BEFORE THE PUBLIC SERVICE COMMISSION
STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Annual Revenues for Electric Service.	))))	**File No. ER-2021-0240**

MECG STATEMENT OF POSITIONS

COMES NOW the Midwest Energy Consumers Group ("MECG") and for its Statement of Positions on the remaining issues in this case[1] respectfully provides as follows:

25. Class Cost of Service, Revenue Allocation and Rate Design (Electric)

A. How should production costs be allocated among customer classes within a Class Cost of Service Study?

General Position: Given its extensive reliance on the energy allocator for the allocation of fixed production costs and thus its failure to recognize the capacity value of all generation units, the Commission should reject Staff's class cost of service study. Instead, the Commission should rely on the MECG, MIEC, or Ameren studies, which rely on the Average & Excess ("A&E") fixed production cost allocator, for purposes of allocating any rate increase in this case.

Relevant Testimony:

Exhibit 750, Chriss Direct, pages 10-21
Exhibit 500, Brubaker Direct, pages 22-30.
Exhibit 30, Hickman Direct, pages 18-20.

Detailed Discussion: During the 2021 legislative session, the General Assembly enacted Section 393.1620. That statute, enacted primarily in response to Staff's ever changing method for allocating fixed production costs, mandates that the Commission only consider class cost of service studies that "allocate the electrical corporation's production plant costs from nuclear and fossil generating units using the average and excess method ["A&E"] or one of the methods of assignment or allocation contained within the National Association of Regulatory Commissioners 1992 manual or subsequent manual."[2]

[1] On November 24, 2021, the parties submitted a Unanimous Stipulation and Agreement. That Stipulation provided a resolution of all revenue requirement issues as well as the settlement of several other issues. To date the Commission has not yet approved that Stipulation. Recognizing the pendency of that Stipulation, MECG has refrained from preparing a Statement of Position on those settled issues. That said, in the event that the Commission rejects that Stipulation and decides to independently decide each of those issues, MECG reserves the right to take positions as reflected in the various pieces of prefiled testimony in this case.

[2] Section 393.1620.2.

There was several class cost of service studies presented in this case. Each of those studies largely complies with Section 393.1620.[3] Specifically, MECG, MIEC and Ameren each presented studies that rely on the A&E methodology not only for the allocation of the "nuclear and fossil generating units" required by the statute, but also for the allocation of renewable resources.

On the other hand, Staff relied upon an amalgam of allocation methodologies. The key point, as reflected in the following quote, is that Staff relied exclusively on the energy allocator for all renewable generation.

> Staff segregated the various Ameren Missouri generating facilities into 10 categories: Nuclear; coal; combustion turbine; Taum Sauk; Osage; Keokuk; Wind; Landfill; General Solar; and Community Solar. Staff then calculated the revenue requirement associated with the fixed costs of each of these categories of generating units (see Staff Report, pages 37-39). Staff then considered a range of allocation methodologies, including variants of single peak; multiple peak; Average & Excess; and Peak & Average methodologies for the nuclear; coal; combustion turbine; Taum Sauk and Osage generation categories. ***<u>For the other generation categories (Keokuk; Wind; Landfill; and General Solar), Staff relied only on the energy allocator under the misplaced premise that these generation facilities exist simply to provide Renewable Energy Certificates ("RECs") and energy and do not provide any capacity benefit (see Staff Report, page 42)</u>***. Finally, Staff allocated the fixed costs associated with the Community Solar category entirely to the Community Solar customers.[4]

Staff's exclusive reliance on the energy allocator for renewable generation is misplaced. As Mr. Brubaker points out, the reliance on the energy allocator fails to recognize that renewable generation provides not only energy, but also the capacity needed to meet Ameren's system peak demand.

