERGY CHARGES IN THE CURRENT TARIFFS?**
>
> A No, I do not. I believe the high load factor [intermediate and tail] block energy charges collect more fixed costs than is appropriate.
>
> Q **PLEASE EXPLAIN.**
>
> A I have analyzed KCPL's current rate case filing and its claims for costs. KCPL's calculated average variable costs (Schedule MEM-2, page 2) are 2.0-2.1¢/kWh. The energy charges in the high load factor block of KCPL's current LGS and LPS tariffs are considerably higher, as previously noted. Since KCPL proposes an essentially equal percentage increase to collect its requested revenue increase, these relationships would be perpetuated. Since the primary driver for this case is increased fixed costs, this equal percentage on the total rate is particularly inappropriate.
>
> Q **WHAT DO YOU CONCLUDE FROM THIS REVIEW?**
>
> A Based on the level of the average variable costs and also the avoided energy costs, it is clear that the off-peak energy charges are collecting more costs than appropriate.
>
> Q **WHAT SHOULD BE THE LEVEL OF THE OFF-PEAK ENERGY CHARGE?**
>
> A Recognizing that most of the fixed costs should be collected from use during the on-peak period and that consumption in the high load factor block occurs mostly during evening and weekend periods when KCPL's

[4] 500,000 - 180,000 - 180,000 = 140,000 kWh.
[5] Exhibit 853, Brubaker Direct, p. 29, l. 1 – p. 30, l. 9 (emphasis added).

> energy costs would be lower than they are during the on-peak periods, it is reasonable that the high load factor energy block be at a level approximating the utility's average variable costs.
>
> This structure would collect more costs through demand charges and provide better price signals to customers. It would also be a more equitable rate because it will charge high load factor and low load factor customers more appropriately. This structure also would improve the stability of KCPL's earnings. Because customer demands are generally more stable than their energy purchases, this rate design would make KCPL's revenue collection and earnings less volatile.[6]

In the above explanation, Brubaker uses the term "energy costs" to include the cost of fuel and minor O&M costs incurred to serve the intermediate and tail energy blocks since those costs are not fixed costs. It should also be noted that the variable costs at the time Brubaker filed his testimony, 2.0-2.1¢/kWh, were higher than they are today. As the Commission concluded in Finding 81, the updated base fuel cost is actually 1.545¢/kWh. Fuel costs are by far the largest component of the variable cost of energy. Now, KCPL and Staff have moved to modify the Report & Order to show that the base fuel cost is actually 1.542¢/kWh.[7] This shows that the tail block rates are significantly above the variable cost of producing the power in those tail energy blocks, and would continue to be so even without any increase in the energy charge in those tail energy blocks.

The only question that any party raised about the above analysis of Brubaker was Staff. Staff questioned Brubaker's conclusion that high load factor customers were consuming tail block energy off peak. Citing no facts or evidence, Staff stated that "[d]ifferent customers will have different load patterns. There is nothing to suggest that additional load that is billed out under the tail block occurs at "off peak" times, as opposed to daytime or evening times. This

[6] Exhibit 853, Brubaker Direct, p. 30, l. 10 – p. 31, l. 20 (emphasis added).
[7] *See* May 5, 2017 Joint Motion of KCPL and Staff to Modify Order.

would vary by customer."[8] But, citing facts that he included in his testimony, Brubaker established that Staff's unsupported conclusion was incorrect:

