BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Annual Revenues for Electric Service	))))	Case No. ER-2021-0337

POST-HEARING BRIEF OF
THE MISSOURI INDUSTRIAL ENERGY CONSUMERS

COMES NOW the Missouri Industrial Energy Consumers ("MIEC") and for its Post-Hearing Brief states as follows:

Introduction

The issues remaining for decision in this case are (1) which class cost of service study "CCOSS" should be adopted; (2) how should the rate increase among the customer classes (3) whether to approve the non-residential rate design changes proposed by the Commission Staff. The outcome of these issues depends on whether the Commission finds that class cost of service should be considered in setting Ameren's electric rates in this case.

Historically, the Commission's starting point for deciding the allocation of a rate increase is the principle that the customer class that causes a direct cost should pay that cost. Class cost of service is the foundation of just and reasonable rates for the following reasons:

1. **Equity.** Cost-based rates ensure that each customer pays what it costs for the utility to provide service to that customer. If rates are not based on cost of service, some customers will unfairly pay costs attributable to providing service to other customers.
2. **Conservation.** Cost-based rates incentivize the efficient use of energy and provide customers with a balanced price signal for making decisions on electric consumption and demand-side management investments.

3. **Engineering Efficiency.** Cost-based rates prevent the utility from extracting a disproportionate share of revenues from customer classes that have alternatives (such as producing products at other locations where costs are lower). If rates are not based on cost of service, the utility may need to either discount rates to those customers or lose load. Cost-based rates prevent both uneconomic rate increases and discounts so that the utility, stockholders and customers (or some combination of all three) are economically aligned.

Although cost of service is the starting point for setting just and reasonable rates, the Commission has broad discretion to consider other factors such as gradualism, economic growth, job retention, rate stability, revenue stability, public acceptance, simplicity and ease of administration. Additionally, cost-based rates benefit Missouri's economy by enabling customers to predict and manage electricity costs. This makes Missouri more attractive to employers and helps Missouri to retain and attract production.

Based on the weight of the evidence, the MIEC urges the Commission to provide movement to cost-of-service in this case. Ameren is increasing and accelerating capital spending, spurred by major changes to Missouri law enacted by SB 564 (passed in 2018) and SB 745 (passed in 2022). These statutes limit the Commission's rate setting authority (authorizing several rate setting methods previously rejected by the Commission) and provide Ameren with additional financial incentives for large capital spending above and beyond the compelling incentives for capital spending inherent in Missouri's traditional regulation of electric utilities. For these reasons, Ameren will continue to pursue major rate increases in the foreseeable future. This makes it is especially important to reduce interclass rate subsidies gradually before those subsidies become so large that the Commission will have great difficulty addressing them.

Summary of MIEC Evidence and Recommendation

1. The Commission should determine class cost of service in this case based on the studies submitted by MIEC and Ameren. These studies use the Average and Excess 4 Non-Coincident Peak allocation (A&E 4NCP) method and are reasonable.

2. The Commission should allocate the rate increase to the customer classes to move rates toward the class cost of service shown in the MIEC and Ameren studies. The MIEC believes that the rate increases in this case be allocated to customer class primarily based on cost-of-service principles. The MIEC therefore recommends movement to cost of service at present rates, followed by an equal percentage increase.[1] In the alternative, if the Commission decides not to move to cost of service, the MIEC recommends that the Commission allocate the rate increase to the customer classes to move rates 50 percent toward the class cost of service shown by the MIEC and Ameren cost of service studies.[2] Finally, the MIEC notes that it has provided MIEC Witness Brubaker's Hearing Exhibit 533, which illustrates a modest 50 percent movement toward cost of service pursuant to the parties' stipulation for a revenue requirement settlement in this case.[3]

3. The Commission should reject the Staff's class cost of service study. The Staff's study contains serious errors, is based on severely flawed analysis and is completely out of the realm of any accepted cost of service methods.

[1] Exhibit 350, Direct Testimony of Maurice Brubaker Schedule MEB-COS-5

[2] Id., Schedule MEB-COS-6

4. The Commission should reject the Staff's proposals for various non-residential rate design changes. Staff's rate design proposals are unsupported by the record in this case. These proposals should only be considered in a future Commission case after sufficient data is provided by Ameren for evaluation and discussion by all interested parties so that the parties can provide data-based rate design recommendations to the Commission.

Class cost of service studies are performed to allocate costs to customer rate classes based on which customer class is causing those costs and are a tool for designing rates that fairly assign cost responsibility to each customer class.[4] Class cost of service studies identify the cost responsibility of the customer class and provide the foundation for revenue allocation and rate design. This is accomplished by first identifying the types of utility costs (functionalization), determining their primary causative factors (classification), and apportioning each cost among the rate classes (allocation). Adding up the individual pieces determines the total costs of each customer class.[5]

Ameren's load pattern has predominant summer peaks, and these demands should be the primary ones used in the allocation of generation and transmission costs. Demands in other months do not require the addition of generation capacity and therefore should not be used in determining the allocation of costs. [6] The utility's annual load pattern is the central factor in determining the appropriate method for allocating fixed, or demand-related, costs on a utility system. To be consistent with cost-causation, the method chosen for allocating these

[4] Exhibit 350, Brubaker Direct p. 4, ll. 14-20

[5] Id. at p. 9, ll. 5-10

[6] Id. at p. 25, ll. 4-10

costs among the various customer classes should reflect the contribution of each customer class to the peak demands that cause the utility to incur capacity costs.[7]

A. The Commission should determine class cost of service in this case based on studies submitted by MIEC and Ameren, which are reasonable and yield similar results through their use of the Average and Excess 4 Non-Coincident Peak allocation method.