> To effectively and cost-efficiently serve the power requirements of its customers, electric utilities invest in and/or procure through purchased power agreements a variety of generation resources that have different characteristics. A generation resource portfolio typically includes baseload facilities that are designed to operate

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[3] MECG suggests that each of the class cost of service studies "largely" complies with Section 393.1620 because, while Ameren utilizes the Average and Excess methodology expressly recognized by the statute, in that Ameren does not use each class' coincident peak for those months in which Ameren experienced its system peaks. Instead, Ameren used non-coincident peaks. "Upon examination of the calculation of Ameren's proposed allocator, it appears that allocator differs slightly from that specified in Section 393.1620.1(1) RSMo, in that the months used for the 4NCP in the A&E 4NCP are "determined…for the four months with the highest system peak loads." As shown in Exhibit SWC-4 row (9), the four months with the highest system peak loads are February, June, July, and August, but in rows (10) through (14) the class NCPs used for the calculation of the allocator are, depending on the class, from January, March, April, May, June, July, August, and September." Exhibit 750, Chriss Direct, page 18. As reflected in MECG's testimony, this shortcoming is not result in the calculation of class A&E allocators that are meaningfully different. Instead, MECG simply raised this issue out of an abundance of caution and to avoid the possibility that parties would seek to reject the A&E analyses in this case on the basis that the studies did not comply with the newly enacted statute.

[4] Exhibit 501, Brubaker Rebuttal, pages 3-4 (emphasis added).

> most of the time, and which have (in a relative sense) higher fixed costs, and lower variable cost. At the other end of the spectrum of characteristics are peaking plants (whose use is expected to be needed only infrequently for unexpected needs and for peaking capacity) that have (in a relative sense) relatively higher variable costs and relatively lower fixed costs. . . Recognizing that all of these facilities are part of an overall generation resource portfolio designed to serve the overall power requirements of a utility's customers at the lowest overall reasonable cost, and that all provide capacity, the generally accepted method is to allocate the fixed costs associated with all of these facilities on the basis of an appropriate measure of customer demand, and to allocate all of the variable costs to customer classes on the basis of relative class kWh requirements.[5]

Ameren agrees. "A cost allocation methodology that gives weight to both class peak demands and class energy consumption (average demands) is required to properly address both of the above considerations associated with capacity planning. The A&E methodology gives weight to both of these considerations by its inclusion of both average class demands, which are kilowatt hours divided by total hours in the year (8,760 hours), and the excess NCP demands of each class."[6]

The motivation underlying Staff's exclusive reliance on the energy allocator is apparent – it shifts costs away from low load factor / less efficient customer classes that use less energy per kW of demand (i.e., residential class) to high load factor / more efficient customer classes that use more energy per kW of demand (i.e., large general service, small primary and large primary classes). The Commission should recognize that all generating units provide a measure of capacity value and reject Staff's misplaced attempt to allocate the costs of renewable generation on class energy usage.[7]

The results of the Ameren, MIEC, and MECG studies are all relatively aligned. The amount of fixed production plant costs allocated under each of these studies is as follows:

	Ameren	**MIEC**	**MECG**
Residential	52.53%	52.5%	52.76%
SGS	10.93%	10.9%	10.89%
LGS / SP	28.71%	28.7%	28.77%
LP	7.50%	7.5%	7.24%
Company – Owned Lighting	0.34%	0.2%	0.33%
Customer – Owned Lighting	0.34%	0.1%	0.33%

Source: Exhibit 750, Chriss Direct, page 21; Exhibit 500, Brubaker Direct, Schedule MEB-COS-3A.

[5] *Id.* at page 8.
[6] Exhibit 30, Hickman Direct, page 19.
[7] There are numerous other problems underlying Staff's class cost of service study. As detailed in Mr. Brubaker's rebuttal testimony (Exhibit 501), Staff used inappropriate allocators for the allocation of general overhead costs (pages 9-11) and plant in service account (PISA) costs (pages 11-12). These problems inherent in Staff's methodology provide additional justification, in addition to Staff's overreliance on the energy allocator, for the rejection of Staff's study.

The reasonableness of the A&E methodology is best exemplified by comparing the A&E results to allocations produced by the other methodologies recognized under the NARUC manual.

