BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	File No. ER-2016-0285

INITIAL POST-HEARING BRIEF OF THE UNITED STATES DEPARTMENT OF ENERGY AND FEDERAL EXECUTIVE AGENCIES

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COMES NOW the United States Department of Energy ("DOE" or "the Department") and the Federal Executive Agencies ("FEA"), collectively referred to as DOE/FEA, by and through counsel, and for their Initial Brief in the above-captioned proceeding, state as follows:

INTRODUCTION

The U.S. Department of Energy has been delegated authority by the U.S. General Services Administration ("GSA") to intervene in Kansas City Power & Light ("KCP&L" or "the Company") electric rate cases in Missouri on behalf of FEA facilities taking service from KCP&L. 40 U.S.C. §501. Large federal facilities taking service from KCP&L in Missouri include the Richard Bolling Federal Complex and Whitaker Courthouse located in downtown Kansas City, Missouri, and the Bannister Federal Complex located south of the Metropolitan area.

The Department adheres to the principle that electric rates should be reasonable and cost based so that rates send accurate price signals to customers, promote efficient electricity use and electrical equipment investment, and avoid inter- and intra-class subsidy problems. Interclass subsidies produce inefficiencies; and while some level of interclass subsidy is often unavoidable, the record in this case demonstrates that cost allocation has moved far away from costs.[1] Adoption of DOE/FEA's recommended Four Coincident Peak ("4CP") cost allocation methodology, coupled with gradualism, will begin to move rates towards cost of service. In addition, large customer intra-class rate adjustments should be avoided in this case. The Commission has not been presented with enough information to assign costs intra-class to the LPS and LGS rate classes and should avoid doing so until such information is available.

[1] See DOE Ex. 502, Rebuttal Testimony of Michael R. Schmidt, at 3:3-7.

STATEMENT OF THE ISSUES AND RECOMMENDATION

This brief addresses which cost allocation methodology the Commission should adopt for KCP&L. In this case, parties proposed four different cost allocation methodologies to allocate KCP&L's demand-related production costs to the various rate classes – Residential, Small General Service, Medium General Service, Large General Service, Large Power Service and Lighting. KCP&L proposed to utilize the Average & Peak Production Plant Allocation method ("Average and Peak" or "A&P") to allocate costs to these customer classes.[2] DOE/FEA utilized the 4CP method.[3] The Missouri Industrial Energy Consumers ("MIEC") utilized the Average and Excess – 4 Non-Coincident Peak method ("A&E-4NCP" or "A&E").[4] Finally, Staff utilized the Detailed Base, Intermediate, and Peak ("BIP") method.[5]

DOE/FEA recommends adoption of the 4CP method to allocate production costs to the rate classes because it represents the most logical cost allocation methodology for KCP&L. This is because it recognizes (1) public utilities build and acquire capacity to reliably meet their peak demand; (2) the Residential class, as demonstrated by three of the four cost studies submitted in this case, has been and continues to be heavily-subsidized by the other rate classes; (3) for a summer-peaking utility such as KCP&L, cost allocation should be predicated upon peak demand rather than annual energy usage; and (4) as a member of the Southwest Power Pool ("SPP") and a participant in SPP's Integrated Marketplace ("SPP-IM"), KCP&L has no control over which hours of the year its plants get dispatched or the locations of the loads KCP&L's generation plants are dispatched to serve. As supported by the arguments in this brief, DOE/FEA

[2] See KCP&L Ex. 136, Direct Testimony of Marisol Miller at 10:9-11.

[3] See DOE Ex. 501, Corrected Direct Testimony of Michael R. Schmidt at 9:4-18.

[4] See MIEC Ex. 853, Direct Testimony of Maurice Brubaker at 3:4-7.

[5] See Staff Ex. 202, Staff's Rate Design and Class Cost-of-Service Report at 6:2-3.

recommends that the Commission adopt the 4CP cost allocation methodology to allocate KCP&L's demand-related production costs to the various customer rate classes.

All parties in this case agree the basic premise of cost allocation is to align revenue responsibility with cost causation.[6] The basic procedure for conducting a CCOSS is to identify the different types of costs ("functionalization"), determine their primary causative factors ("classification"), and then apportion each item of cost among the various rate classes ("allocation").[7] Adding up the individual pieces gives the total cost for each customer class.[8]

The disagreement in this case regarding the four methodologies for allocating production plant costs to the rate classes concerns which methodologies are well-regarded in the industry and supported by the record evidence; representative of the reality of KCP&L's operations and participation in an organized wholesale electricity market; and consequently, which methodology will address interclass subsidies and begin to align the Company's rates with the costs to serve each customer class. DOE/FEA argues that the 4CP and A&E methods are both reasonable cost allocation methodologies; and DOE/FEA recommends that the Commission adopt the 4CP methodology proposed by Dr. Schmidt.

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[6] MIEC witness Mr. Brubaker states that the objective of cost allocation is to determine what proportion of the utility's total revenue requirement should be recovered from each customer class; and also that class cost of service studies ("CCOSS") are performed to determine the portions of the total costs that are incurred to serve each customer class. See MIEC Ex. 853 at 3:25-28. ("The cost of service study identifies the cost responsibility of the class and provides the foundation for revenue allocation and rate design.") Id. at 3, ll. 28-30; Staff states that a CCOSS study allocates and/or assigns the utility's total cost of providing electric service to all the customer classes in a manner reasonably reflecting cost causation. See Staff Ex. 202 at 6:10-11; DOE/FEA witness Dr. Schmidt states that results from a Commission-approved CCOSS should be a principle guide in setting the revenue requirement and rates (prices) for each customer class in a general rate case. See DOE Ex. 501 at 9:18-20. Dr. Schmidt further states that cost-based pricing identifies the overall fixed, variable, and indirect costs of production and transmission and prices those products accordingly. Id., ll. 20-22.

[7] See MIEC Ex. 853 at 8:6-9.

[8] Id. at 9:10-11.

