

*Exhibit No.:*  
*Issue(s):* *Tracker, Class Cost of  
Service Rate Design*  
*Witness:* *Sarah L.K. Lange*  
*Sponsoring Party:* *MoPSC Staff*  
*Type of Exhibit:* *Rebuttal Testimony*  
*Case No.:* *ER-2022-0337*  
*Date Testimony Prepared:* *February 15, 2023*

**MISSOURI PUBLIC SERVICE COMMISSION**

**INDUSTRY ANALYSIS DIVISION**

**TARIFF/RATE DESIGN DEPARTMENT**

**REBUTTAL TESTIMONY**

**OF**

**SARAH L.K. LANGE**

**UNION ELECTRIC COMPANY,  
d/b/a AMEREN MISSOURI**

**CASE NO. ER-2022-0337**

*Jefferson City, Missouri  
February 2023*

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**SARAH L.K. LANGE**

**UNION ELECTRIC COMPANY,  
d/b/a AMEREN MISSOURI**

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1 Q. Could you summarize the specific recommendations presented in this  
2 testimony?

3 A. Yes.

- 4 1. Staff is not opposed to including the customer-owned segment of the lighting  
5 class for “Equal” treatment in the process recommended in my direct testimony,  
6 while holding the company owned-segment of the lighting class constant.
- 7 2. Staff recommends that the general request for “the authority to track revenues  
8 lost through this migration,” be denied as unreasonable. Further, the calculation  
9 Mr. Wills describes will calculate a value in excess of the bill savings  
10 experienced by Ameren Missouri customers. Finally, if the requested authority  
11 is granted, the appropriate customer group from which to seek recovery are those  
12 customers taking service on the highly-differentiated ToU rate plans.
- 13 3. Staff recommends that the Rider C factor be modified from 0.68% to 0.72%,  
14 assuming that there are not transformers on the Ameren Missouri system that  
15 are dramatically oversized, which may warrant creation of adjustment factors  
16 particular to the customers served by such transformers.
- 17 4. Staff recommends that the Commission order Ameren Missouri to complete a  
18 study of the cost of customer-specific assets associated with customers taking  
19 service at each major voltage level, including but not limited to: secondary low  
20 voltage single phase, secondary low voltage three phase, secondary high voltage,  
21 primary, subtransmission, and transmission.
- 22 5. Staff recommends transmission assets related to maintenance of voltage support  
23 due to the retirement of large synchronous generators be recorded to new  
24 subaccounts. Staff further recommends that customer and rate schedule  
25 characteristics related to draws of reactive demand be recorded for study for  
26 potential use in allocators, and for potential creation of determinants for  
27 customer billing.
- 28 6. Staff recommends that all customer charges for all residential rate plans be held  
29 at the current \$9.00 level, and that the Ultimate Saver and Smart Saver customer  
30 charges not be discounted.
- 31 7. If against Staff’s primary recommendation the customer charge for the Ultimate  
32 Saver plan is discounted relative to other rate plans, Staff recommends that a  
33 minimum demand charge equal to the difference in the customer charges be  
34 incorporated into the rate structure. This should be plainly disclosed in all  
35 relevant marketing and education materials.

36 **MISCELLANEOUS RATE STRUCTURE AND RATE DESIGN**

37 Q. Per Mr. Harding’s testimony at pages 9-10, Ameren Missouri requests to remove  
38 the 12(M) rate schedule from its tariff. Is Staff opposed to this request at this time?

1           A.     Staff is not opposed to elimination of this tariff in this case.

2           Q.     At pages 10 – 11 of Mr. Harding’s testimony, Ameren Missouri requests that the  
3 values for the monthly customer charge, Rider B credits, and Reactive Charge “need to remain  
4 consistent for SPS and LPS customers because these costs are effectively the same regardless  
5 of the customer class,” do you agree?

6           A.     No. While parties have often grouped these classes together in CCoS Studies  
7 because customers can switch between them, these are in fact different rate schedules with  
8 different requirements. Given the growth in the utility cost of service related to distribution  
9 rate base, the time has come to undertake more granular study of the costs caused by and  
10 properly allocated to customers on these rate schedules separately.

11          Q.     At the class level, Mr. Harding recommends essentially equal percent increases  
12 to Residential, Small General Service (SGS), Large General Service (LGS), Small Primary  
13 Service (SPS), Large Power Service (LPS), Metropolitan Sewer District and the company-  
14 owned Lighting classes, with a slightly higher increase to the customer-owned Lighting class.  
15 Do you agree with Mr. Harding’s lighting recommendations?

16          A.     I recommended lighting rates be held constant on the basis of my study which  
17 analyzed the Lighting Class as a whole and did not break out lighting by rate schedule. While  
18 I have many concerns with the reliability of the Ameren Missouri study, the differences within  
19 the lighting class between the lighting schedules is not an area I take issue with in this case.

20               Staff is not opposed to including the customer-owned segment of the lighting class for  
21 “Equal” treatment in the process recommended in my direct testimony, while holding the  
22 company owned-segment of the lighting class constant. The process provided in direct is  
23 reproduced below.

Rebuttal Testimony of  
Sarah L.K. Lange

1

	Residential	SGS	LGS	SPS	LPS	Lighting	Total
Treatment:	Equal	Equal	Above	Above+	Above+	Hold	Revenue Requirement Allocated
<b>Step 1</b>	\$ -	\$ -	\$ -	\$ 17,953,957	\$ 15,433,232	\$ -	\$ 33,387,188
(Under)/Over Contribution \$:	\$ (1,608,797)	\$ (14,625,213)	\$ (79,594,582)	\$ (39,841,835)	\$ (40,368,676)	\$ 10,170,067	
(Under)/Over Contribution %:	-0.12%	-4.60%	-12.48%	-13.41%	-15.43%	32.96%	
<b>Step 2</b>	\$ -	\$ -	\$ 20,938,143	\$ -	\$ -	\$ -	\$ 20,938,143
(Under)/Over Contribution \$:	\$ (1,608,797)	\$ (14,625,213)	\$ (58,656,440)	\$ (39,841,835)	\$ (40,368,676)	\$ 10,170,067	
(Under)/Over Contribution %:	-0.12%	-4.60%	-9.19%	-13.41%	-15.43%	32.96%	
<b>Step 3</b>	\$ 74,240,792	\$ 16,406,002	\$ 30,203,448	\$ 12,949,367	\$ 11,131,283	\$ -	\$ 144,930,892
(Under)/Over Contribution \$:	\$ 72,631,995	\$ 1,780,789	\$ (28,452,992)	\$ (26,892,467)	\$ (29,237,393)	\$ 10,170,067	
(Under)/Over Contribution %:	5.29%	0.56%	-4.46%	-9.05%	-11.18%	32.96%	
<b>Overall Recommended Increase \$:</b>	\$ 74,240,792	\$ 16,406,002	\$ 51,141,591	\$ 30,903,324	\$ 26,564,515	\$ -	\$ 199,256,223
<b>Overall Recommended Increase %:</b>	5.41%	5.41%	9.16%	12.91%	12.91%	0.00%	7.32%