	Residential	SGS	LGS / SP	LP	Company-Owned Lighting	Customer-Owned Lighting
A&E 4 NCP	52.5%	10.9%	28.7%	7.5%	0.2%	0.1%
A&E 2 NCP	52.5%	11.1%	28.7%	7.4%	0.2%	0.1%
A&E 1 NCP	52.6%	11.1%	28.6%	7.4%	0.2%	0.1%
4 CP	52.9%	10.5%	29.0%	7.5%	0.0%	0.0%
2 CP	53.4%	10.9%	28.4%	7.4%	0.0%	0.0%
1 CP	53.3%	10.9%	28.6%	7.2%	0.0%	0.0%
4 NCP	52.3%	10.9%	28.7%	7.5%	0.4%	0.2%
2 NCP	52.7%	11.2%	28.4%	7.2%	0.3%	0.2%
1 NCP	52.9%	11.1%	28.2%	7.2%	0.3%	0.2%

Source: Exhibit 500, Brubaker Direct, Schedule MEB-COS-3A

Given the reasonableness of the A&E methodology, the fact that Staff's methodology is fundamentally flawed, the Commission should adopt any of the A&E studies presented in this case.

B. How should the non-fuel, non-labor components of production, operation and maintenance expense be classified and allocated among customer classes?

General Position: The $69 million of non-fuel, non-labor costs of production and O&M should be allocated on the same basis that the underlying plant is allocated – specifically using the A&E methodology. These costs are incurred on the basis of time and do not vary with the electricity generated. Therefore, the use of the energy allocator should be rejected.

Relevant Testimony: Exhibit 500, Brubaker Direct, pages 34-35.

Detailed Discussion: In its cost of service study, Ameren recommends that $69 million of 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. In its rebuttal testimony, however, MIEC pointed out that these costs are fixed and are incurred regardless of the amount of electricity generated at the generating units.

> It is my position that the vast majority of these costs do not vary in any appreciable way with the number of kWh generated, but occur primarily as a function of the existence of the plants, the hours of operation and the passage of time. In fact, Ameren Missouri schedules the maintenance on its coal and nuclear generation units on a "passage of time" basis, not on a "kWh generated" basis. I believe the 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 as the "expenses follow plant" basis.[8]

[8] Exhibit 500, Brubaker Direct, page 34.

C. How should any rate increase be allocated to the several customer classes?

General Position: The Commission should allocate the authorized rate increase in this case based upon the measured approach suggested in the testimony of MECG witness Chriss (Exhibit 750, Chriss Direct, pages 27-28). Such an approach reflects gradualism while also taking definitive steps to eliminate the long-lingering residential subsidy inherent in Ameren rates.

Relevant Testimony: Exhibit 750, Chriss Direct, pages 21-28.
Exhibit 500, Brubaker Direct, pages 36-41.

Detailed Discussion: As reflected in its response to Issue 25A, MECG encourages the Commission to reject Staff's class cost of service study in this case and utilize one of the studies that rely upon the A&E methodology. Once eliminated, the Commission should rely on either the results of Ameren or MIEC's complete quantification of class subsidies to drive its decision on revenue allocation. The following table shows the earned return from each class under each of the completed studies.[9]

	Ameren		MIEC	
	Earned Return	Rate of Return Index	Earned Return	Rate of Return Index
Residential	3.10%	0.65	3.44%	0.72
SGS	5.15%	1.08	5.01%	1.05
LGS / SP	7.35%	1.54	6.83%	1.43
LP	7.70%	1.62	7.27%	1.53
Company-Owned Lighting	9.02%	1.89	7.94%	1.67
Customer-Owned Lighting	-4.57%	(0.96)	-2.05%	-43
Total Company	4.76%	1.00	4.77%	1.00

Source: Exhibit 750, Chriss Direct, Schedule SWC-7; Exhibit 500, Brubaker Direct, Schedule MEB-COS-5.