The Company's proposed A&P method and, to a greater extent, Staff's detailed BIP method, are the wrong cost allocation methodologies to apply in KCP&L's service territory. The A&P method fails to comport with cost causation principles by inappropriately allocating a large percentage of production plant costs on the basis of average energy use rather than peak use; and more egregiously, adoption of the BIP methodology, for a variety of reasons discussed below, would produce rates that are not just and reasonable in violation of Missouri law.[9]

Regarding the allocation of transmission plant costs, DOE/FEA and MIEC used the same allocation methods each used for allocating production costs, or the 4CP and A&E methods, respectively. As both DOE/FEA witness Dr. Schmidt and MIEC witness Brubaker explain, KCP&L incurs production and transmission costs to meet the peak demand placed on its system,[10] and "if a utility has a high summer peak relative to the demands in other seasons, then production and transmission capacity costs should be allocated relative to each customer classes contribution to summer peak demands."[11] The Company allocated demand-related transmission costs to the rate classes using the same A&P method that it used to allocate demand-related production costs, thereby inappropriately perpetuating an emphasis on energy consumption as the cost driver for demand-related costs.[12] Staff allocated demand-related transmission to the rate classes using the 12 Coincident Peak ("12CP") method, which deemphasizes the importance of KCP&L's summer peak demands in determining KCP&L's demand-related transmission costs.[13] The 4CP and A&E methods are both reasonable methods for allocating demand-related

[9] Mo. Ann. Stat. § 393.150.

[10] See DOE Ex. 501 at 5:6-7.

[11] See MIEC Ex. 853 at 16:20-22.

[12] See KCP&L Ex. 136 at 7:15-16.

[13] See Staff Ex. 202 at 21-22.

transmission costs; and DOE/FEA recommends that the Commission adopt Dr. Schmidt's proposed 4CP methodology.[14]

In addition, consistent with principles of gradualism, DOE/FEA urges the Commission to cap rate increases for any particular rate class at the greater of one-third (33%) more than the system average percentage rate increase or 3% above the system average percentage rate increase. Class rate changes below the system average should be limited to double these levels (i.e., the lesser of two-thirds less than the system average percentage rate increase or 6% below the system average rate increase), prior to any reallocation of revenues necessitated by the proposed caps on rate increases.[15] This will ensure that no rate class experiences rate shock.

Finally, Mr. Brubaker's intra-class rate proposal for the Large Power Service ("LPS") and Large Generator Service ("LGS") classes - in which he recommends a 75% cap on any increase to the middle block energy rate, no change to the tail block energy rate, and all other new revenues required from the LPS and LGS classes be recovered from the first block energy rate, demand and customer charges - is premature and should be rejected until KCP&L can determine the reasonableness of that proposal and the equity of its effects on the customers within these rate classes.[16] Rather, as Mr. Brubaker himself states, the Company should examine the tariff schedules and attempt to move the rate elements closer to cost of service.[17] The Commission has adopted an intra-class rate structure consistent with Mr. Brubaker's proposal in

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[14] Because the allocation of transmission costs is of somewhat less significance than the allocation of production costs (see KCPL Ex. 136 at 9:17-18, "Production plant is the single, largest component cost to allocate to the classes within the study"), this brief does not focus additional attention on transmission cost allocation.

[15] See DOE Ex. 501 at 5-6.

[16] See MIEC Ex. 853 at 33:3-7 and Schedules MED-COS-7 and MEB-COS-8.

[17] See id at 33:12-14.

the past as a stipulated agreement among the parties. But the agreements have not been based upon any analysis or record evidence. Similarly, there is simply not enough evidence before the Commission to determine which blocks within the LGS and LPS rate classes are responsible for various amounts of fixed costs. Thus, the Commission should adopt an equal percentage increase or decrease for the LGS and LPS classes until such time as the Company provides a study upon which to base intra-class rate design decisions.

DESCRIPTION OF THE PROPOSED COST ALLOCATION METHODOLOGIES AND THEIR RESULTS

A. The 4CP Methodology

DOE/FEA propose adoption of the 4CP cost allocation methodology. Demand-related production and transmission costs are the fixed costs associated with a company's production and transmission plant and are incurred regardless of electricity sales to customers.[18] Production and transmission capacity is built (or acquired) to meet system peak demands (plus reserves) – not average demands.[19] This is because no utility would want to find itself in a situation where it had insufficient capacity to serve its load. Once capacity is built to meet system peaks, its fixed (sunk) costs do not change based on the intensity of its use – therefore the allocation of those fixed costs must be linked to peak demands that the capacity was built to serve.[20] KCP&L is a summer-peaking utility, experiencing its maximum system peak demand sometime during the summer months of June, July, August or September.[21] The 4CP is the most appropriate cost

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[18] See DOE Ex. 501 at 6:11-13. Examples of these fixed costs include return on production and transmission rate base, depreciation, fixed operating and maintenance expenses, and property taxes. Id. at 6, ll. 13-15.

[19] See id at 9:7-8.

[20] See id at 9:9-12.

[21] See id at 15, Figure 4.

allocation method because it utilizes the coincident peak demands for each rate class that occur during those four months to calculate each rate class' relative share of KCP&L's system peak during those months.[22] As MIEC argues, KCP&L's load pattern has predominant summer peaks which means these demands should be the primary ones used in the allocation of generation and transmission costs; demand in other months are of much less significance, do not compel the addition of generation capacity to serve them and should not be used in determining allocation of costs.[23]

Dr. Schmidt ran KCP&L's CCOSS model using the 4CP methodology to allocate demand-related production and transmission costs to Missouri retail rate classes and it confirmed that residential customers are being subsidized by non-residential customers.[24] Table 1 in Dr. Schmidt's Corrected Direct Testimony includes a relative Rate of Return Index which reveals that all customer classes are over-contributing to the Company's revenue requirement (the Lighting Class is over-contributing by an overwhelming margin) except for the Residential class which is significantly under-contributing to the Company's revenue requirement.[25] Table 2 depicts the changes in revenue required within each customer class to move retail class revenues to cost-based levels at the Company's proposed revenue requirement, utilizing the 4CP method to allocate demand-related production and transmission costs. Table 2 indicates a 29.4% increase in revenue allocations to the Residential class, a 35.7% decrease in revenue allocations

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[22] See DOE Ex. 501 at 9:14-16. The resulting percentages for each rate class are then multiplied by the demand-related or fixed production and transmission costs to allocate those costs to the rate classes. See id, ll. 16-18.