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Q. Mr. Harding addresses several miscellaneous tariff items, for those for which

4

you are responsible, what is your recommendation?

5

A. Staff's positions are provided below:

6

1. 6(M) E&M Lighting updates, Sheet No. 59 – Staff does not oppose;

7

2. Removal of Unmetered Customer Charge from 2(M) Optional TOU rate, 19 Sheet No. 55 – Staff does not oppose;

8

3. Sheet No. 110: Eliminates outdated language in Section J., Non-Standard Service, specifically:

9

or b) the premises become an inactive account for a consecutive period of six (6) months or more. Any premises meeting the conditions of (a), or (b) herein shall be considered to have been constructed after June 1, 1981, for application of 4 CSR 240-20.050 of the Commission's metering requirements and related Sections Rent Inclusion and Resale of Service, which are a part of the Billing Practices Section of Company's General Rules and Regulations.

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– Staff does not oppose;

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4. Sheet No. 115: Correction to Section reference, Overhead Extensions To Residential Subdivisions in Section 1.a. – Staff does not oppose;

21

22

5. Sheet No. 123: Correction to Special Facilities reference in Section 2 – Staff does not oppose;

23

24

6. Sheet No. 134: Updated language to Section 5 prohibiting eligibility for optional rates under 2(M) when a large customer requests a temporary transfer to the 2(M) rate class due to abnormal operations. – Staff does not oppose;

25

26

27

28

7. Sheet No. 137: Correction to Rent Inclusion section number reference – Staff does not oppose;

29

30

8. Sheet No. 138: Correction to Missouri Code of State Regulations reference in Partial Payments Section – Staff does not oppose;

31

1           The tariff sheets appended to Mr. Harding’s testimony (and submitted to initiate this  
2 case) also include Sheet 84.2 Reserve Distribution Capacity Rider which includes a change in  
3 reference to the Distribution System Extension. Staff does not oppose this change. The tariff  
4 sheets appended to Mr. Harding’s testimony (and submitted to initiate this case) also include  
5 Sheet 103 which adds to a provision concerning customer-owned equipment that “following  
6 installation of Company’s metering equipment, not break, remove or tamper with the security  
7 seal or other security device installed on customer-owned equipment by Company.”  
8 This change does not appear to be supported by testimony nor identified in testimony.  
9 Staff reserves recommendation on this change until Ameren Missouri explains the purpose and  
10 intent of the change.

11 **AMEREN MISSOURI’S REQUEST TO COLLECT CURRENT CUSTOMER BILL**  
12 **SAVINGS FROM FUTURE CUSTOMERS**

13           Q.     What specific authority does Ameren Missouri request as a two-way tracker  
14 related to revenue changes that may arise from residential customer rate switching?

15           A.     In Mr. Warren Wood’s testimony at page 6, he states “As witness Wills explains,  
16 Ameren Missouri also requests a two-way tracker related to revenue changes that may arise  
17 from residential customer rate switching.” On page 12, of Mr. Wills testimony, Mr. Wills  
18 states, “TOU rates have an inherent disincentive for the utility to pursue a rapid transition  
19 toward broad adoption. In order to address this issue, I recommend that the Commission  
20 approve a rate switching tracker in this case to address that disincentive.” Mr. Wills testifies  
21 that the tracker balance would be developed by calculating the difference for each customer  
22 between the customer’s bill on the new rate they have chosen compared to what a bill would  
23 have been on the Anytime User rate plan, for the same usage.

1 Q. Does Staff recommend granting the tracking authority requested?

2 A. No. As I will discuss below, Staff recommends that the general request for  
3 “the authority to track revenues lost through this migration,” be denied as unreasonable.  
4 Further, the calculation Mr. Wills describes will calculate a value in excess of the bill savings  
5 experienced by Ameren Missouri customers. Finally, if the requested authority is granted, the  
6 appropriate customer group from which to seek recovery are those customers taking service on  
7 the highly-differentiated Time of Use (“ToU”) rate plans.

8 **The Tracking Authority Requested is Unreasonable**

9 Q. At pages 18 – 19, Mr. Wills quotes a portion of the Commission’s findings of  
10 fact related to Ameren Missouri’s “Charge Ahead” case (File No. ET-2018-0132) including the  
11 statement that “The Commission has often authorized a deferral mechanism when it is  
12 authorizing a new program that is beneficial to customers, but where without the deferral  
13 mechanism in place, it could be financially detrimental to the utility to pursue.” Mr. Wills then  
14 opines that “The last sentence in that section of the order clearly indicates that, where the  
15 Commission sees an opportunity to align the financial incentives of a utility it regulates with an  
16 opportunity for that utility to provide benefits to its customers, a tracker can be good public  
17 policy. The logic that applied to the Charge Ahead tracker applies almost identically with  
18 respect to this rate switching tracker.”

19 What benefit does Mr. Wills assert is made available, and to which customers, to justify  
20 a rate switching tracker under the logic of the language he chose to cite from the Charge Ahead  
21 Report and Order?