> **Q AT PAGE 9 OF HER REBUTTAL TESTIMONY, STAFF WITNESS SARAH KLIETHERMES DISAGREES WITH YOUR EXPLANATION OF HOW THE LOAD FACTOR BLOCKED RATES WORK AND YOUR STATEMENT THAT TAIL BLOCK ENERGY USE TENDS TO OCCUR OFF-PEAK. HOW DO YOU RESPOND?**
>
> A It generally is true that, just as a result of the ordinary nature of commerce, the higher load factor customers, particularly those who have significant usage in the tail block of the rate (load factor over 50%) tend to have their maximum demands during the day and purchase considerable amounts of energy during off-peak hours as well. The only way that a low load factor customer could have considerable usage during off-peak hours would be if the customer had its maximum demand at night. Certainly, there can be some customers like this, but it is unlikely that we would find many customers who were imposing their maximum demands on the utility system at night.
>
> **Q DO YOU HAVE ANY EVIDENCE TO SUPPORT THAT?**
>
> A Yes. I looked at KCPL's load research data and, for LGS and LPS, compared the class coincident peak (which occurs when the system has its peak – principally during the daytime) with the sum of the maximum demands of the individual customers in each class in order to determine the extent to which these maximum customer demands are correlated with class coincident peaks. Schedule MEB-COS-SR-1 shows these results.
>
> <u>A high ratio of class coincident peak to the sum of individual customer maximum demands indicates that the maximum customer demands are occurring near the times of the system coincident peaks. As an example, for the LPS schedule, note that the monthly ratios range from 69% to 88%, and average 83% for the year. This is a clear indication that, for the most part, maximum demands of customers are occurring during the hours when the utility system peaks, and not during night or weekend times. This adds further credence to the association of third block energy usage with off-peak times, and is additional support for my rate design recommendation.</u>[9]

Attached hereto is a true copy of MEB-COS-SR-1. It, along with the above testimony, demonstrates that the energy purchases in the tail blocks are highly correlated to off-peak. The tail block rates are designed to capture purchases made by high load factor customers (no

[8] Exhibit 212, Kliethermes Rebuttal, p. 9, ll. 8-12.
[9] Exhibit 855, Brubaker Surrebuttal, p. 10, l. 17 - p. 11, l. 21.

purchases at all are made under the tail block rate until a customer is almost at a fifty percent load factor). Furthermore, Brubaker has shown that there is a high correlation between class coincident peaks and system peaks, which means that much of the first block and some of the second block is priced during system peaks when a large majority of customers in that class have most of their demand. However, because these customers are high load factor customers, they continue to purchase similar quantities of energy during non-peak hours, resulting in usage priced in the tail block.

Staff also apparently would have used a different measure for the variable cost of energy. Rather than using KCPL's actual fuel and O&M expense to produce power that it sells to ratepayers, Staff would use the average wholesale market price of power in the SPP, which is about 2.3¢/kWh, slightly above Brubaker's 2.0-2.1¢/kWh.[10] As clearly explained in Brubaker's surrebuttal testimony, it is highly inappropriate to use the average wholesale market price of power because KCPL does not operate that way. It generates most of the power it uses to serve ratepayers and it is a net seller of power most of the time.[11] In any event, as Brubaker notes in his surrebuttal testimony, even if the average wholesale market price of power were used to measure the variable cost of energy, that price of 2.3¢/kWh is below the 2.4¢/kWh to 2.6¢/kWh in LPS and 3.5¢/kWh to 4.3¢/kWh for LGS tail energy blocks, and so would not militate against adoption of Brubaker's intra-class rate design.

In conclusion, Brubaker's intra-class rate design for the LPS and LGS classes should be adopted because: (1) that design is more equitable since it better reflects the costs to provide power in the various energy blocks of those two classes; (2) it accordingly sends more accurate pricing signals to ratepayers in those classes; and (3) it will provide more revenue certainty to

[10] Id., p. 7, ll. 1 – 7, p. 9, ll. 3 - 11.
[11] Id., p. 7, l. 8 – p. 10, l. 16.

KCPL since customer demands are generally more stable than their energy purchases. As mentioned above, this rate design has no impact on customers of other classes.

II. THE COMMISSION SHOULD REVISE CERTAIN OF ITS FACTUAL FINDINGS AS THEY ARE UNSUPPORTED BY THE RECORD

First, in Finding 134, the Commission found:

> The BIP method uniquely recognizes the tradeoffs that exist between the cost of installing a plant, the generation capabilities of a plant, and the cost of obtaining energy from that plant.