[23] See MIEC Ex. 853 at 17:5-9.

[24] See DOE Ex. 501 at 10:3-4.

[25] See id, Table 1.

to the Lighting class and revenue allocation shifts within 4% to all other customer classes are required to bring rates in line with cost of service at the Company's initially-proposed revenue requirement.[26]

However, Dr. Schmidt supports a gradual move to cost-based rates to avoid rate shock. His gradualism proposal (discussed above) under KCP&L's initially-proposed revenue increase of $90.1 million yields rate increases of 14.4% to the Residential class, 6.8% to the Lighting class and 8-9% for all other customer classes.[27] Dr. Schmidt also provides Tables depicting illustrative revenue allocation shifts at 75%, 50% and 25% of the Company's revenue increase request (inclusive of his gradualism proposal) in case the Commission does not grant KCP&L its full request.[28] For example, if the Commission were to award KCP&L a revenue increase at 25% of its request ($22.5 million), the impact on the Residential class would be a modest 5.7% increase using Dr. Schmidt's 4CP method and gradualism approach.[29] Dr. Schmidt also notes that a relatively small increase or decrease granted to KCP&L in this case presents a unique opportunity to move class revenue allocations toward cost of service without the burden of a significant revenue requirement increase on customers.[30]

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[26] See id at 12, Table 2.

[27] See id at 14, Table 3.

[28] See id at 14-16, Tables 4, 5, and 6. DOE/FEA did not sponsor testimony on the issue of revenue requirement in this case and does not take a position on the appropriate revenue increase or decrease the Commission should award the Company here. However, given the revenue positions of intervening parties, Dr. Schmidt provided Tables 4, 5 and 6 for illustrative purposes.

[29] See id at 16, Table 6.

[30] See DOE Ex. 502 at 3:20-22. Lower overall revenue requirement percentage increases combined with DOE/FEA's gradualism proposal ease the burden on any rate class of moving rates toward cost of service. Mr. Brubaker also indicates that the smaller the overall increase granted to KCPL, the larger the movement toward cost of service can be. See MIEC Ex. 853 at 27:17-19.

B. The Average and Excess Methodology

The A&E methodology incorporates a consideration of both the maximum rate of use (demand) and the duration of use (energy). Each class' "average" demand is the total kWh usage divided by the total number of hours in the year. This is the amount of capacity that would be required to produce the energy if it were taken at the same demand rate each hour. Each class' "excess" demand is the difference between each class' non-coincident peak demand in the four summer months and each class' average demand.[31]

The average demand is allocated to classes in proportion to their average demand (energy use). The difference between the average demand and the excess demand is then allocated to customer classes on the basis of a measure that represents their contribution to the "peaking" or variability in usage.[32] According to Mr. Brubaker, the excess component of the A&E method is an attempt to allocate the additional capacity requirements of the system (measured by the system excess) in proportion to the "peakiness" of the customer classes (measured by the class excess demands).[33]

MIEC recommends adoption of the A&E cost allocation method to allocate demand-related production and transmission costs because it considers the maximum class demands during the critical time periods, and is less susceptible to variations in the absolute hour in which peaks occur – producing a somewhat more stable result over time.[34] The results of MIEC's proposed CCOSS is depicted in Schedule MEB-COS-4 attached to MIEC witness Mr.

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[31] See MIEC Ex. 853 at 17:17 – 18:2.

[32] See id at 18, ll. 3-7 (citing the NARUC Electric Utility Cost Allocation Manual (1992) at 81).

[33] See id at 19:6-9.

[34] See id at 19:21-24.

Brubaker's Direct Testimony. It shows that under the A&E cost allocation method, movement of all classes to cost of service will require a revenue increase to the Residential class and a decrease to all other classes.[35] On Schedule MEB-COS-5, Mr. Brubaker demonstrates that under the A&E cost allocation method, the Residential class would require an increase of about $58 million, or 14.8%, in order for the class to move to cost of service at the Company's initially-proposed revenue requirement. Conversely, all other rate classes would require between a 6%-12.5% rate decrease to move to cost of service, with the LPS class receiving a 7.4% revenue allocation reduction.[36]

Adhering to principles of gradualism, Mr. Brubaker proposes a revenue allocation adjustment range between 25% and 50% in the direction of cost of service and he states a movement in this range would not be unreasonable.[37] Such an adjustment would limit a Residential class revenue-neutral increase to between 3.7% and 7.4% (as compared to the 14.8% increase required to move all the way to cost of service under the A&E method).

C. The Average & Peak Method

Company witness Marisol Miller considered all cost allocation methods and selected the Energy Weighted approach, specifically the A&P Production Plant Allocation method.[38] According to Ms. Miller, the A&P method is an energy-weighted method of production plant allocation that gives classes recognition for both usage and contribution to peak load.[39] The Company also proposed using the A&P method for allocating demand-related transmission costs.

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[35] See id at 26:4-6 and Schedule MED-COS-4:0400.

[36] See id at 26:9-19 and Schedule MED-COS-5.

[37] See id at 27 and Schedule MEB-COS-6 at 1-2.

[38] See KCP&L Ex. 136 at 10:5-11.

[39] See id at 13-15.

In using the A&P method, the majority of demand-related production costs, as determined by KCP&L's system load factor, are allocated on the basis of class average energy usage, and the remaining minority of those costs are allocated using a 4CP method.