The MIEC and Ameren filed similar class cost of service studies ("CCOSS) in this case using the Average and Excess ("A&E") 4 Non-Coincident Peak (4 NCP) allocation method.[8] The A&E method is a family of CCOSS methods which consider both the maximum rate of use (demand) and the duration of use (energy). The A&E method makes a conceptual split of the system into an "average" component and an "excess" component. The "average" demand is the total kWh demand divided by the total number of hours in the year (the amount of capacity required to produce the energy if taken at the same demand rate each hour). The system "excess" demand is the difference between the system peak demand and the system average demand.[9]

Under the A&E 4 NCP method, the average demand is allocated to classes in proportion to their energy usage. The difference between the system average demand and the system peak(s) is then allocated to customer classes based on a measure representing their "peaking" or variability in usage. Thus, A&E methodology properly considers class maximum demands and energy usage, as well as diversity between class peaks and the system peak.[10]

[7] Exhibit 350, Brubaker Direct at p. 24, l. 17 to p. 25, l. 3.

[8] As discussed further below, the MIEC's CCOSS differs from Ameren's CCOSS regarding the classification of certain non-fuel O&M expenses.

[9] Exhibit 350, Brubaker Direct at p. 25, l. 17 – p. 26, l. 8 *citing* NARUC Electric Cost Allocation Manual (1992) at p. 81.

[10] Id. at Brubaker Direct at p. 27, ll. 8 - 11

The A&E 4 NCP methodology is reasonable and appropriate in this case for several reasons. First, this method accounts for both class demands and class energy consumption, which are the two major factors that drive the utility's capacity needs. Second, this method comports Section 393.1620.1(1) RSMo., because it is an identified method for nuclear and fossil production plant cost allocation under the National Association of Regulatory Commissioners (NARUC) 1992 manual.[11] Third, this method takes into account that almost all of the 4 NCP monthly demands occur during the summer months.[12] Fourth, the use of the 4 NCP demand option (rather an option with fewer monthly NCP demands) stabilizes the impact of extreme demand in a given month.

For the most part, the actual revenue adjustment recommended by both MIEC and MECG align with the results of Ameren Missouri's study. The MECG's position is aligned with Ameren Missouri's with one exception related to production allocations.[13] As explained below, the MIEC's study uses Ameren Missouri's study as a starting point and modifies several allocations.[14]

The MIEC's study differs from Ameren's study because it more closely reflects cost of service in several key respects, and although Ameren's study is reasonable, the MIEC's is the most reasonable study in evidence and should therefore serve as the basis for the Commission's decision in case.[15]

First, the MIEC's study differs from Ameren Missouri's study regarding the treatment of income taxes. The MIEC calculates income taxes based on present rates based on the

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[11] Exhibit 350, Brubaker Direct at p. 30, ll. 1 – 6.

[12] Id. at p. 27, l. 23, through p. 28, l. 2.

[13] Id. at p. 27, l. 24 through p. 28, l. 2

[14] Id. at p. 35, ll. 9 – 15.

[15] Id. at p. 31, ll. 12 – 20.

taxable income of each class, instead of allocating income taxes on rate base as done by Ameren Missouri in its CCOSS. The MIEC's approach changes the rate of return at present rates, but (when applied consistently) does not change the amount of the increase or decrease required to move to cost of service.[16]

Second, the MIEC witness Brubaker disagrees with Ameren Missouri's CCOSS in its allocation of transmission costs. Ameren Missouri has allocated transmission costs using 12 monthly coincident peaks. However, the transmission system must be built to meet system peak demand, which occurs in the summer; it was not built to meet the average of the 12 monthly peak demands, some of which as significantly lower (as much as 43% lower) than in the summer peak demand. In this respect, the transmission system is similar to the generation system. Although Mr. Brubaker disagrees with Ameren Missouri's allocation in this regard, he did not find the dollar amounts to be material and therefore simply used Ameren Missouri's allocation of transmission system costs.[17]

Third, the MIEC's CCOSS differs from Ameren Missouri's study regarding classification of generation O&M expense.[18] The MIEC's CCOSS shows that most appropriate approach is to classify all of the generation O&M expense other than fuel and purchased power as a fixed cost. This is sometimes referred to as the "expenses follow plant" basis.[19] In contrast, Ameren Missouri's CCOSS recommends that non-fuel, non-labor costs of production and O&M expense be treated as a variable cost and allocated on the basis of class energy usage. Ameren's approach to allocation of these costs is inappropriate because these costs are fixed and are incurred regardless of the amount of electricity generated at the

[16] Id. at p. 31, ll. 1-18

[17] Id. at p. 33, ll. 1-14

[18] Id. at p. 33 l. 15 to p. 35, l. 2

generating units. These costs do not vary in any material respect with the number of kWh generation. Rather, the vast majority of these costs occur primarily as a function of the existence of plants, the hours of operation and the passage of time. In fact, Ameren Missouri scheduled the maintenance on its coal and nuclear generation units on a "passage of time" basis, not on a "kWh generated" basis. Accordingly, MIEC's CCOSS provides a more appropriate treatment of income taxes and a more appropriate treatment of O&M expense than Ameren Missouri's CCOSS.[20]

Because the MIEC's COSSS allocates income taxes and O&M expenses in a manner best reflects cost causation, the MIEC study performed by MIEC witness Brubaker is the "most reasonable" of the class cost of service studies in this case and should be adopted by the Commission as the basis for decision.