The results of these studies demonstrate two undeniable facts. ***First***, under both studies, the residential class revenues are producing a rate of return (3.10-3.44%) that is well below Ameren's system rate of return (4.76%). ***Second***, each of the general service classes (SGS, LGS / SP, and LP) are providing revenues that produce a rate of return well above the Ameren system rate of return. Specifically, the LGS / SP class is providing a rate of return of 6.83% - 7.35% at a time when Ameren is earning a total return of 4.76%. Thus, it is apparent that these general service classes are all paying rates above cost of service while the residential class is paying rates below cost of service. Clearly then, a residential subsidy is inherent in Ameren's rates.

[9] While MECG witness Chriss provided the results of his A&E methodology, he did not carry those results through to a complete class cost of service study. As such, there are no independent results to show the quantification of the residential subsidy. Instead, his A&E calculation supports the reasonableness of Ameren's class cost of service study and Ameren's quantification of the residential subsidy.

The existence of a residential subsidy is not a recent development. As Mr. Chriss details, "As shown in Table 5, LGS and SP rates have provided a rate of return above their cost of service levels in every rate case back to and including the Company's 2007 rate case. In total, as shown in Table 1 earlier in this testimony, this has resulted in LGS and SP customers paying rates well in excess of the Company's cost to serve them since 2007. As such, rate relief is long overdue."

Case	LGS / SP Rate of Return (%)	Total Missouri Rate of Return (%)	Rate of Return Index Value
ER-2007-0002 (LGS)	5.86%	2.74%	2.14
ER-2007-0002 (SP)	4.47%	2.74%	1.63
ER-2008-0318	7.01%	4.06%	1.73
ER-2010-0036	6.12%	1.89%	3.24
ER-2011-0028	8.26%	4.59%	1.80
ER-2012-0166	6.32%	2.89%	2.19
ER-2014-0258	7.57%	4.44%	1.71
ER-2016-0179	9.73%	5.41%	1.80
ER-2019-0335	11.35%	7.37%	1.54
Present Case	7.35%	4.76%	1.54

Source Exhibit 750, Chriss Direct, page 23. (Note: Prior to 2007 Ameren had not had a general rate case for over 20 years. Therefore, the residential subsidy is likely to have extended back for many years, if not decades, prior to the 2007 rate case).

The magnitude of the residential rate increase necessary to eliminate the residential subsidy and get residential rates at cost of service is material. Specifically, both MIEC and Ameren have asserted that the residential class would require a revenue neutral increase of 7.8% or 7.32% respectively, prior to the 8.81% increase envisioned by the pending Unanimous Stipulation.[10] In contrast, the Large General Service / Small Primary class would require a revenue neutral reduction of 9.7% or 9.14% respectively prior to the increase reflected in the stipulation.

	MIEC		**Ameren**	
	$$ (millions)	**%**	**$$ (millions)**	**%**
Residential	$99,254	7.8%	$93,202	7.32%
Small General Service	($3,565)	-1.3%	($4,258)	-1.55%
Large General Service / Small Primary	($70,674)	-9.7%	($66,501)	-9.14%
Large Primary	($20,385)	-10.8%	($17,855)	-9.47%
Company-Owned Lighting	($6,160)	-17.3%	($6,183)	-17.35%
Customer-Owned Lighting	$1,530	53.7%	$1,594	55.96%

Source: Exhibit 750, Chriss Direct, page 24; Exhibit 700, Brubaker Direct, Schedule MEB-COS-5.

[10] "Revenue neutral refers to the changes necessary to bring each class to cost of service assuming no overall change in the utility's revenues." Exhibit 750, Chriss Direct, page 24.