The Company's CCOSS resulted in a rate of return ("ROR") of 5.5% and indicated that the residential (4.0%) and large power service ("LPS") customers (4.9%) fell below this contribution level, while all other customer classes over-contributed.[40] According to the Company, to achieve the initially-proposed revenue increase of 10.8%, the Residential class requires a 20% increase to its revenue requirement, LPS requires a 14.2% increase and the other classes are within 3.5% of their required revenue requirements (except for the Lighting class which would require a 6.8% decrease to its revenue requirement).[41]

D. <u>The Base, Intermediate, Peak Method</u>

Staff states that the detailed BIP method takes into consideration the differences in the capacity costs associated with units that run at a stable level much of the year, versus the capacity costs associated with units that quickly dispatch only a few hours a year, as well as those intermediate units that have cost and operation characteristics in between those two extremes.[42] The BIP method also considers "the inverse relationship between the cost of capacity and the cost of energy produced by base, intermediate, and peaking units"[43] - that is, base plants tend to be more expensive to install, but have a lower average cost of energy, while peak plants tend to be less expensive to install but have a high average cost of energy, and

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[40] See id at 14:9.

[41] See id at 14:13.

[42] See Staff Ex. 202 at 9:1-4.

[43] See id at 9:4-6.

intermediate plants tend to be somewhere in between the two.[44] According to Staff, the capital costs of KCP&L's generation facilities are considered demand-related and apportioned to the rate classes based on the production-capacity allocator; and fuel expense related to running the generation plants and net purchased power are considered energy-related and are allocated to the rate classes based on the production-energy allocator.[45] Staff's detailed BIP method calculated the capacity costs of KCP&L's base, intermediate and peak plants, determined system and class demand peaks, and analyzed each class's weather-normalized energy usage for each hour of the year.[46]

Staff developed production-capacity and production-energy allocators by matching the average capacity cost of each type of capacity cost with the BIP demands of each customer class, and by matching the average energy cost of each type of energy cost with the BIP energy requirements of each class.[47] According to Staff, KCP&L's net investment in each of the plants assigned to each of the BIP components is allocated to the classes based on each class's base, intermediate and peak demand to create its production-capacity allocator,[48] and assignments of energy characteristics of each customer class, in addition to the fuel cost for each plant, is used to create the production-energy allocator.[49]

Staff's assumptions in its development of the BIP allocators are notable. First, to allocate production costs, Staff assumes that KCP&L uses the Missouri-allocated portion of all of

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[44] See id at 13:19-22.

[45] See id at 13:1-6.

[46] See id at 13-16.

[47] See id at 17:4-7.

[48] See id at 17:12-16.

[49] See id at 17:17 -18:5.

KCP&L's generation facilities primarily to produce electricity for KCP&L's retail customers.[50] In addition, to establish class revenue responsibilities for production cost and expenses, Staff relied on assumptions about the relationship between KCP&L's generation fleet characteristics and its load characteristics.[51]

Staff's selection of a 12CP method to allocate demand-related transmission costs reflected its accounting for electricity transmitted during peak loads as well as throughout the year.[52]

Table 2 in Staff's Rate Design and Class Cost-of-Service Report indicates that under the detailed BIP CCOSS, all customer classes are currently over-contributing to the company's revenue requirement except for the LPS class which is under-contributing by 7.45% (although the Residential class's over-contribution is only 0.49%).[53] Table 3 indicates that while all other customer classes would receive a revenue requirement decrease to align rates with the cost to serve, LPS would be required to contribute close to $12 million additionally under the Company's current rates.[54]

ARGUMENTS

Of the four CCOSS submitted in this case, three of them demonstrate that the Residential class continues to be heavily subsidized by the other customer classes. Only one CCOSS, Staff's detailed BIP, shows the Residential class basically at cost under current rates, and that method

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[50] See id at 12: 9-12.

[51] See id at 13.

[52] See id at 22:7-8.

[53] See id at 5, Table 2.

[54] See id at 7, Table 3.

has been roundly criticized on the record and should be discarded on a number of grounds as discussed in this section. Cost-based rates are the best way to assure efficient electricity consumption because all classes of customers pay costs associated with serving each class. Interclass subsidies, on the other hand, produce inefficiencies. The Commission should weigh appropriately the three CCOSS that demonstrate interclass subsidies benefitting the Residential class against the one CCOSS, submitted by Staff, that demonstrates no effective subsidy to the Residential class.[55]

The 4CP and A&E cost allocation methods are superior to the A&P and BIP methods because both 4CP and A&E recognize that utilities build and acquire plant to meet their peak rather than their average demands, and that class contributions to KCP&L's summer peak demands should be the primary basis for allocating demand-related costs to the rate classes. No utility would seek to build or acquire plant only to meet its average demand because it then would not be able to reliably serve its load. No Commission with reliability responsibilities would allow a regulated utility to build or acquire sufficient capacity to meet only *average* demand. Both A&P and BIP over-allocate demand-related costs to energy-intensive customers and under-allocate those costs to customers who contribute significantly to the Company's summer peak demands and who drive the Company's need for production capacity, and neither will promote equitable and economically efficient cost-based rates.[56]

[55] DOE/FEA does not take issue with Staff's very narrow definition of the term "subsidy" in this case. ("In rare instances, a class will fail to provide revenues sufficient to match the non-capital-related expenses assigned and allocated to that class. In those instances, a class will provide a negative rate of return. If a class fails to provide revenues sufficient to meet variable expenses that is properly known as a "subsidy."") See Ex. 202 at 4: 10-14. Staff is free to define terms of art how it chooses. However, it should be understood that many industry participants, including state regulatory commissions, refer to the difference between class revenue allocations based upon a Class Cost of Service Study and existing class revenue allocations as interclass rate "subsidies." DOE/FEA uses the term "subsidy" in this manner.

[56] See DOE Ex. 501 at 4:20 – 5:4.

Furthermore, as noted by multiple witnesses in this case on the record, the BIP method is no longer reasonable in KCP&L's jurisdiction due to the Company's participation in the SPP-IM.[57] There is only one other jurisdiction identified on the record that has adopted BIP and it is an isolated municipal utility in Texas, whose operations are completely different than KCP&L's due to its participation in SPP.