22 A. Mr. Wills testifies at page 19 that the TOU rate plans “can provide significant  
23 benefits to those customers in the form of lower bills, achieved in a manner that can also provide



1 system benefits for all customers arising from the shifting of usage away from periods of high  
2 demand, and therefore higher cost, on the system. The Commission has expressed a public  
3 policy interest in advancing TOU rates in recent years in several contexts.” In other words,  
4 Mr. Wills envisions three benefit categories:

- 5 1. Lower bills for opt-in participants;
- 6 2. Potential benefits “arising from the shifting of usage away from periods  
7 of high demand, and therefore higher cost, on the system;”; and
- 8 3. A belief that additional revenue recovery “encourages the Company to  
9 propose more advanced TOU rates and otherwise pursue modernization  
10 of rates in the future as well, and will allow the Company to consider  
11 additional promotional activities around TOU rates if they appear to  
12 provide benefits through the IRP analysis....”

13 Q. Are lower bills for opt-in participants a benefit for all ratepayers which could  
14 reasonably justify a tracker?

15 A. No.

16 Q. Are there real benefits “arising from the shifting of usage away from periods of  
17 high demand, and therefore higher cost, on the system,” due to these rate plans?

18 A. No. In its responses to Staff DR Nos. 0141, 0142, 0143, 0144, and 0145,  
19 attached as Schedule SLKL-r1, Ameren Missouri admitted that it has done no analysis to  
20 quantify any changes in existing residential load that the company projects will be caused by  
21 continued operation of these rate plans. Ameren Missouri stated that it has not performed any  
22 analysis estimating the benefits of these rate plans. Ameren Missouri’s responses indicated that  
23 it is unable to describe the costs or expenses that the Company projects to avoid or reduce due  
24 to what it considers successful implementation of opt-in time-based rate schedules.

1 Specifically, Ameren Missouri not only responded that it had not identified potential early  
2 retirement of distribution and substation infrastructure, transmission and substation  
3 infrastructure, or generation infrastructure due to successful implementation of opt-in time-  
4 based rate schedules occurs, but Ameren Missouri’s responses to each of these questions  
5 included the statement that “*nor is it clear to the Company why implementation of TOU rates*  
6 *would be expected to result in the retirement of infrastructure.*” [Emphasis added.] Finally,  
7 the Ameren Missouri response indicated “*The Company does not currently have forecasts or*  
8 *targets of adoption levels of its optional TOU rates with which to estimate avoided*  
9 *infrastructure costs in the future.*” [Emphasis added.]

10 Ameren Missouri’s responses to Staff DR Nos. 0141, 0142, 0143, 0144, and 0145, make  
11 it unequivocal that benefits “arising from the shifting of usage away from periods of high  
12 demand, and therefore higher cost, on the system” are speculative at best.

13 Ameren Missouri admitted that it has done no analysis to quantify any changes in  
14 existing residential load that the company projects will be caused by continued operation of  
15 these rate plans, Ameren Missouri has not performed any analysis estimating the benefits of  
16 these rate plans, and Ameren Missouri is unable to describe the costs or expenses that the  
17 Company projects to avoid or reduce due to what it considers successful implementation of  
18 opt-in time-based rate schedules.

19 Q. Is the tracker needed to encourage the Company to propose more advanced ToU  
20 rates and otherwise pursue modernization of rates in the future?

21 A. No. The Commission can and should order rate modernization in this and future  
22 rate cases.

1 Q. Even if benefits “aris[e]from the shifting of usage away from periods of high  
2 demand, and therefore higher cost, on the system,” would the tracker described by Mr. Wills  
3 be reasonable?

4 A. No. As I will discuss below, the calculation would remain inappropriate and the  
5 recovery target would require limitation to participants in the high-differential ToU rate plans,  
6 but the tracker would remain unreasonable to recover revenue shortfalls associated with the  
7 high-differential ToU rate plans as currently designed.

8 Q. Why?

9 A. The differentials as currently designed in the Overnight Savers, Smart Savers,  
10 and Ultimate Savers rate plans are not cost-based. Mr. Wills admits the necessity of alignment  
11 of revenue recovery with cost of service as necessary for his requested authority in his testimony  
12 at page 14, stating:

13 First, each of the TOU rates were designed to be revenue neutral to the  
14 legacy rate for the class as a whole – i.e., for the average customer.  
15 However, most customers are not average, and none of them are  
16 precisely average. Every customer could naturally be a "winner" or  
17 "loser" on a new rate before making a single behavior change in response  
18 to the new rate. **This is not a bad thing as long as the rate is aligned**  
19 **well with the cost of serving those customers.** The bill changes that  
20 create the various customer outcomes should generally be moving  
21 customers' bills closer to their true cost of service – this is generally a  
22 good thing to be sure. **[Emphasis added.]**

23 Q. Does Mr. Wills quantify the extent to which these self-selected customers are  
24 “winners,” and “losers,” under his analysis?

25 A. Yes. At page 8 of his Direct Testimony, Mr. Wills testifies that for customers  
26 electing to take service on the Overnight Savers, Smart Savers, and Ultimate Savers rate plans  
27 “around 80% of customer outcomes and individual bills are lower than they would be on the

1 legacy Anytime User rate plan.” However, where rates have been designed to induce changes  
2 in customer load but without any analysis of the load to be changed, the benefits to be added,  
3 or the costs to be mitigated or avoided, there is no grounds for an assumption the resulting bills  
4 are closer to cost of service.

5 Mr. Wills’ analysis establishes that by and large, customers who have opted into these  
6 rate plans contribute less revenue than they would if they had remained on the “Anytime” or  
7 “Evening/Morning Savers” rate plans, but Ameren Missouri has no analysis or grounds to  
8 assume that those customers are any closer to paying their true cost of service than any other  
9 customer. More importantly, there are no grounds to support an assumption that  
10 non-participating customers will be paying closer to their “true cost of service” by  
11 compensating Ameren Missouri’s shareholders for the bill savings realized by participants.

12 Q. Is there any evidence that customers on the opt-in ToU rates are “shifting usage  
13 away from periods of high demand”?

14 A. No.

15 Q. If customers on the opt-in ToU rates are shifting usage away from periods of  
16 high demand, is there any evidence of what costs can be or are being avoided?