[20] Brubaker Direct at p. 33, l. 15 to page 35, l. 2

Based on the considerations explained above, Schedule MEB-COS-5 of MIEC witness Brubaker's Direct Testimony shows the adjustments that would be needed prior to any overall rate change in order to fully move to cost-of-service based rates:[21]

AMEREN MISSOURI
Case No. ER-2022-0337

Class Cost of Service Study Results
and Revenue Adjustments to Move Each Class to Cost of Service
Using MIEC's Modified ECOS at Present Rates
(Dollars in Thousands)

Line	Rate Class	Base Revenues (1)	Current Rate Base (2)	Adjusted Operating Income (3)	Earned ROR (4)	Indexed ROR (5)	Income @ Equal ROR (6)	Difference in Income (7)	Revenue Change (8)	Percent Change (9)
1	Residential	$ 1,373,010	$ 6,347,277	$ 259,899	4.095%	80	$ 326,853	$ 66,954	$ 89,272	6.5%
2	Small GS	305,323	1,364,967	66,679	4.885%	95	70,289	3,610	4,814	1.6%
3	Large GS/Primary	791,487	3,022,209	203,091	6.720%	130	155,629	(47,462)	(63,283)	-8.0%
4	Large Primary	205,821	668,517	56,276	8.418%	163	34,425	(21,851)	(29,134)	-14.2%
5	Company Owned Lighting	39,011	185,999	11,631	6.253%	121	9,578	(2,053)	(2,737)	-7.0%
6	Customer Owned Lighting	2,933	16,810	65	0.385%	7	866	801	1,068	36.4%
7	Total	$ 2,717,585	$ 11,605,779	$ 597,640	5.150%	100	$ 597,640	$ -	$ -	0.0%

Schedule MEB-COS-5

[21] Brubaker Direct, Schedule MEB-COS-5.

Should the Commission decide not to make full movement to cost of service in this case, MIEC provides the alternative proposal shown Schedule MEB-COS-6 to the Mr. Brubaker's Direct testimony, showing the adjustments that would be needed prior to any overall rate change in order to move 50 percent toward cost-of-service based rates:[22]

AMEREN MISSOURI
Case No. ER-2022-0337

Cost of Service Adjustments for
50% Movement Toward Cost of Service
Using Modified ECOS at Present Rates
($ in Millions)

Line	Rate Class	Current Revenues (1)	Move 50% Toward Cost Of Service[(1)] (2)	Adjusted Current Revenue (3)	Revenue-neutral Percent Change in Current Revenue (4)
1	Residential	$ 1,373.0	$ 44.6	$ 1,417.6	3.3 %
2	Small GS	305.3	2.4	307.7	0.8 %
3	Large GS/Primary	791.5	(31.6)	759.8	(4.0)%
4	Large Primary	205.8	(14.6)	191.3	(7.1)%
5	Company Owned Lighting	39.0	(1.4)	37.6	(3.5)%
6	Customer Owned Lighting	2.9	0.5	3.5	18.2 %
7	Total	$ 2,717.6	$ -	$ 2,717.6	0.0 %

(1) Increase to equal cost of service from column 8 of Schedule MEB-COS-5, times 50%.

Schedule MEB-COS-6

[22] Exhibit 350, Brubaker Direct, Schedule MEB-COS-6.

Additionally or the Commission's consideration, Mr. Brubaker's analysis presented in MIEC Hearing Exhibit 353 illustrates a 50 percent movement toward cost of service under the revenue settlement stipulation proposed in this case:

AMEREN MISSOURI
CASE ER-2022-0337

Customer Class Increases

Rate Class	Percentage Increase to Achieve Cost of Service at Ameren's Proposed Rate Increase [1]	Relative Percent Increase	Percent Increase at Settlement Increase of 5.14%	Approximate Increase for 50% Movement [2]
	(1)	(2)	(3) = (2) x 5.14%	(4)
Residential Service	18.6%	1.60 times average	8.22%	6.7%
SGS	13.4%	1.16 times average	5.96%	5.6%
LGS/SPS	3.0%	0.26 times average	1.34%	3.2%
LPS	-3.8%	-0.33 times average	-1.70%	1.7%
Ameren Lighting	6.0%	0.52 times average	2.67%	3.9%
Customer Lighting	52.4%	4.52 times average	23.23%	14.2%
Total	**11.6%**	**Average**	**5.14%**	**5.14%**

Note:
[1] Michael W. Harding Direct Testimony, page 5
[2] Calculation for (4) = 5.14% + [(3) - 5.14%] x 50%

B. <u>The Commission should reject the class cost of service study submitted by the Commission Staff, which is unreasonable because it fails to reflect cost-causation, contains serious errors, and is far outside the realm of any accepted cost of service methodology used in the electric utility industry.</u>

1. Staff's CCOSS Method

Staff allocates functionalizes and allocates production costs by designating generation resources as either Type 1 or Type 2. Type 1 resources are defined as those for which there are little or no variable costs incurred when the unit is offline and generally fully dispatchable. Type 2 resources are defined as having little or no variable costs with the dispatch often limited by weather conditions or other factors beyond the control of the utility.