Given these reasons, as discussed further below, the Commission should reject Staff's BIP method and the Company's A&P method and adopt either the 4CP or A&E cost allocation method. DOE/FEA recommends adoption of the 4CP cost allocation method along with the gradualism proposal of Dr. Schmidt.

I. THE RECORD IN THIS CASE SUPPORTS ADOPTION OF THE 4CP OR A&E COST ALLOCATION METHODOLOGY FOR KCP&L.

A. The 4CP Method produces the Most Logical Cost Allocation Results.

As noted by MIEC, the A&E and coincident peak methods of cost allocation are "the most widely used method in the industry today."[58] The advantage of the 4CP cost allocation method is its recognition that all electric utilities plan and construct generation and transmission plant, and purchase power, to meet peak demand. All customers contribute to the peak – therefore peak demand should be used to allocate demand-related (fixed) production and transmission costs.[59]

Furthermore, KCP&L is a summer-peaking utility which makes the 4CP allocation methodology the logical method to allocate fixed demand-related production and transmission

[57] See KCP&L Ex. 137, Rebuttal Testimony of Marisol E. Miller at 7:12-22; DOE Ex. 502 at 4; and Transcript, Vol. 11 at 863:3-19 (February 22, 2017).

[58] See MIEC Ex. 854, Rebuttal Testimony of Maurice Brubaker, at 18:7-9.

[59] See DOE Ex. 502 at 2:17-20.

costs to the rate classes. Demand-related production and transmission costs are fixed costs associated with the Company's production and transmission plant. KCP&L incurs these costs regardless of electricity sales to customers.[60] System peak demands drive the need for production and transmission capacity, not average demands; therefore customer contributions to system peaks should be the primary factor used to allocate fixed production and transmission costs.[61]

Application of the 4CP method achieves the most logical results. For example, application of the 4CP method to KCP&L's CCOSS results materially decreases costs to the Lighting class because it recognizes that this class of customers, on a relative basis, does not drive KCP&L's need for production and transmission capacity. In direct contrast are the detailed BIP method (combined with a 12CP method for transmission costs) and the Company's A&P method which inappropriately place significant emphasis on energy-based allocation factors that push excessive production and transmission costs onto this rate class.[62]

B. Staff Mistakes the Manner in which the 4CP Method is Applied.

As Dr. Schmidt underscores in his testimony, it is critical to note that under the 4CP method, all production and transmission plant costs are allocated during the peak period, not just the peaking plant (e.g., combustion turbine); therefore, an allocation based on 4CP picks up the costs of all of the production and transmission plant.[63] This point is crucial to understanding why the 4CP methodology is superior to the BIP method. Staff's application of the BIP method

[60] See DOE Ex. 501 at 6:11-13.

[61] See id at 8:2-4.

[62] See DOE Ex. 501 at 10-11.

[63] See DOE Ex. 502 at 7:13-16.

fails to recognize that all generation units, whether baseload, intermediate, or peaking, also serve the purpose of meeting peak demand.[64]

At hearing, a Staff witness mischaracterized the manner in which the 4CP method operates, stating:

> If true peak were the only consideration in generation and transmission system planning, no rational utility would build the interconnected generation and transmission system as it exists today. If a utility only needed to meet demands an hour or two (or hour) a year, the utility would build simple cycle combustion turbines, and perhaps rely on batteries or capacitors.[65]

The Staff witness repeated this mistake at hearing:

> You know, peak is important. But if you only cared about peak, you wouldn't build generation. You would buy capacity through the market or you would install a capacitor.
>
> You know, to have nuclear plants and coal plants as KCP&L does is a recognition that they have some load in every hour. And, hopefully, they're serving it as efficiently as possible.[66]

As clearly noted in Dr. Schmidt's Rebuttal Testimony, the 4CP cost allocation methodology allocates *all* production and transmission plant costs during the peak period, not just the peaking plant. As such, an allocation based on 4CP picks up the cost of all of the production and transmission plant.[67] Staff further stated at hearing:

> So they account for the peak by saying that it is the same cost of capacity to install a combustion turbine – turbine or buy a capacitor that only has to discharge for one second as what it is to build a coal

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[64] See id at 2:10-12. Regardless of load factor or customer class, all customers that use electric power during the peak period are responsible for the peak. Any of these types of customer could reduce their demand during the peak, and thus reduce the peak. Id.

[65] See Staff Ex. 213, Surrebuttal Testimony of Sarah L. Kliethermes, at 4:8 – 5:3. It should be noted that capacitors do not produce energy. Rather, their purpose is to improve the power factor on a current. See, for example, *Few Things That Capacitors Do Perfectly,* Electrical Engineering Portal, March 15, 2017.

[66] See Transcript, Vol. 11 at 1008:2-9 (February 22, 2017).

[67] See DOE Ex. 502 at 7:13-16.

> plant that has environmental treatment associated with it or a nuclear plant that has a lot of cost associated with that capacity initial installation.
>
> Q: And you disagree that those should be valued the same?
>
> A I disagree that those should be valued the same if you are looking – well, if the reality is that the fleet is not made up of one type of capacity, then the allocator shouldn't reflect one capacity cost.
>
> If all of KCP&L's fleet were made up of combustion turbines or all of KCP&L's flees were made up of nuclear facilities, then there's some reasonableness to that.[68]

But this reasoning misses the crucial fact that the 4CP cost allocation methodology does not seek separate allocators for each type of plant at all. Rather, it creates one allocator to allocate the total cost of Company-owned generation. The use of a single allocator more accurately reflects cost causation as compared with Staff's method because it allocates production costs to customers irrespective of SPP dispatch instructions or ever-changing class energy usage.

Notwithstanding these misunderstandings, the record is clear that the 4CP cost allocation methodology is the most logical method to allocate demand-related production costs to the customer classes and the Commission should reject arguments to the contrary.