Given the magnitude of the increase that would be required to completely eliminate the residential subsidy, MECG has proposed a gradual elimination of the subsidy. "If the Commission awards a revenue requirement increase lower than that proposed by the Company, MECG recommends the Commission take significant steps to bring the rates paid by SGS, LGS, SP, and LPS closer to their cost of service-based levels."[11] Specifically, MECG proposes a two-step revenue allocation methodology which would: (1) apply one-half of the difference between the revenue increase initially requested by Ameren and the amount actually authorized by the Commission towards the residential subsidy and then (2) apply any authorized increase on an equal percentage basis.[12] In his testimony, Mr. Chriss provided an illustrative example. Showing a great deal of foresight, Mr. Chriss' illustration is based upon an overall increase of $221 million and would lead to "approximately a 41 percent movement towards cost of service-based rates".[13] The actual increases, after applying the two-step process set forth by Mr. Chriss would be as follows:

	Revenue Change		**Subsidy Reduction**
Customer Class	**($)**	**(%)**	**(%)**
Residential	$131,951,362	10.4%	
Small General Service	$26,743,055	9.8%	41
Large General Service	$34,010,216	6.7%	41
Small Primary Service	$14,812,832	6.7%	41
Large Primary Service	$12,351,893	6.6%	41
Company-Owned Lighting	$1,144,501	3.2%	41

Source: Exhibit 750, Chriss Direct, page 28.

Thus, under MECG's proposal, the residential class would receive a 10.4% rate increase in this case. This compares to the initial 11.97% increase initially requested by Ameren.

Given the long standing nature of the residential subsidy, as well as the economic implications of the large commercial / industrial customers continuing to pay rates that are 10-11% above cost of service, MECG recommends that the Commission adopt its revenue allocation proposal.

F. Should the Commission approve MECG's proposed shift to increase the demand component for Large General Service and Small Primary Service and decrease energy charges?

General Position: The Commission should increase the summer and winter demand charges for LGS and SP by three times the percent class increase.

Relevant Testimony: Exhibit 750, Chriss Direct, pages 29-37, 46.
Exhibit 751, Chriss Surrebuttal, all

[11] Exhibit 750, Chriss Direct, page 26.
[12] *Id.* at pages 27-28.
[13] The increase envisioned under the pending Unanimous Stipulation is $220 million. Therefore, the illustrative example is almost exactly the revenue allocation that would be applicable under MECG's revenue allocation proposal.

<u>Detailed Discussion</u>: In order to avoid intraclass subsidies it is important that the Commission establish rates which collect costs in the manner in which they are incurred. Thus, fixed costs should never be collected on a per kwh. Instead these costs should be collected through a demand charge on a per kW basis. Collecting such fixed costs through energy charges on a per kWh basis would lead to high load factor customers in a particular class subsidizing low load factor customers in that class. Under such a rate design, energy costs, which are incurred on a variable basis depending on the amount of electricity generated, would then be the <u>only</u> costs that are collected through energy charges on a per kWh basis.[14] By collecting costs through charges that reflect the manner in which costs are incurred sends proper price signals regarding the actual cost of building generation as well as the variable cost of generating the electricity.

Ameren's LGS / SP rate schedules include both demand charges and energy charges. So while the mechanisms exist to collect costs in the manner in which they are incurred (i.e., fixed costs collected on a per kW basis and variable costs collected on a per kWh basis), the "LGS and SP rates do not currently reflect the underlying cost of serving those classes. That is to say that demand charges do not collect all demand-related costs. Instead a significant portion of these demand-related costs are collected on a variable basis through the energy charges."[15] This fact is best demonstrated by the fact that, while 77% of costs are demand-related, only 14% of LGS revenues and 9.6% of SP revenues are collected through demand costs."[16] "Clearly then LGS and SP rate components are sending incorrect price signals."[17]

Component	**COSS Results**		**LGS Revenue Requirement**		**SP Revenue Requirement**	
	($000)	**(% of Total)**	**($000)**	**(% of Total)**	**($000)**	**(% of Total)**
Demand	$565,531	76.7	$79,558	14.0	$23,625	9.6
Energy	$153,373	20.8	$474,667	83.6	$220,289	89.3
Customer	$18,762	2.5	$13,563	2.4	$2,903	1.2
Total	**$737,666**	**100**	**$562,180**	**100**	**$243,913**	**100**

Source: Exhibit 750, Chriss Direct, page 34.