For Type 1 resources, variable revenue requirement components and stable revenue requirement components were designated.[23]

Staff allocates Type 1 resources based on customer class loads during certain identified hours. Staff refers to the "All Peak Hours Approach" described in the 1992 NARUC Electric Utility Allocation Manual ("Manual") and uses class loads during what the Midcontinent Independent System Operator ("MISO") calls "Resource Adequacy hours, offset by the class allocation of hourly generation of production Type 2 resources."[24]

Resource Adequacy Hours are those that MISO reviews to determine the likely availability of generation resources. Schedule III of Schedule 53 of the MISO tariff defines RA hours as ". . . the periods of highest risk and greatest need during a Season and throughout the year. They include hours during Maximum Generation Emergency declarations and the hours when the operating margin, a measure of available supply capacity above demand and reserve requirements, is at its lowest." Generation resource performance during those hours is evaluated to determine the capability rating of a generation resource.[25]

Loads used during RA hours are used solely to define the availability of generation resources owned by or available to MISO members. The capacity responsibility is each load serving entity ("LSE") equals its expected load at the time of MISO peak demand plus a reserve margin percentage which established by MISO based on reliability considerations.[26]

Contrary to Staff's CCOSS, the fact that MISO considers loads and resources during all four seasons periods does not change how costs should be allocated among retail customers. Ameren Missouri's summer season demands are substantially higher than

[23] Exhibit 351, Rebuttal Testimony of Maurice Brubaker, p. 3, ll. 9 – 16.

[24] Id. at p. 3, ll. 17 – 23.

[25] Exhibit 351, Rebuttal Testimony of Maurice Brubaker at p. 4, ll. 1 – 9.

[26] Id. at ll. 1 – 13.

demands in other seasons, and generally speaking, having sufficient capacity to meet the summer loads has been sufficient to meet loads in the other seasons.[27] Accordingly, the A&E-4NCP method remains a reasonable allocation to use for Ameren Missouri. MISO's evaluation of conditions in four seasons provides no basis for allocating any costs classes based on hourly loads in those seasons.[28]

Staff baselessly allocates the revenue requirement associated with Type 2 facilities based on a "Partial Energy Weighting" method. The details are not further explained, but the allocation is more heavily weighted than the allocation used for Type 1 resources. The is no justification for this allocation.[29]

Staff applies different allocations to its three categories of Type 1 Resources, Type 2 Resources, and Purchases and Sales. The Staff uses different methods and assumptions for each of these production resources.[30] Staff's approach of trying to allocate different resources using different allocation approaches is inappropriate, unnecessary, and inconsistent with generally accepted electric utility cost allocation practices. Generation and purchase power resources are categorized into fixed and variable costs. The variable costs are allocated based on class energy consumption, and the fixed costs are allocated based on some measure of demand responsibility, such as A&E 4NCP. By trying to allocate different resources in different ways, Staff ignores the fact that particular resources are not built for particular customer classes or segments of load. Rather, electric utilities construct a portfolio consisting of various kinds of resources in a manner designed to reliability meet customer

[27] Id. at p. 4, l. 18 – p. 5, l. 7

[28] Id. at p. 5, ll. 8 – 12.

[29] Id. at p, 5, ll. 13 – 19.

[30] Exhibit 351, Brubaker Rebuttal, p. 6, ll. 1 – 5.

requirements at least cost. For these reasons, the Staff's approach does not follow cost causation, is highly unusual and should be rejected.[31]

Nonsensically, Staff allocates production sales and purchases on an hourly analysis by which Staff attempts to define the value of energy generated by the assets allocated to each class in each hour of the year, the result is that while most classes are allocated a cost associated with revenues and purchases, some classes get a credit. Bizarrely, Staff's allocation shows the Residential class receives a credit of $200 million, out of a total credit of $55 million. This must be ferreted out, as it is buried along with other allocations. An unlabeled table in Staff witness Sarah Lange's Direct Testimony contains a line titled "Functionalized Net Revenue Requirement" for the production function. This line consists of three components: (1) the revenue requirement for Type 1 generation facilities; (2) the revenue requirement for Type 2 generation facilities; and (3) the revenue requirement for "Production Revenues and Purchases". Numbers are shown for each class, but unfortunately not for the total. By extracting the information for Production Revenue & Purchases, MIEC witness Brubaker was able to determine that Staff's analysis shows system total revenues of about $55 million, but as indicated above, the Residential class receives about $194 million of credit. Staff's approach effectively treats some classes as "sales for resale" entities because Staff effectively creates sales from some customers to others. This phenomenon is unprecedented and illogical and demonstrates that Staff's CCOSS should be rejected.[32]

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[31] Id. at ll. 1 – 18.

[32] Exhibit 351, Brubaker Rebuttal, p. 6, l. 19 – p. 9, l. 17.