II. THE A&P COST ALLOCATION METHOD PROPOSED BY THE COMPANY VIOLATES COST CAUSATION PRINCIPLES AND SHOULD BE REJECTED.

The A&P method does not follow cost causation principles, and should be rejected by the Commission, because if production and transmission plant costs are allocated on the basis of average energy use, then low load factor customers receive the benefits of cheaper baseload (and

[68] See Transcript, Vol. 11 at 978:16 – 979:9 (February 22, 2017).

intermediate) energy without paying a fair share of the capital costs for these plants.[69] KCP&L proposes to allocate over 56% of its demand-related production and transmission costs to the rate classes on the basis of energy usage and only 44% based on peak demands.[70] As MIEC argues, since generation facilities must be designed to carry the peak loads imposed on them, the heavy weighting given to energy consumption (56%) in the allocation factor is not related to cost of service at all.[71]

The A&P method also fails to properly allocate fuel costs. KCP&L allocated average monthly fuel costs on the basis of class energy use and ignored any matching of fuel costs and customer energy use by capacity type. The effect of this misallocation is two-fold: first, higher load factor classes will pay a disproportionately large share of expensive baseload plant costs without receiving the corresponding benefit of lower baseload fuel costs; and second, low load factor classes with predominantly peak usage will receive the benefit of lower baseload fuel costs without being allocated a corresponding share of baseload plant costs.[72] As MIEC states, the A&P method is highly non-symmetrical in that it burdens high load factor classes with above-average capacity costs but does not allow those classes to benefit from the lower cost of energy that goes with the higher capacity costs.[73]

The A&P method double counts average demand. This shown in Figure 1 of MIEC witness Mr. Brubaker's Rebuttal Testimony. As shown, when roughly equal weighting is given to the average demand and the contribution to system peak demand, as the Company proposes in

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[69] See id at 8:1-7.

[70] See DOE Ex. 501 at 7:11-14. See also Ex. 854, Rebuttal testimony of Maurice Brubaker at 3:20-22.

[71] See MIEC Ex. 854 at 7:14-16.

[72] See DOE Ex. 501 at 8:12-23. See also MIEC Ex. 854 at 8.

[73] See MIEC Ex. 854 at 11:2-6.

its application of the A&P method, the average demand is double-counted[74] as the Commission found in its Report and Order in Docket ER-2014-0258 (*Ameren Missouri*) stating:

> The weakness with the P&A methodology is that after dividing the average and excess components, instead of allocating just the excess average demand to the cost-causing classes, it allocates the entire peak demand to the various classes. That has the effect of double counting the average demand and allocates more costs to the large industrials that have a steady but high average demand that does not contribute as much to the system peaks. That method works to the benefit of the residential class whose usage varies more by time of day and time of year.[75]

The Company's proposed revenue spread is also faulty. KCP&L has proposed an across-the-board revenue spread equal to the proposed system average increase of 10.77%. However, such a proposal does nothing to reduce the subsidy identified by the Company and substantiated by the 4CP allocation methodology. In fact, adopting the Company's across-the-board spread would only exacerbate the existing subsidy.[76]

III. THE COMMISSION SHOULD REJECT STAFF'S BIP COST ALLOCATION METHOD BECAUSE ITS APPLICATION WOULD RESULT IN RATES THAT ARE UNJUST AND UNREASONABLE IN VIOLATION OF MISSOURI STATUTE.

Missouri law requires:

> At any hearing involving a rate sought to be increased, the burden of proof to show that the increased rate or proposed increased rate is just and reasonable shall be upon the gas corporation, electrical corporation, water corporation or sewer corporation…

Mo. Ann. Stat. § 393.150.

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[74] See MIEC Ex. 854 at 6:11-18.

[75] Report and Order at 70-71, ¶6, Docket ER-2014-0258 (*Ameren Missouri*), April 29, 2015. P&A refers to "Peak and Average", which is synonymous with Average and Peak.

[76] See DOE Ex. 501 at 11:8-13.

Missouri courts have applied the Missouri Public Service Commission Law's "just and reasonable" standard to the element of rate design.[77] There are several reasons adoption of Staff's proposed BIP cost allocation method would fail §393.150's just and reasonable standard. First, the BIP method produces results that are an outlier in this case. Second, the BIP method is not relevant to KCP&L's operational practices. Third, the Commission has not previously adopted the BIP method in a precedent-setting manner.

A. The BIP Method Produces Results that Are an Outlier in this Case.

First and foremost, the results of Staff's CCOSS utilizing the BIP method are an outlier in this case. Three of the four CCOSS submitted in this case demonstrate clearly that one class is being heavily subsidized by the other rate classes. The results of the Company's A&P method requires a 20% increase to Residential class rates to align them with the cost to serve.[78] Company witness Miller indicates KCP&L's CCOSS shows that larger commercial and industrial customers, including LPS class customers, are paying above cost-based rates, and in some cases, significantly so.[79] The results of MIEC's A&E method requires a 14.8% increase to the Residential class;[80] and the results of DOE/FEA's 4CP method requires a 29.4% increase to the Residential class to align revenue allocations with the cost to serve under the Company's proposal (ignoring for the moment the gradualism adjustments proposed by DOE/FEA and

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[77] See *State ex rel. Pub. Counsel v. Missouri Pub. Serv. Comm'n,* 289 S.W.3d 240, 247 (Mo. Ct. App. 2009) ("Even if the Commission had found that Atmos was entitled to a $3.4 million revenue increase, such a finding does not serve as a substitute for a determination of the impact of the SFV rate design, which must stand on its own as a just and reasonable rate design.")

[78] See KCP&L Ex. 136 at 14:13.

[79] See id at 14. The second Table on this page demonstrates that the Residential class requires a 20% revenue allocation increase under the Company's revenue request proposal. See also, Ex. 501at 5:5-6.

[80] See MIEC Ex. 853 at 26:9-19 and Schedule MED-COS-5.

MIEC witnesses).[81] Only the BIP method places the Residential class's contribution within ½ percent of the Company's cost to serve that class. The Commission should reject this obvious outlier.