Recognizing that 76.7% of the LGS / SP costs are demand-related, 76.7% of revenues should be collected through the demand charge. This would require a significant increase in the demand charges and a commensurate decrease in the energy charges. "Assuming the demand charge recovers 76.7 percent of base rate revenues, consistent with the Company's cost of service study results, the estimated cost of service-based $/kW demand charge for LGS for the summer period would be $27.42/kW and for the winter period would be $15.22/kW. Additionally, the cost of service-based energy charge for the summer period is $0.02228/kWh and for the winter period is $0.01316/kWh."[18]

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[14] Exhibit 750, Chriss Direct, pages 35-36.
[15] *Id.* at page 32.
[16] *Id.* at page 34.
[17] *Id.*
[18] *Id.* at 38.

The practical implication of such a rate design shortcomings is to subject Ameren "to under and overcollection of its revenue requirement due to fluctuations in customer usage. As such, issues such as weather and the economy will have a greater impact on the utility versus a rate design in which an appropriate amount of revenue requirement is collected through the demand charge.[19]"

Given the obvious problems in the LGS / SP rate design, Mr. Chriss recommends that the Commission "increase the demand and winter demand charges for the LGS and SP by three times the percent class increases."[20] Thus, if the LGS / SP rate class receives an overall increase of 6.7% (see page 7), then the demand charges should be increased by 20% with the remainder of the class increase being collected through the customer and energy charges.

G. Should the Commission approve MECG's recommendation to require the Company to present analyses of alternatives to the hours-use rate design by 2025?

Position: As previously indicated, the LGS / SP rate schedules include three declining block seasonal energy charges. Customers move through the declining energy charges based upon its load factor. Specifically, the rate in the first energy block is applicable for all usage less than 150 kWh / kW of billing demand. The second energy block rate is applicable for all usage between 150 – 350 kWh / kW, with the third energy block rate being applicable to all additional usage.[21] Mr. Chriss points out that this "hours-use structure is not the simplest manner as it requires the analyst to have more than a surface level understanding of the rate structure in order to understand the interplay of the energy rates and load factor, which is needed to perform bill analyses."[22] Interestingly, Ameren acknowledges that this rate design is "quite complex."

Given the complexity of the rate design and that most customers lack the sophistication to: (1) calculate their rates; (2) respond to price signals; and (3) take steps to reduce their electric bills, MECG suggests that the Commission order Ameren to begin to simplify its LGS / SP rates. Specifically, MECG recommends that the Commission "require Ameren to redesign LGS and SP as three part rates with unbundled demand charges and time varying energy charges and for all LGS and SP customers to be transitioned to those rates by 2025, which is my understanding of when the Company anticipates AMI will be fully deployed."[23]

Relevant Testimony: Exhibit 750, Chriss Direct, pages 30-31; 41-46.

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[19] *Id.* at 37.
[20] *Id.* at page 46. Ameren acknowledges that Mr. Chriss' recommendation is "directionally consistent with cost of service principles to the extent that the distribution demand-related costs are not currently fully reflected in the demand charge." Exhibit 18, Wills Rebuttal, page 53.
[21] *Id.* at page 29.
[22] *Id.* at page 41.
[23] *Id.* at page 45.

H. How should distribution costs be allocated or assigned among customer classes within a Class Cost of Service Study?

Position: In its Class Cost of Service Report Staff spends an inordinate amount of time criticizing Ameren's recordkeeping related to distribution facilities and costs. The thrust of Staff's criticism appears to be premised on its desire to "assign" instead of "allocate" distribution costs to specific customers and classes. Staff's approach represents a radical change from its approach in recent cases, as well as a repudiation of the concept of mass property accounting.

In his testimony, Mr. Brubaker rebutted Staff's criticism.