17 A. No.

18 Q. To the extent that customers on the opt-in ToU rates are shifting usage away  
19 from periods of high energy prices or to periods of low energy prices, what is the impact of  
20 these shifts on customers and on shareholders?

21 A. Shifting of energy consumption away from periods of high energy prices or  
22 increasing usage in periods of low energy prices will result in a reduction to net fuel costs. By  
23 operation of the Fuel Adjustment Clause (FAC), and without need for a tracker, shareholders

1 will retain 5% of the value of this benefit, and 95% of the value of the benefit will be passed to  
2 all ratepayers on the basis of energy consumption through the FAC.

3 **The Requested Calculation of the Tracker is Unreasonable**

4 Q. At page 17 Mr. Wills states:

5 Impacts would be calculated for each customer that adopts any of the  
6 optional residential TOU rates after the true-up date in this case  
7 (Overnight Savers, Smart Savers, and Ultimate Savers). Their bill on the  
8 new rate they have chosen will be compared to what their bill would have  
9 been on their legacy plan, the Anytime User rate. Any difference will be  
10 accumulated in the tracker for recovery from, or return to, customers in  
11 a future rate review.

12 Is this calculation reasonable?

13 A. No. This approach is unreasonable for at least three reasons.

- 14 1. Increased usage due to effective energy storage
- 15 2. Increased usage due to accretive energy usage
- 16 3. Bill differences encompassed by the FAC

17 Q. What do you mean by effective energy storage?

18 A. One of the behaviors thought to be induced by ToU rates that are designed to  
19 induce behavioral changes is pretreatment of air or thermal masses related to operation of  
20 HVAC equipment and water heating. In practice, this means that customers consume more  
21 energy over all. For example, if someone sets their dryer to run overnight, that person may also  
22 rely on a “fluff” setting to cycle the dryer until the clothing are removed, using more energy  
23 overall than if the clothes had been removed from the dryer sooner.

24 As another example, if I want to minimize my use of my air conditioner between 3 and  
25 7 pm, one way to achieve that is to cool my house down to 62 degrees by 2:59. Then, I may

1 set my thermostat to 82 degrees from 3-7, and lower it back to 72 degrees at 7:01. It is likely  
2 that I will have consumed more energy than if I had kept my thermostat at 72 the entire time.

3 It is not reasonable to view the difference between the rate that would be charged for  
4 energy that would not have been consumed but-for being on the ToU rate plan as an avoided  
5 revenue or bill saving.

6 Q. Has Ameren Missouri asserted that the opt-in ToU rate plans were designed to  
7 induce accretive energy use?

8 A. Yes. Ameren Missouri's position in requesting its electric vehicle charging  
9 subsidy program – "Charge Ahead" was premised on an assumption that customers will use  
10 more energy if they purchase or lease an electric vehicle. Ameren Missouri has asserted that  
11 the "Overnight Saver" program in particular is designed to be attractive to customers who would  
12 like to purchase or lease an EV – increasing their energy consumption - but not otherwise make  
13 behavior changes aligned with ToU rates. It is not reasonable to view the difference between  
14 the rate that would be charged for energy that would not have been consumed but-for being on  
15 the ToU rate plan as an avoided revenue or bill saving.

16 Q. How does the FAC relate to calculation of the difference in what customers  
17 would be charged under different rate plans?

18 A. To the extent that pricing disparities in the opt-in ToU rate plans are intended to  
19 reflect differences in the cost of wholesale energy over various time periods, any savings  
20 actually realized are passed in part to ratepayers and retained in part by shareholders through  
21 the FAC. It would not be appropriate to consider the energy portion of differences between rate  
22 plan charges in calculating an avoided revenue or bill savings.

23 Q. If a tracker is authorized, how should a tracker be calculated?

1           A.     A tracker shouldn't be authorized for the reasons discussed above. Additionally,  
2 the difficulty in accurately calculating a tracker is further reason to not authorize a tracker.  
3 There is not a reasonably accurate method to calculate a tracker as contemplated by Ameren  
4 Missouri in this case.

5           Q.     Mr. Wills testifies at page 18 that "the rate switching tracker is in fact very  
6 analogous to how certain provisions of the MEEIA align utility incentives with helping  
7 customers use energy more efficiently by ensuring utilities are not financially harmed in the  
8 form of lost revenues when taking actions that benefit customers. The legislation that created  
9 MEEIA requires this alignment of incentives for energy efficiency programs. Although such  
10 treatment is not legislatively required in the circumstance of rate design, it is good policy for  
11 the exact same reasons that the legislature saw fit to create such a requirement for energy  
12 efficiency." Does Ameren Missouri's current or any prior MEEIA program require alignment  
13 of incentives in the form of lost revenues?

14          A.     No. If Ameren Missouri's MEEIA program were designed to recover lost  
15 revenues as contemplated in the statute, the situation described by Mr. Wills simply would not  
16 exist. Rather, Ameren Missouri's MEEIA program is designed to recover a "Throughput  
17 Disincentive," which relies on various assumptions to estimate the value of revenues avoided  
18 due to implementation of certain utility-funded measures. Further, Mr. Wills' argument that  
19 the legislature saw fit to authorize a special mechanism and duly enacted a statute to authorize  
20 that mechanism is a poor analogy for arguing that the Commission should authorize a  
21 functionally identical mechanism in this rate case.

1           **If a Tracker is Established, Who Should Pay in Future Rate Cases?**

2           Q.     If the benefit of the opt-in ToU rates is lower bills for participants, is it  
3 reasonable to retrospectively charge all customers to make up for any revenue shortfall caused  
4 by participants?

5           A.     No. The rate plans do not benefit all customers by occasioning a reduction in  
6 utility cost of service outside of the cost of wholesale energy. The changes in cost of service  
7 associated with net wholesale energy purchases are flown through the FAC. The rate plans in  
8 question benefit only those customers participating, and only in the form of reduced revenue  
9 responsibility.

10          Q.     If a tracker is established, and if revenue responsibility for the tracker balance is  
11 extended beyond the participants, how should that revenue responsibility be allocated?

12          A.     Because any energy-cost benefits are passed through the FAC, the costs of the  
13 tracker, if authorized and if not confined to the bills of participants, should be allocated to all  
14 customers in all classes on the basis of loss-adjusted energy sales.