B. The BIP Methodology is No Longer Relevant to the Operational Practices of KCP&L.

The BIP methodology simply does not reflect the current reality of KCPL's operations. The power supply planning and operation of individual power supply resources within a centrally-dispatched power pool like the SPP-IM, of which KCP&L is a participant, cannot be attributed to the specific customer classes of load-serving entities ("LSE's") within that power pool.[82]

Notably, the BIP method has been rejected by utilities themselves. In this very case, KCP&L's rate design witness states that BIP is no longer suitable to allocate production costs due to the Company's transition to the SPP-IM:

> For a time, the Company believed the BIP method to be reasonable, but due to concerns with the transition of the SPP to an Integrated Marketplace (IM) with centralized dispatch, the Company decided the Average & Peak method was more appropriate. To utilize the BIP allocator one must assign the generating units into base, intermediate, and peak groups based on their use. Prior to the IM market, the Company provided its own generation to meets its load requirements. With the introduction of the IM market, we no longer use our generation to meet the Company's load requirements, but instead sell generation into the SPP market and buy our load requirements for [sic] the SPP market. It is the Company's belief that the IM market change impacts the suitability of the BIP method as the production allocation.[83]

[81] See MIEC Ex. 501 at 12, Table 2.

[82] See id at 2:5-9.

[83] See KCP&L Ex. 137 at 7:12-22.

Other utilities subject to the jurisdiction of the Missouri PSC have similarly criticized and rejected the BIP method. As noted during the hearing by Mr. Woodsmall:

> In the Ameren case, this happened as well. And what did Ameren say? Ameren's own witness said, quote, [I]t is clear Staff's analysis is an outlier when compared to the other studies.
>
> So here's a utility company saying Staff's methodology is an outlier. What did Empire say when faced with the same thing? Quote, The Staff also uses a method that is arbitrary and suffers from incorrect assumptions and arbitrary weightings.[84]

Evidence of overall acceptance of the BIP method is sparse if at all existent. The entire record in this case includes mention of a single jurisdiction outside Missouri that has adopted results of the BIP method and even that sole example is completely irrelevant here, as Dr. Schmidt demonstrated at hearing:

> Q And can you tell me what your knowledge is of that Texas case?
>
> A Well, in Texas, as you probably know, it's an isolated system. They are not interconnected with the other states. They are a utility pool line of their own. So, consequently, the BIP method, to some extent, can be considered there because they are the traditional base, intermediate and peak type utility. They're not interconnected such as Kansas City Power & Light with the -- with the Southwest Power Pool.[85]

BIP is outdated in that it assumes that the utility is an isolated entity that generates and delivers its own power in response to load. In today's SPP-IM, SPP members like KCP&L do not directly generate to load. Rather, SPP determines, based upon prices, which generators are chosen in the "stack" from an extensive portfolio of resources.[86] That stack may or may not match the load characteristics of an individual utility within SPP, and thus, the manner in which

[84] See Transcript, Vol. 11 at 862:15-24 (February 22, 2017).

[85] See Transcript, Vol. 12 at 1096:7-18 (February 23, 2017).

[86] See DOE Ex. 502 at 4:7-12.

KCP&L's plants run at different times of the day and during different seasons of the year actually determines its costs to deliver energy and capacity to its customers.[87] The important point here is that as an LSE, KCP&L is a buyer in the SPP-IM and takes electricity from the SPP market *without regard to its generation source.*[88]

The transition to a nodal market changed the manner by which generation planning and operation occurs – in the nodal market, SPP establishes the amount of generation capacity that is required to meet estimates of peak demands. It is up to individual LSEs to determine what type of plant they are willing to build based upon a variety of factors,[89] but KCP&L no longer serves its load by matching its own resources to that load; rather, it also buys and sells power based on the ever-changing cost of that power in the SPP-IM. In other words, generation is utilized based upon power supply prices, not individual utility system load.[90] Ultimately, this separation of the identification of demand capacity needs from the selection of the type of generation plant to build renders obsolete the production allocation methodologies, such as BIP, which match loads and plant types.[91]

Staff mistakes the ability of the detailed BIP method to determine costs given KCP&L's participation in the SPP-IM. When asked why the detailed BIP method is the most appropriate CCOSS method to adopt in this case, Staff witness Kliethermes responds:

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[87] See id at 4:12-17.

[88] See id at 4:17-18.

[89] Factors could include load levels including reserves, hours of use, estimated future fuel costs, environmental factors, water availability, capital costs, construction cost estimates, and other such information. See DOE Ex. 502 at 5:17-19.

[90] See DOE Ex. 502 at 5:15-22.

[91] See id at 6:2-5.

> So if you're going to recognize those variable costs of energy over the course of the year, it's important to also recognize the varying cost of the capacity that were used to produce that energy.[92]

Here, Staff erroneously implies that it is accounting for the cost of capacity that produced some specific energy. But KCP&L's cost of energy from the SPP-IM results from competitive bidding by generation owners into the SPP-IM and economic dispatch by SPP of the region's generation fleet. The cost of capacity to produce that energy is not something that is, or can be, known by Staff, or any other party to this case because it is the region's generation fleet that is dispatched by SPP, not KCP&L's generation fleet in isolation. Staff's application of its detailed BIP method to KCP&L's demand-related production costs does not, contrary to Staff's representation, recognize the varying cost of capacity used to produce the energy that KCP&L's customers required.

C. Staff Mistakes the Commission's Adoption of the BIP Method in the Empire District Case for a Commission Endorsement of the Method.

Staff inappropriately attempts to equate the Commission's use of the results of a Staff cost allocation methodology with Commission support for Staff' methodology in a prior case, when the relative merits of the cost allocation methods proposed were clearly not at issue in that case. Staff witness Kliethermes states that the Commission "explicitly relied on Staff's detailed BIP allocation study in the Empire District Electric Company's 2014 rate case" ("Empire District Case") when it stated:

> [o]f the four CCOS studies submitted by the parties, Staff's most reasonably recognizes the relationship between the cost of the plant required to serve various levels of demand and energy requirements and the cost of producing energy.[93]

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[92] See Transcript, Volume 11, at 977:13-17 (February 22, 2017).