> While any set of records probably could be made more precise, the question is whether or not the added degree of precision would add useful or meaningful information and improve the accuracy of cost allocation studies. Knowing the exact cost (and depreciated value) of a specific 34 kV line running from Point A to Point 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 34 kV 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.[24]

Ultimately, Mr. Brubaker concludes, based upon his 50 years of experience reviewing class cost of service studies in 34 different regulatory jurisdictions, that the detail underlying Ameren's class cost of service study, including its accounting for distribution costs is "generally consistent with the level of detail and the practices of other electric utilities."[25]

I. What is the appropriate level of Rider B credits to be applied to the bills of customers providing their own substation equipment?

Position: Ameren currently has two rate schedules, Small Primary (Schedule 4M) and Large Primary (Schedule 11M), that assume that the customers take service at primary voltage levels. The customers taking service at this primary voltage level rely on Ameren to provide all substations in order to step down the voltage to that level. There are, however, certain customers that own their own substations and can take service at a higher voltage level (34 kV or higher). Since these customers provide their own substations, Ameren does not incur the costs for such substations. For this reason, it is necessary to back out the substation costs that are included in Schedule 4M and 11M. The mechanism to back out these substation costs is reflected in Rider B.

[24] Exhibit 501, Brubaker Rebuttal, page 13.
[25] *Id.*

> Where a customer served under rate schedules 4(M) or 11(M) takes delivery of power and energy at a delivery voltage of 34kV or higher, Company will allow discounts from its applicable rate schedule as follows:
>
> 1. A monthly credit of $1.14 / kW of billing demand for customers taking service at 34.5 or 69 kV.
> 2. A monthly credit of $1.35 / kW of billing demand for customers taking service at 115 kV or higher.[26]

In its Class Cost of Service Report, however, Staff recommends that the Commission "suspend" the applicability of the Rider B credits.

> Staff recommends that unless the costs of substation equipment that is dedicated to primary customer is specifically assigned to the bills of primary customers, that the discounts provided to primary customers under Rider B be suspended until Ameren Missouri provides the information necessary to include the cost of primary customer substations in the bills of primary customers (and such costs are so included).[27]

In his rebuttal testimony, Mr. Brubaker points out that Staff's recommendation "does not make sense"[28] and "defies logic."[29] Ameren's assessment of Staff's proposal was even more pointed. Specifically, Ameren describes Staff's recommendation as "stunning"; "punitive"; "objectively incorrect"; "reflects a fundamental misunderstanding of cost allocation"; based on Staff's "hyper-focus on direct assignment"; and premised on a "convoluted analysis."[30]

Ameren's witness Wills clearly explains why Staff's recommendation is "objectively incorrect."

> Customers who elect to install their own substations initially have to invest hundreds of thousands, or millions, of dollars that displace similar investments that the Company otherwise would have to make. They also bear the on-going cost to operate and maintain those substations. There should be no doubt that the cost of serving these customers is meaningfully lower than the cost of serving similarly situated customers in the same rate class who have not made these initial and on-going investments on their own behalf and instead relied on the Company to make them. But without the credit provided for by Rider B, that difference in the cost of serving these customers would be completely ignored. This punitive change would be unfair to customers that made such significant investment decisions based on an understanding that they would receive these bill credits as a result of their efforts.[31]

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[26] Exhibit 501, Brubaker Rebuttal, Schedule MEB-COS-R-4.
[27] Exhibit 205, Staff Class Cost of Service Report, page 54.
[28] Exhibit 501, Brubaker Rebuttal, page 15.
[29] *Id.* at page 16.
[30] Exhibit 18, Wills Rebuttal, pages 1 and 22-27.
[31] *Id.* at page 23.

Mr. Wills continues on to point out why Staff's recommendation is "punitive" and the impact that suspending the Rider B credits will have on these customers that provide and maintain their own substations. "The removal of these discounts would increase the SPS customers' and LPS customers' bills on average by an estimated 4.4% and 3.3% respectively, before consideration of any other rate increase granted in this case."[32]

Recognizing that Staff's recommendation "defies logic" and is "objectively incorrect", the Commission should reject the recommendation to suspend the Rider B credits.

[32] *Id.* at page 23.