15           **Alternative to Tracker**

16          Q.     The problem underlying the tracker request presented by Mr. Wills is that  
17 customers who have opted into the Overnight Savers, Smart Savers, and Ultimate Savers rate  
18 plans pay less on average per kWh than customers who have not opted-into these rates, while  
19 the cost to serve these customers is essentially the same on a per-kWh basis as customers who  
20 have not opted into these rates. Is there another way to address this problem?

21          A.     Yes. The first way to address this problem would be to redesign these rate plans  
22 so that the differentials in the rate plans correspond to the variations in the cost of providing  
23 service in selected time periods. The second way to address this problem would be to increase



1 the Overnight Savers, Smart Savers, and Ultimate Savers rates so that customers who have  
2 opted into the plans provide the same average revenue per kWh as those who have not opted  
3 into the plans, based on the billing determinants associated with each rate plan.

4 Q. Does anything need to be done in this case to address the problem presented by  
5 Mr. Wills that customers who have opted into the Overnight Savers, Smart Savers, and Ultimate  
6 Savers rate plans pay less on average per kWh than customers who have not opted-into these  
7 rates, while the cost to serve these customers is essentially the same on a per-kWh basis as  
8 customers who have not opted into these rates?

9 A. No. This situation is of Ameren Missouri's own making and is the consequence  
10 of introducing opt-in rate plans that are not cost-based.

11 **UPDATE ON RIDER C ENGINEERING REVIEW**

12 Q. What was Staff's direct- recommended treatment of Rider C adjustments?<sup>1</sup>

13 A. Staff recommends that adjustments offered under Rider C be held constant in  
14 the absence of information to evaluate their reasonableness.

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<sup>1</sup> RIDER C ADJUSTMENTS OF METER READINGS FOR METERING AT A VOLTAGE NOT PROVIDED FOR IN RATE SCHEDULE

Where service is metered at a voltage other than the voltage provided for under the applicable rate schedule, an adjustment in both the kilowatt-hour (kWh) and kilowatt (kW) meter readings for the applicable service will be made as follows:

For customers on rate schedule 2(M) or 3(M) taking delivery at secondary voltage:

1. Metered at Primary Voltage or higher, meter readings (kWh and kW) will be decreased by 0.68%.

For customers on rate schedule 4(M) or 11(M):

2. Metered at 34 kV or higher, meter readings (kWh and kW) will be decreased by 0.68%

3. Metered at Secondary voltage, meter readings (kWh and kW) will be increased by 0.68%

4. Delivered at 34 kV or higher, served through a single transformation to secondary voltage, and metered at secondary voltage, no Rider C adjustment will apply.

\*5. Served at transmission voltage, metered kWh will be increased to account for the energy line losses from the use of a transmission system other than Company's, if any.

Company shall not be required to provide any distribution facilities beyond the metering point except when required for engineering or other valid reasons.

1 Q. In the “Second Unanimous Stipulation and Agreement” filed 12/6/2021, in  
2 ER-2021-0240, Ameren Missouri agreed to “Rider C: The Company will conduct an  
3 engineering review of the Rider C loss rates by December 31, 2022 and will update the Rider C  
4 loss rates in its first electric general rate case filed after December 31, 2022 if the engineering  
5 review indicates an update of those loss rates is needed.” Has Ameren Missouri conducted this  
6 engineering review?

7 A. Staff propounded a Data Request (DR) concerning the specified engineering  
8 review on January 5, 2023. The response to DR No. 0460 was received on January 24, 2023,  
9 attached as Schedule SLKL-r2. This response indicates that the adjustment to the Rider C factor  
10 is warranted. Staff recommends that the Rider C factor be modified from 0.68% to 0.72%,  
11 assuming that there are not transformers on the Ameren Missouri system that are dramatically  
12 oversized, which may warrant creation of adjustment factors particular to the customers served  
13 by such transformers.

14 **“RIDER B STUDY”**

15 Q. What is Rider B?

16 A. Rider B provides:

17 DISCOUNTS APPLICABLE FOR SERVICE TO SUBSTATIONS  
18 OWNED BY CUSTOMER IN LIEU OF COMPANY OWNERSHIP

19 Where a customer served under rate schedules 4(M) or 11 (M) takes  
20 delivery of power and energy at a delivery voltage of 34kV or higher,  
21 Company will allow discounts from its applicable rate schedule as  
22 follows:

23 \*1. A monthly credit of \$1.24/kW of billing demand for customers  
24 taking service at 34.5 or 69kV.

25 \*2. A monthly credit of \$1.47/kW of billing demand for customers  
26 taking service at 115kV or higher.

1 Q. Did the Report and Order in ER-2021-0240 address study of the reasonableness  
2 and design of Rider B credits for customers who are billed at primary rates, but who own their  
3 own substation equipment?

4 A. Yes. In the Report and Order in ER-2021-0240 at pages 31 – 34, the  
5 Commission addressed whether it should require “Performance of a study of the reasonableness  
6 of the calculations and assumptions underlying Rider B to be filed as part of the Company’s  
7 direct filing in its next general rate case?” The decision paragraph at pages 33-34 states:

8 The Commission will not suspend the Rider B credits, but it believes the  
9 question of the proper calculation of those credits should be further  
10 addressed in Ameren Missouri’s next rate case. Therefore, the  
11 Commission will direct Ameren Missouri to study the reasonableness of  
12 the calculations and assumption underlying Rider B and to file the results  
13 of that study as part of its direct filing in its next general rate case.

14 Q. Has Ameren Missouri prepared a study of the reasonableness of the calculations  
15 and assumptions underlying Rider B and filed those results in its direct filing in this rate case?

16 A. No.

17 Q. Please summarize Mr. Hickman’s testimony at 27 – 28.

18 A. Mr. Hickman describes the following calculation:

- 19 1. Mr. Hickman calculated an estimate of the revenue  
20 requirement attributable to distribution substations  
21 (FERC Account 362).
- 22 2. Mr. Hickman multiplied the resulting revenue  
23 requirement amount times the Class NCP Demand at the  
24 High Voltage Level for the SPS and LPS classes,
- 25 3. Mr. Hickman divided the result of Step 2 by the combined  
26 total billing demand of the SPS and LPS classes, yielding  
27 a result of \$1.34 per kW.