[93] See Staff Ex. 212 at 2:20-3:2 (citing Report and Order in Case No. ER-2014-0351 at 15 and Order Clarifying Report and Order at 2).

In the Empire District Case, the Commission properly recognized that more movement toward cost-based residential rates was appropriate than the stipulation that the settling parties had agreed to. Having rejected the settling parties' proposal to increase residential rates by less than 1 percent more than the system average percentage increase, the Commission selected a CCOSS that would (1) justify a more meaningful move toward cost-based residential rates; and (2) serve as a basis for reallocating revenues among the other rate classes. Of the various CCOSS submitted in that case, all of which indicated that the residential rates were well below cost-based levels, the Commission selected Staff's CCOSS to serve as an illustrative reference point for cost-based residential revenues.[94] The Commission determined to move one-quarter of the way toward Staff's reference point (8.06%) resulting in a 2% revenue increase for the Residential class above the system average increase.[95]

The Commission's action in this case should not be confused with adoption of the BIP method of cost allocation. The Commission made this point abundantly clear, indicating:

> The Commission's June 24, 2015, Report and Order does not establish a general preference by the Commission for a specific methodology to calculate the cost of service for various rate classes.[96]

The Empire District Order did not address the incompatibility of the BIP method with generation scheduled by SPP. In fact, the Commission's Order in the Empire District Case supports Dr. Schmidt's position in this case. Dr. Schmidt's recommendation recognizes the need to move

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[94] See DOE Ex. 503, Surrebuttal Testimony of Michael R. Schmidt, at 1-2.

[95] Id. See also, Order Clarifying Report and Order, Docket No. ER-2014-0351 at 1, July 1, 2015.

[96] See Order Denying Motion for Clarification/Reconsideration, Docket No. ER-2014-0351 at 2, July 22, 2015.

further towards cost of service and the use of gradualism to avoid rate shock – precisely the Commission's action in the Empire District Case.[97]

DOE/FEA urges the Commission to reject Staff's detailed BIP method outright and instead, adopt the 4CP method to best align rates with the cost to serve the customer classes.

IV. THE COMMISSION SHOULD REFRAIN FROM ADOPTING INTRA-CLASS ADJUSTMENTS TO THE LPS OR LGS RATE CLASS UNTIL THE COMPANY STUDIES INTRA-CLASS COST OF SERVICE.

MIEC witness Mr. Brubaker proposed a change to the LGS and LPS rates in this case. His proposal seeks to freeze the tail block energy rate by keeping its revenue allocation at current levels, increase the middle block energy rate by 75% of the average percentage increase, and collect the balance of the revenue requirement by applying a uniform percentage increase to the remaining charges in the tariff.[98] The other charges in the LPS class include the customer charge, the reactive demand charge, the facilities charge, and demand charges and the initial block energy charges.[99]

But as Mr. Brubaker himself states, the Company should examine the tariff schedules and attempt to move the rate elements closer to cost of service.[100] DOE/FEA recommends that the Commission reject Mr. Brubaker's proposed changes to the LGS and LPS rate classes until some evidence is submitted to the Commission that provides a basis upon which to authorize an intra-class cost shift.

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[97] See DOE Ex. 503 at 4:8-15.

[98] See MIEC Ex. 853 at 32:3-10 and Schedules MEB-COS-7 and MEB-COS-8.

[99] See id.

[100] See id at 33:12-14.

Adoption of Mr. Brubaker's proposal at this time would burden the initial LGS and LPS blocks with additional costs that may be unwarranted, as it is as yet unknown what the relative responsibilities of each block should be regarding fixed costs. Compounding this burden is the fact that the middle and tail blocks benefitted from the adoption of an identical proposal in KCPL's last rate case before the Commission as a stipulated agreement – again, without the benefit of record evidence.[101] Rather than further pushing additional class costs onto initial block customers, DOE/FEA recommends adopting an equal percentage increase to the LGS and LPS classes, as recommended by Staff and the Company, and revisiting the matter once the Company has examined the intra-class customer blocks.

V. CONCLUSION

The Commission has a unique opportunity in this case to correct existing interclass subsidies and to begin to align rates with the cost of service, while avoiding rate shock to any customer class. To do this, the Commission should adopt a cost allocation methodology that is well-regarded in the industry, supported by the record evidence, and reflective of KCP&L's actual operations. DOE/FEA recommends the Commission adopt the 4CP cost allocation methodology because it allocates costs independent of energy sales to customers, recognizing that utilities build and acquire plant to meet their peak - not average - demands. The Commission should also adopt Dr. Schmidt's gradualism proposal to ensure that no customer class experiences rate shock. DOE/FEA recommends the Commission reject the A&P and BIP cost allocation methodologies because they violate cost causation principles and result in rates

[101] See Non-Unanimous Stipulation and Agreement on Certain Issues, Docket No. ER-2014-0370 at 3, June 16, 2015.

that are unjust and unreasonable. Finally, DOE/FEA recommends the Commission adopt an equal percentage increase to all blocks in the LGS and LPS customer classes.

WHEREFORE, based upon the testimony of Dr. Schmidt and the arguments contained herein, DOE/FEA respectfully requests that the Commission adopt the 4CP cost allocation methodology and gradualism proposal, and adopt an equal percentage increase to all blocks in the LGS and LPS customer classes.

Respectfully Submitted,

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Date: March 22, 2017

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that, on this 22nd day of March 2017, the foregoing Initial Brief was:

(1) formally placed on the Commission's website via the Commission's Electronic Filing and Information System ("EFIS") in accordance with applicable procedure; and

(2) served via electronic mail on all of the entities and individuals, and all of the legal representatives of all of the entities and individuals, including Commission Staff, whom the EFIS at this date identifies as parties or petitioners for intervention herein.

Rishi Garg

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United States Department of Energy