What the Commission appears to be saying here is that while some plants cost more to build, their variable cost of production (fuel and O&M costs) are lower while other plants cost less to build, their variable cost of production (fuel and O&M costs) are higher and that the BIP method gives meaning to these differences. The undisputed evidence in this case actually shows that the Staff BIP CCOS results do not bear that finding out. The Staff's BIP model allocates an above average share of the expensive, but low fuel cost, base load plants to high load factor customers such as industrial customers and a below average share of the expensive, but low fuel cost, base load plants to low load factor customers such as residential customers. To be consistent, and in keeping with this finding, one would expect that Staff's CCOS model would thus allocate a below average share of fuel costs to high load factor customers such as industrial customers and an above average share of the fuel costs to low load factor customers such as residential customers. But just the opposite is the case. Staff allocates above average fuel costs to the high load factor LPS customers and a <u>7.8 percent below average fuel cost to residential customers</u>.[12] This was just one of a myriad of reasons for rejecting Staff's BIP CCOS study, but even adopting the result notwithstanding so many reasons to reject it, the findings of the Commission must be supported by evidence, and this finding is not.

[12] Exhibit 854, Brubaker Rebuttal, p. 15, l. 19 - p. 16, l. 23.

Similarly, in Finding 135, the Commission found:

> Staff's detailed BIP method also considers the inverse relationship between the cost of capacity and the cost of energy produced by base, intermediate, and peaking units.

Staff’s execution of the BIP method created the anomaly, set forth above, that high load factor customers pay an above average share of capacity costs and also pay an above average share of fuel costs and low load factor customers pay a below average share of capacity costs and also pay a below average share of fuel costs. If Staff considered the inverse relationship, it did not consider it closely and did not feel compelled to implement it. This finding is simply not supported, and indeed contradicted, by the record.

Third, Finding 139 states:

> For purposes of evaluating the reasonableness of other parties’ study results, Staff has performed an Average and Excess (“A&E”) study using the A&E allocator for production capacity accounts and the sales at generation allocator for the production energy accounts. The results of the A&E study indicate no interclass shifts are necessary within the reasonable accuracy of the study, as opposed to the minimal interclass shifts indicated by the BIP study.

While this finding is technically correct, in that the results of the Staff’s A&E Study did show that no interclass shifts were warranted, the results of the Staff’s study were deeply flawed, as noted in MIEC’s initial and reply briefs. Simply, Staff grossly over-allocated distribution plant to industrial customers that either are not served by such plant or are minimally served.

III. THE COMMISSION SHOULD ADOPT BRUBAKER’S CCOS STUDY OR, GIVEN THE COMMISSION’S DECISION TO GRANT NO INTERCLASS RELIEF, ADOPT NO PARTICULAR CCOS STUDY AT ALL

The MIEC concurs in, and accordingly adopts, the arguments of the MECG made in its Motion for Rehearing in this matter on this issue.

Conclusion

For the reasons stated, the Commission should: (1) modify its Report & Order to address the key intra-class rate design proposal of Brubaker; (2) modify its Report & Order to adopt the CCOS results of Brubaker's A&E study or simply adopt no particular CCOS study since it has reached the conclusion that no interclass shifts are in order anyway; and (3) modify its Report & Order to remove factual findings that are contrary to the record.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I do hereby certify that a true and correct copy of the foregoing document has been emailed this 12th day of May 2017, to all counsel of record.

*/s/ Edward F. Downey*______

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KANSAS CITY POWER & LIGHT COMPANY
Case No. ER-2016-0285

Load Research Coincident Peak (CP) and
Maximum Diversified Demand (MDD)
of Customers

		LGS			LPS		
		CP	MDD		CP	MDD	
Line	Month	(MW)	(MW)	Ratio	(MW)	(MW)	Ratio
		(1)	(2)	(3)	(4)	(5)	(6)
1	January	345	484	71%	227	287	79%
2	February	378	484	78%	244	290	84%
3	March	347	484	72%	233	299	78%
4	April	298	418	71%	254	300	85%
5	May	285	413	69%	261	308	85%
6	June	327	443	74%	291	336	87%
7	July	360	482	75%	303	347	87%
8	August	368	462	80%	301	342	88%
9	September	362	462	78%	298	338	88%
10	October	321	434	74%	270	313	86%
11	November	292	431	68%	237	302	78%
12	December	291	427	68%	199	289	69%
13	Total	3,974	5,423	73%	3,117	3,748	83%

Note:
(1) CP is the demand of all customers on the rate at the time of the KCPL monthly peak.
(2) MDD is the summation of the maximum demands of all of the customers on the rate.

Source: KCPL Allocators MO Rev 6-17-16 Avg & Pk 4 CP.xls