28 Mr. Hickman then testifies that “The calculated result from the study should most  
29 closely match the 115 kV and above rate, as those customers do not utilize any substations in

1 the 362 account, whereas customers served at 34.5 or 69 kV would utilize a subset of those  
2 substations but not all of them – and far less than customers served at standard primary or  
3 secondary voltages. Although the calculated discount of \$1.34 per kW is slightly different from  
4 the \$1.47 per kW discount currently being given to those customers, because the Company is  
5 recommending equal percentage increases for all customer classes, the Company recommends  
6 making an equal percentage adjustment to Rider B consistent with all customer classes.”

7 Q. Does Ameren Missouri maintain that this testimony constitutes the ordered  
8 study?

9 A. Yes. Staff DR No. 0461 requested “(1) Please provide the referenced study.  
10 (2) Please identify the date the referenced study was started, and the date it was completed.  
11 (3) If the study is not completed, please provide all information Ameren Missouri would rely  
12 upon in the conduct of the study.” Ameren Missouri responded “1. Please see the direct filing  
13 testimony of Company witness Thomas Hickman and the submitted direct filing workpaper  
14 titled "Rider B Analysis Final". 2. Exact dates during which the study was performed are not  
15 known but the study (including preliminary conversations) was conducted between  
16 approximately April 2022 and July 2022. 3. N/A.”

17 Q. Did Mr. Hickman study the relationship of cost causation and revenue  
18 sufficiency associated with the discounts provided to certain customers under Rider B?

19 A. No.

20 Q. How would such a review be conducted?

21 A. The first step would be to gather factual data concerning the infrastructure and/or  
22 the cost of the infrastructure that operates as customer-specific infrastructure for the relevant

1 customers. Data could be gathered for either all relevant customers or a subset of relevant  
2 customers that constitutes a reasonable sample.

3 Q. How would Ameren Missouri determine which customers are relevant to gather  
4 such data?

5 A. Rider B is available to customers served under rate schedules 4(M) or 11 (M)  
6 who take delivery of power and energy at a delivery voltage of 34kV or higher, specifically  
7 at 34.5kV, 69kV, 115kV, or higher, when those customers own their own customer-specific  
8 infrastructure. So, the relevant customers to study would be those served under rate schedules  
9 4(M) or 11 (M) taking delivery of power and energy at a delivery voltage of 34kV or higher,  
10 specifically at 34.5kV, 69kV, 115kV, or higher, when those customers rely on  
11 customer-specific infrastructure which is included in Ameren Missouri's rate base and  
12 reflected in Ameren Missouri's regulated cost of service. Because Rider B is intended to  
13 provide a credit to customers who do not cause Ameren Missouri to own and operate their  
14 customer-specific infrastructure, it is appropriate to determine the cost of service to own and  
15 operate comparable customer-specific infrastructure.

16 Q. What information would be gathered concerning the customer-specific  
17 infrastructure used to serve these customers?

18 A. The necessary information is a survey of the actual equipment installed in and  
19 on the ground that is included in the Ameren Missouri rate base, and is used to serve these  
20 specific customers but not otherwise interconnected with the Ameren Missouri grid. Obtaining  
21 this information would likely follow one of two paths:

- 22 1. A site visit to facilities associated with these customers,
- 23 2. Identification of the type, size, and quantity of assets located at  
24 representative customer locations that are Ameren Missouri assets,

1           3.     Identification of the accounts to which the assets identified are  
2           booked.

3           The alternative path to obtaining this information is:

- 4           1.     Review of Ameren Missouri records of assets known to be  
5           customer specific, such as substations and lines named for those  
6           customers for which they serve as customer-specific assets.  
7           2.     Identification of the type, size, and quantity of assets.  
8           3.     Identification of the accounts to which the assets identified are  
9           booked.

10          Q.     Would this information have any value outside of the context of the calculation  
11 of Rider B?

12          Q.     Yes. This information is the same information that would ideally inform the  
13 allocation of customer-specific infrastructure in a well-conducted CCoS Study, as discussed  
14 below. Therefore, Staff recommends that the Commission order Ameren Missouri to complete  
15 a study of the cost of customer-specific assets associated with customers taking service at each  
16 major voltage level, including but not limited to: secondary low voltage single phase, secondary  
17 low voltage three phase, secondary high voltage, primary, subtransmission, and transmission.

18          **CCOS STUDY RESULTS AND INTERCLASS REVENUE SHIFTS**

19          Q.     At page 29 Mr. Chriss provides as follows:

20                 My understanding is that Ameren incurs three types of costs to serve  
21                 LGS and SP customers: Customer, Demand, and Energy. Demand costs  
22                 are fixed costs incurred by the Company to size the system such that it  
23                 can meet the peak kW demands imposed by the rate class and do not  
24                 change with changes in how many kWh of energy are consumed by  
25                 customers. Customer costs are also fixed costs, which are incurred based  
26                 on the number of customers served by the Company, and do not vary by  
27                 the size of each customer or how much energy customers consume.  
28                 Given that both the demand and customer costs are fixed, they should  
29                 not be collected through a variable energy charge. In contrast, energy  
30                 costs are variable costs incurred by the Company in relation to the

1 amount of energy consumed by customers. In order to send proper price  
2 signals, energy charges should only be used to collect variable costs such  
3 as operations and maintenance and fuel costs.

4 Could you explain the misconceptions that underlie these discussions?

5 A. Ameren Missouri incurs costs to connect customers to its infrastructure, to  
6 generate energy for sale at wholesale, to purchase energy to serve its customers as needed, to  
7 satisfy various regulatory requirements at state and federal levels, to perform administrative  
8 functions, and to satisfy its shareholders. Each of these costs and expenses can be treated for  
9 class cost of service purposes as related to “Customer, Demand, or Energy,” but in reality a  
10 given expenditure is likely related to all three of these, a combination of two of these, or none  
11 of these.