Staff CCOS study tells a completely different story the studies presented by Ameren Missouri, the MIEC and the MECG.[33] Ameren Missouri, MIEC and MECG show that the Residential and Small General Service (SGS) customers are providing well below target returns, while the Large General Service (LGS), Small Primary Service (SPS) and Large Primary Service (LPS) customers are providing well above target returns. Staff's results indicate almost the opposite, showing Residential and SGS customers close to target and Large General Service, Small Primary Service and LPS customers are paying below target.[34] These directional differences and the magnitude of difference expressed cannot lead to the conclusion that both studies are reasonable.[35]

The Staff's Class Cost of Service Report fixates on Ameren's record keeping and assignments within the distribution function. Staff criticizes Ameren heavily regarding Ameren's determination and allocation of customer costs and distribution system demand costs. It also criticizes Ameren for its inability to specifically identify costs associated with specific facilities.

At the outset, the MIEC notes that it disagrees with Staff's criticisms of Ameren's recordkeeping, assignments and allocations of distribution costs. But regardless of how Staff's distribution cost concerns may be resolved, these concerns have no material on the Large Primary Service (LPS) class.[36] The LPS class is much less sensitive to the determination and allocation of distribution cost than other classes, because the LPS class takes all of its service at primary or higher voltages. This contrasts with the residential class and other classes that take service exclusively at the secondary distribution voltage level.

[33] Exhibit 34, Direct Testimony of Thomas Hickman, p. 2, ll. 12-14.

[34] Id. at

[35] Id. at

Accordingly, Staff's arguments about the distribution system allocations, even if accepted, would have no meaningful impact on the determination of the cost to serve LPS customers. All power delivered to the LPS class is at primary voltages or higher, with no part of the service being delivered at the secondary level. In contrast, all the power delivered to the Residential class, the Small General Service class, and the Lighting Class is delivered at the secondary voltage level. Changes in the allocation of distribution-related costs would therefore have little LPS class than to others. This analysis shows that disagreements about secondary distribution level costs have no impact whatsoever on cost of service for the LPS class, and that the LPS class is much less sensitive to changes in distribution system cost determination and allocation than are other classes.

Staff indicates that changes such as how the distribution system is networked and how many smart meters can communicate with switches to reduce the duration of an outage in some cases justifies this "incredibly dramatic" shift in proposed cost responsibility that Mr. Hickman concludes "simply does not make sense".[37]

Based on the data set forth in Mr. Hickman's testimony, Ameren Missouri witness Brown concludes that Staff's allocation method is "borderline absurd". Mr. Hickman notes that any cost analyst that would "invent" a new allocation method would realize that once the study was compiled that the new allocation mimics the energy allocator and realize that is a "huge red flag and most likely a flawed methodology". Staff shows a pattern of arbitrary energy allocation with the apparent intention of shifting costs away from the Residential class to large customers without supporting cost causation.[38]

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[37] Id. at p. 6, ll. 2 – 8.

[38] Exhibit 38, Brown Surrebuttal at p. 15, ll. 16 – 23.

As observed by Ameren witness Hickman, there has been no fundamental change in how the most core and substantial components of distribution cost are used on the Ameren Missouri's distribution system to serve customers – nor the long-accepted economic rationale underlying the determination of cost causation of those components, nor the cost allocation methodologies that reflect cost causation.[39] In no way would those small incremental changes support a drastic shift of distribution related cost responsibility from 70% for the residential class down to 40%, as Staff's analysis of the residential class has done in the last few years. In no way would those small incremental changes support a shift of those same costs to indicate the Large Primary Service class should be responsible for more than five times as much the cost associated with that underlying investment, as Staff's analysis also suggests.

Similarly, Ameren Missouri witness Brown finds the overall results of Ameren Missouri reasonable and consistent with cost-causation principles, while finding that "Staff's study strays far afield of industry standard practices, ignores basic principles of cost-causation, and results in overall allocations that simply should not be relied on".[40] Like Ameren Missouri witness Hickman, Mr. Brown notes that the Staff's allocation methodologies include numerous examples of "new" methodologies that seem to increasingly shift toward the utilization of energy-based allocations for what are clearly demand-related costs, which tends to systemically shift costs from the residential class to the larger classes in a manner that does not reflect the underlying cost causation of the system.[41]

[39] Id. at p. 6, ll. 14 – 17.

[40] Exhibit 38, Surrebuttal Testimony of Craig Brown, p. 4, ll. 1-5.

[41] Exhibit 38, Surrebuttal Testimony of Craig Brown, p. 4 ll. 10 – 18.

Mr. Hickman concludes that the Staff's CCOS study should be rejected by the Commission in this case due to Staff's use of "non-standard and technically inaccurate allocation methodologies that arbitrarily shift costs from small to large customers without supporting cost-causation".[42]

The Commission recently ruled on Ameren Missouri's CCOSS in its Report and Order in Case No. ER-2021-0240, finding that "For purposes of this case, the Commission finds Ameren Missouri's class cost of service study offers a reasonable estimation of class cost of service".[43] The fundamental way that Ameren Missouri's infrastructure is used to serve its customers has not changed in the 15 months since the Commission found the Company's CCOSS to be reasonable, nor has the Company changed its CCOSS approach. Despite the lack of change, Staff continues to aggressively modify its approach, as highlighted by Table TH-1.[44] Ameren Missouri's CCOSS and Staff's CCOS cannot both be viewed as reasonable outcomes.[45]

In addition to the serious flaws pointed out by MIEC Brubaker discussed above, the following serious flaws in Staff's CCOSS and association positions, include but are not limited to the following:

- Inconsistency of rate recommendations against national industry averages, driven by CCOSS results;
- Inconsistency of CCOSS results recommended by Staff over the three most recent Ameren Missouri general rate cases; and

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[42] Id. at p. 16, ll. 2 – 6.