12 For example, right now Ameren Missouri has a solar Certificate of Convenience and  
13 Necessity (“CCN”) filing to install production capacity to meet “an energy need.” Under  
14 Mr. Chriss’ definition and consistent with the Ameren Missouri CCoS Study on which he relies,  
15 this solar capacity would be considered a demand cost. If Coincident Peak (“CP”) capacity  
16 were truly the only consideration in generation selection with or without market participation,  
17 all capacity needs would be met with a capacitor.<sup>2</sup>

18 Finally, given the integrated market which has been in place for Ameren Missouri at  
19 MISO for approaching its second decade, while fuel costs are variable, they vary with the  
20 demand for energy in a given hour of the regional load, and do not vary with the Ameren  
21 Missouri load. In fact, in hours when Ameren Missouri is generating more energy than its load  
22 requires, these variable costs net to vary inversely with the Ameren Missouri load.

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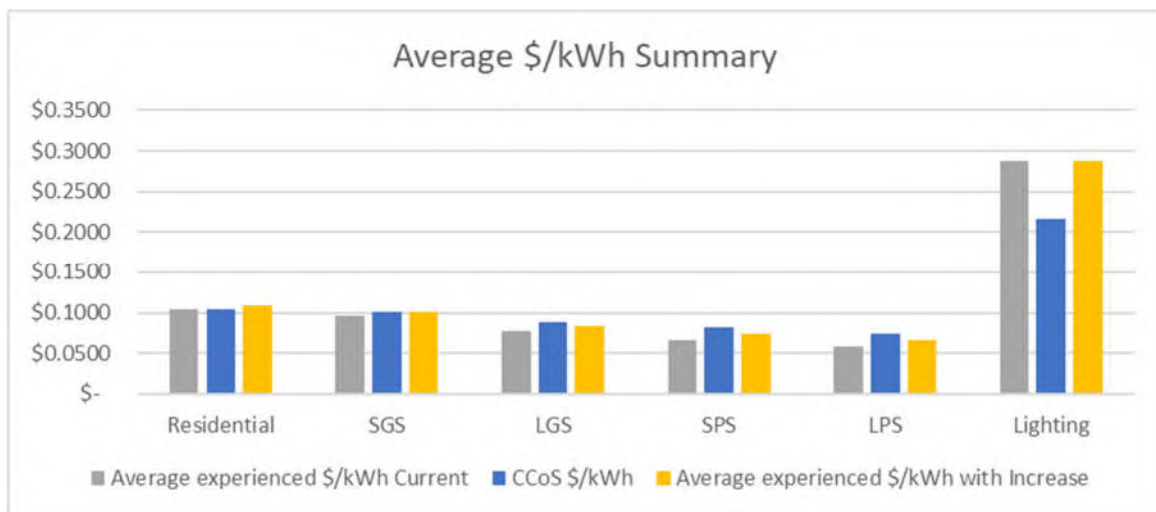
<sup>2</sup> Coincident Peak refers to the highest interval of energy usage across multiple customer groups.

1 Q. Do you recommend reliance on the Ameren Missouri CCoS Study performed by  
2 Mr. Hickman and relied upon by Mr. Harding for purposes of determining class-level revenue  
3 responsibility?

4 A. No. The Ameren Missouri study is wholly unreasonable in the manner in which  
5 distribution costs and expenses are directly allocated, and relies on an approach for allocation  
6 of the production revenue requirement that is inconsistent with Ameren Missouri's participation  
7 in the MISO energy and capacity markets. The unreasonable revenue requirement allocations  
8 resulting from these functions are exacerbated by the indirect allocation of much of the  
9 remaining revenue requirement on the basis of the direct allocations in these functions.

10 Q. Do you agree with the class-level revenue responsibility (interclass revenue  
11 requirement) recommendations of Mr. Chriss or Mr. Brubaker?

12 A. No. These recommendations are based on the unreasonable Ameren Missouri  
13 study, with minor revisions in the case of Mr. Chriss. These recommendations are inconsistent  
14 with my more reasonable study results and my recommended interclass revenue responsibility  
15 recommendations, summarized below:

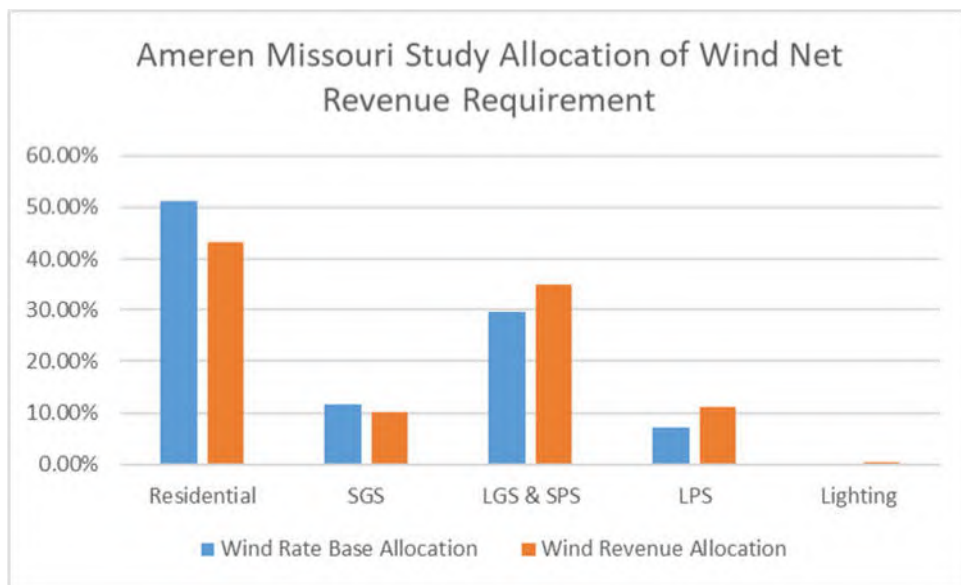




**Production Revenue Requirement**

Q. Is it reasonable to recover the majority of the revenue requirement for wind, solar, and hydro generation from one set of customers and to refund the majority of the revenue from the energy sales of those units to a different set of customers?