[43] Exhibit 37, Hickman Surrebuttal at p. 16, ll. 15 – 18.

[44] Id. at p. 16, ll. 21 -- 22.

[45] Id. at p. 17, ll. 1 – 3.

- Fundamental flaws with apparent incomplete or inequitable distribution and production allocators.[46]
- Erroneous use of the NARUC manual to support the use of an energy allocator for the allocation of distribution related investments, including 10 individual quotations of the NARUC Manual containing 24 references to demand-related and 29 references to customer-related. At no point did any of Staff's quotes mention energy as a basis for allocating distribution investment.[47]
- Double counting of energy relative to wind investment. Staff observes that a certain amount of customers' energy needs are served by wind investment but fails to remove that energy that was served by the wind investment from the remaining production plant allocators. This results in a double counting of energy relative to wind investment and then again against the remaining investment allocation using the A&E 4 NCP method.[48]
- Allocation methodologies for production and distribution demand costs that are outside of industry-accepted standards and are based on new unsupported allocation methods based on energy instead of demand for demand-related cost. Staff's approach fails to reflect cost-causative factors that are critical to achieving the goals of a CCOS study.[49]
- Unreasonable requests for a non-existent level of detail for fixed asset accounts on a voltage- and customer-specific basis despite the fact that Ameren Missouri's CCOSS

[46] Id. at p. 17, ll. 7 - 12.

[47] Exhibit 37, Surrebuttal Testimony of Thomas Hickman, ll. 1 – 8.

[48] Id. at p. 16, ll. 3 -- 13.

[49] Exhibit 38, Surrebuttal Testimony of Craig Brown, p. 3, ll. 5 – 9.

is consistent with similar electric utilities[50]. MIEC witness Brubaker and Ameren witness Brown both conclude based on their extensive experience in the field of CCOS that the level of detail used by Ameren Missouri is consistent with the level of detail tracked by most utilities, while the level of detail requested by the Staff is excessive and not tracked by most utilities.[51]

- Inappropriate allocation of demand-related costs on an energy basis. Staff's CCOSS separates out "Type 2 generation", which is defined as having little or no variable costs, with the dispatch often limited by weather conditions or other factors beyond the control of the utility, or generally wind and solar assets. This approach which Staff refers to as "Partial Energy Weighting" is not an accepted way of allocating production demand costs and is effectively an energy allocation of costs that are classified as demand.[52]

Based on these serious flaws and inconsistencies, the Commission should reject the Staff's extreme and unreasonable CCOSS and adopt MIEC's CCOSS of MIEC to establish rates in this case, or in the alternative maintain its use of Ameren Missouri's CCOSS.[53]

Regarding Staff's specific criticisms of Ameren's distribution system data and recordkeeping, Staff seems to think that the inability to identify the costs associated with specific distribution lines and other delivery equipment renders Ameren's studies imprecise and unreliable. While the records probably could be made more precise, this would not add useful or meaningful information regarding the accuracy of cost allocation studies. Knowing the exact cost (and depreciated value) of a specific 44kV line running from Point A to Point

[50] Id. p. 2, ll. 20 – 22.

[51] Exhibit 38, Brown Surrebuttal at p. 4, 20 – p. 5, l. 5.

[52] Brown Surrebuttal at p. 10, l. 20 – p. 11, l. 6.

[53] Exhibit 37, Hickman Surrebuttal, p. 17, ll. 13 – 14.

B as compared to the average cost per mile of all 34 kV lines is not particularly meaningful when rates are set on the basis of general categories of customers and voltage level. Customers taking service at 34 kV are allocated a share of the costs of 34 kV and higher voltage equipment. Rates are designed to serve all 34kV customers as a class, without regard to their specific geographic location, or the age of the facilities specifically providing service. In other words, unless rates were to be set separately for each individual customer, the added information would be of no value. [54]

As noted by MIEC witness Brubaker, based on his 50 plus years of experience in reviewing class cost of service studies performed by numerous electric utilities in 34 regulatory jurisdictions, the level of detail behind Ameren's class cost of service study is generally consistent with the level of detail and practices of other electric utilities.[55]

Ameren witness Hickman's surrebuttal testimony illustrates what the effect would be of fully embracing Staff's CCOS theories by analyzing Ameren Missouri's current rates, by customer type, to compare to national average rates. He then shows how Ameren Missouri's rates, by those same customer types, would compare to national averages if Staff's CCOS were the basis of those rates. His illustration shows that, following the Staff's CCOS, Ameren Missouri would have overall average rates over 10 percent below the national average, but industrial rates that are 10 percent above the national average, and residential rates more than 20 percent below the national average. That 30 percent differential between the relationship of industrial rates and residential rates to the national averages demonstrates that Staff's attempts to take Missouri regulation far outside the mainstream would also represent a significant negative impact on large industrial customers (employers) in the

[54] Exhibit 501, Brubaker Rebuttal at p. 13, ll. 1 - 12.

[55] Id. at p. 13, ll. 13 - 16.

service territory that would ultimately have the potential to discourage economic development, and potentially drive existing employment out of the state. As stated by Ameren Missouri witness Wills, "It is time to recognize that enough is enough when it comes to Staff's misguided attempts to turn the concept of CCOS on its head".[56] The Commission should find that the generally similar CCOS approaches of MIEC and Ameren are reasonable and reject Staff's CCOSS. Staff's request for additional data should be addressed in the Non-residential rate design collaborative after conclusion of this case.

Staff erroneously and baselessly claims that the MISO market has made traditional cost allocation methodologies (i.e., the 4 NCP A&E method) irrelevant. As noted by Ameren Missouri witness Wills, this claim by Staff is a "gross exaggeration".[57] MISO does operate an integrated wholesale energy and capacity market that the Company participates in (and has since 2005), and the advent of the MISO market had significant operational ramifications for the Company and utilities in the region.[58] But its biggest impact was not that it fundamentally altered the economic paradigm of vertically-integrated electric utilities, as Staff's CCOS comments would suggest, but simply that it increased efficiency and transparency of wholesale market transactions and mechanisms that have existed for years.[59] Prior to the advent of the MISO market, Ameren Missouri would still dispatch its units in a manner that was informed by wholesale market prices.[60] If the market could provide energy cheaper than the Company could produce it, the Company would back down the production

[56] Exhibit 41, Surrebuttal Testimony of Steve Wills, p. 27, ll. 1-2

[57] Id. at p. 27, l. 8.

[58] Id. at p. 27, l. 8 – 11.

[59] Id. at p. 27, ll. 12 - 14.

[60] Id. at p. 27, ll. 14 – 16.

from the more expensive generating unit(s), and purchase energy from the market.[61] If the Company could produce excess energy at a cost lower than the prevailing market price of energy, then it would dispatch up to its unit(s) above the level needed to meet its own load obligations and sell the excess energy off-system.[62] Those exact same dynamics exist with MISO -- except that, as the market is more efficient and transparent in achieving these outcomes when a central agent publishes prices and accepts standardized bids and offers to buy and sell energy, and even sends dispatch instructions to the unit operators consistent with the offers that cleared in the market.[63] Yet Staff suggests that the existence of MISO somehow suddenly rendered the traditional economic paradigm of utility cost allocation irrelevant.[64] Contrary to Staff, the MISO market's improved transparency makes it very clear what Ameren Missouri's marginal cost of energy and capacity are, but it does little if anything to change the embedded cost of Ameren Missouri's generation fleet that has been constructed to meet. customers' energy and capacity requirements – and the embedded costs that serve as the basis of the rates to be established in this case.[65] As Ameren Missouri witness Hickman describes further in his rebuttal testimony, traditional production cost methodologies like 4 NCP A&E are just as relevant today and they have been historically. This is especially true of methodologies such as 4 NCP A&E that already inherently recognize that the Ameren Missouri's generation fleet is designed to meet both the energy and capacity needs of Ameren Missouri's customers.[66]

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[61] Id. at p. 27, ll. 8 – 11.

[62] Id. at p. 27, ll. 16 – 18.

[63] Id. at p. 27, ll. 18 – 20.

[64] Id. at p. 28, ll. 1 – 2.

[65] Id. at ll. 3 – 7.

[66] Id. at ll. 7 –12.

As observed by Ameren Missouri witness Steve Wills, rate design can be viewed as an extension of the cost allocation process. The same principle of cost causation is at work in the design of rates, which effectively determines the allocation of costs among customers within a class. Generally, reflecting costs in the rate element (e.g., customer charge, demand charge, energy charge) that matches the cost classification (e.g., customer-related costs, demand-related costs, energy-related costs) from the CCOSS, transmits the cost structure of the utility as a price signal to customers on their bills. An appropriate determination of the customer charge would include these additional customer-related costs from the CCOSS.[67]

Consistent with the appropriate alignment of rate design with cost-causation, MIEC witness Brubaker and MECG witness Chriss both provide testimony opposing Staff's proposals in this case to make significant changes to non-residential rate plans, including the introduction of a time-of-use "overlay" on each of the non-residential rate schedules.[68] Ameren Missouri witness Wills fully agrees with witness Mr. Brubaker:

"The amount of time allowed for customers to consider potential impact and offer counterproposals is completely inadequate. If Staff wishes to explore further refinements to rates applicable to large customers, then such changes should be considered in a separate proceeding, or there should be a collaboration among Staff, Ameren Missouri and interested parties that would take place between now and the next rate case filing. Only by this approach (which is followed by Evergy) will all parties have a fair and reasonable opportunity to consider impacts and be heard on their concerns and solutions." [69]

[67] Wills Rebuttal, p.17, ll. 4 – 12.

[68] Exhibit 41, Surrebuttal Testimony of Steve Wills, p. 23 at ll. 3 – 16.

[69] Exhibit 351, Rebuttal Testimony of Maurice Brubaker, p. 12, l. 18 – p. 13, l. 2.

Like MIEC witness Brubaker, MECG witness Chriss recommends that Staff's proposal be deferred to a future collaborative process to evaluate non-residential rate designs. He also highlights a specific issue with Staff's proposed rate that he says could be more fully vetted in such a process and supports vetted in a future collaborative process. Witness Chriss highlights that Staff seems to focus almost exclusively on market based marginal rates – MISO LMPs – to define what makes up a cost-based TOU rate. He mentions the fact that as a vertically integrated utility, the Company's embedded costs are an appropriate basis for setting rates. This key issue shows up in multiple places in Staff's analysis with respect to rate design and class cost of service. Staff seems content to inappropriately set aside traditional embedded cost principles in examining production cost allocation in the CCOS process in and in TOU rate design, in favor of focusing almost exclusively on marginal costs associated with the Company's involvement in MISO. Staff went so far as to claim – with respect to CCOS – that the Company's participation in MISO has rendered traditional production cost allocation methodologies irrelevant.[70] Ameren Missouri witness Wills describes this perspective as a "gross exaggeration".

Similarly, when Staff suggests that the Ameren Missouri's TOU rates fail to reflect cost simply because they do not exclusively reflect whole energy cost differences between different time periods, this is a gross over-simplification of the interplay of marginal and embedded cost principles that influence the structure of rates for retail electric service. In summary, Staff's suggestion should be rejected.[71]

Staff recommends that all Non-residential rate schedules have a major overhaul in this case, and then have a completely new major overhaul in the Company's next general rate

[70] Exhibit 41, Surrebuttal Testimony of Steven M. Wills p. 24, ll. 6 – p. 8.

[71] Id. at ll. 13—17.

case to implement different rate designs that override the new rate structures that would be implemented in this case.[72] Overhauling non-residential rates, including making the attendant billing system charges and engaging in the appropriate communications to notify customers of the change, in two consecutive rate cases in a manner where the two overhauls do not build on each other, but each go in completely different directions with the rate design, and as described by Ameren Missouri witness Steve Wills "is about as administratively inefficient, and customer unfriendly, of a proposal I can imagine".[73]

The Commission has already ordered the Company to look at updating its Non-Residential rate structures in its first electric rate review that will take effect in 2025 or later.[74] That timing was selection for a good reason. It is expected to be the first rate review that will occur after full deployment of Ameren Missouri's AMI meter system.[75] The data being collected from AMI meters will allow a more robust analysis of rate structures and the potential bill impacts that the AMI meters may cause for customers, and the existence of the new meters will facilitate billing more complex time varying rates that presumably may be proposed by the Company or other parties in that case.[76] Staff appears to recognize that the next case is the right opportunity to full evaluate new Non-residential rates, and yet somehow suggests that Ameren Missouri should also fundamentally alter its billing paradigm in this case leading up to that change. [77] As described by Ameren witness Wills, "To overhaul the Non-residential rates twice in quick succession would be utter waste of significant resources

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[72] Exhibit 40, Rebuttal Testimony of Steve M. Wills, p. 10, ll. 4 - 12.

[73] Id. at p. 10, ll. 9-14.

[74] Wills Rebuttal, p. 10, ll. 15 – 16.

[75] Id. at p. 10, ll. 17-18.

[76] Id. at p. 10, l. 18 – p 11, l. 2.

[77] Id. at p. 11, ll. 2- 4.

for short-lived rates".[78] Ameren Missouri notes that such a project could take as long as 14 months, and include hundreds of hour of labor and 4 months to complete all the requirements of gathering, programming, implementation and testing of new rate structures.[79] Additionally, Ameren Missouri employees would need internal communication materials and training to respond to inquiries from affected customers, and customers would need to be informed and educated about the rate changes. Given the diversity of Non-residential customers ranging from small commercial customers, to large corporate chains like Walmart, to huge energy-consuming factories like those operated by MIEC members, the communication tactics and channels would need to be developed and would be much challenging and more nuanced than that needed for Residential customers.[80] The extreme administrative inefficiency of doing this twice in two consecutive cases should be given weight by the Commission in evaluating Staff's proposal.[81]

CONCLUSION

The alternative scenarios presented in MIEC witness Brubaker's Schedules MEB-COS-5 and MEB COS-6, along with MIEC Hearing Exhibit 353 prepared by MIEC witness Brubaker, show the Commission with a range of options to move rates toward cost of service. The MIEC recognizes that cost of service is the starting point for setting just and reasonable rates, and the Commission has broad discretion to consider other factors such as gradualism, economic growth, job retention, rate stability, revenue stability, public acceptance, simplicity and ease of administration.[82] The MIEC urges the Commission to

[78] Id. p. 11, ll. 4 - 6

[79] Id. at p. 11, ll. 17-20.

[80] Wills Rebuttal p. 12, ll. 1 – 9.

[81] Id. at ll. 7 – 9.

[82] *Id*. at page 36.

move as fully as possible toward cost-based rates, which would benefit Missouri's economy by enabling customers to better predict and manage electricity costs. Movement toward cost-of-service in this case would make rates more equitable and help Missouri to attract and retain jobs to the benefit of Missouri's economy as a whole.

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 to all parties on the Commission's service list in these cases.

/s/ Diana M. Plescia