A. No. Further, this allocation approach ignores the requirements of the Missouri Renewable Energy Standard, which are based on energy consumption. The inconsistency and fundamental unfairness of the approach underlying the Ameren Missouri study is provided below:



Q. Do Ameren Missouri, MECG, or MIEC acknowledge Ameren Missouri’s explicit testimony that wind generation additions have been done for purposes of compliance with the Missouri Renewable Energy Standard?

A. No. Matt Michels’ testimony in EA-2019-0181 explicitly states that RES compliance drove the “need” for the recent wind farm additions, beginning at page 2:

1 Q. What is the purpose of your direct testimony in this proceeding?

2 A. The purpose of my direct testimony is to support Ameren Missouri's  
3 application for a Certificate of Convenience and Necessity ("CCN") for  
4 the Outlaw Wind Project (the "Project"), which is being built so that  
5 Ameren Missouri can meet its compliance obligations under the  
6 Missouri Renewable Energy Standard ("RES").

7 Q. Please summarize the conclusions of your direct testimony.

8 A. Beginning in 2021, Ameren Missouri must have Renewable Energy  
9 Credits ("RECs") representing at least 15% of its retail sales in order to  
10 satisfy its RES obligations. Missouri wind resources are an attractive  
11 option for meeting this need. The proposed Project represents a  
12 significant portion of the portfolio of resources that are needed to comply  
13 with the RES in a cost-effective manner. For these reasons, the Missouri  
14 Public Service Commission ("Commission") should approve the  
15 Company's application for a CCN for the Project.

## 16 II. THE NEED FOR RENEWABLE RESOURCES

17 Q. Please briefly describe the Missouri RES and its requirements.

18 A. The RES was passed by Missouri voters via a ballot initiative in 2008.  
19 The RES requires that Missouri's investor-owned utilities acquire  
20 renewable resources equal to increasing percentages of their respective  
21 retail sales. As noted, the requirement reaches a minimum of 15% of  
22 retail sales in 2021. The RES includes a 1.25 times multiplier for  
23 renewable energy generated within the state of Missouri to encourage  
24 in-state development of renewable resources so that 1 megawatt ("MW")  
25 of generation in Missouri results in 1.25 RECs for RES compliance  
26 purposes.

27 Q. What is Ameren Missouri's need for renewable resources starting in  
28 2021?

29 A. To meet the 15% RES requirement, Ameren Missouri will need to  
30 retire a minimum of approximately 4.5 million RECs each year.

31 Q. Does Ameren Missouri already have renewable resources that can be  
32 used to meet some or all of this need?

33 A. It has some of the resources it needs. Ameren Missouri owns  
34 renewable resources, including hydroelectric, solar, and landfill gas  
35 resources. Ameren Missouri also has a contract (the term of which ends  
36 in August 2024) for 102 MW of wind energy from Horizon's Pioneer  
37 Prairie wind farm in northern Iowa. Together, these resources currently  
38 generate approximately 1.4 million RECs annually. In addition, the  
39 Company has also entered into agreements to purchase the High Prairie  
40 Wind Project and the Brickyard Hills Wind Project, which together are  
41 expected to generate roughly 2.4 million RECs annually.

1 Q. Is the Average and Excess Allocator reasonable for allocation of the revenue  
2 requirement associated with generation equipment included in the Ameren Missouri rate base?

3 A. No. The reasonableness of this allocator for Ameren Missouri has declined since  
4 at least 2005, when the MISO integrated marketplace was introduced. At this time, with the  
5 adoption of the new Resource Adequacy model, it is fully irrelevant.

6 Q. Does the Ameren Missouri study rely on an Average and Excess method of  
7 production cost allocation?

8 A. Yes. Mr. Hickman uses a 4NCP A&E allocator for all production plant costs  
9 and certain expenses, and the loss-weighted energy allocator for remaining production expenses  
10 and for revenues from energy sales. Mr. Brubaker relies upon this production cost allocation  
11 for his derivative CCoS study, and expands the use of the 4NCP A&E allocator to certain  
12 expense components.<sup>3</sup> Mr. Chriss slightly modifies the 4NCP allocation by selecting slightly  
13 different peaks for some classes, but otherwise relies on the Ameren Missouri allocation.

14 Q. Mr. Chriss includes the following exchange at pages 31-32, could you reconcile  
15 these statements with the derivation of the A&E allocators?

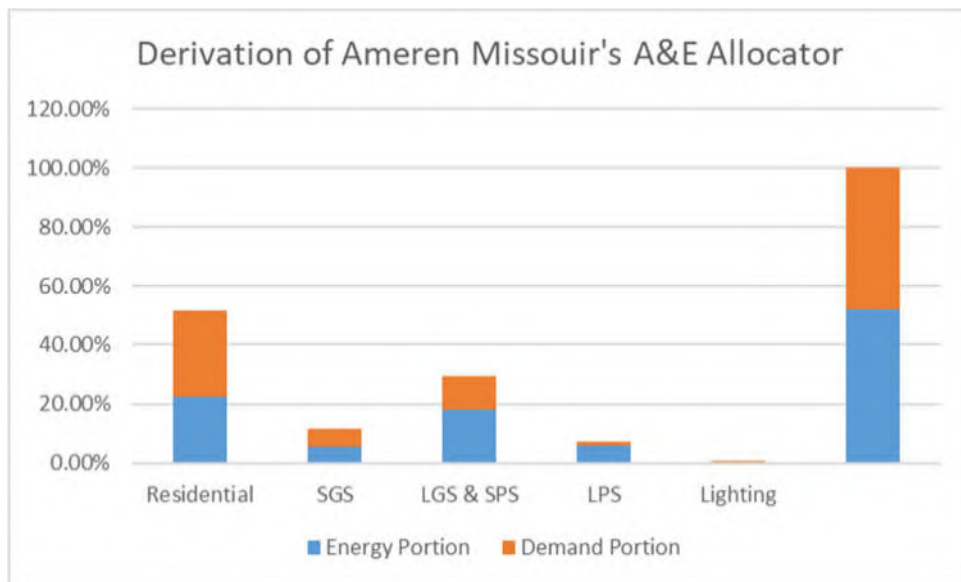
16 Q. IS THE COLLECTION OF DEMAND-RELATED COSTS  
17 THROUGH AN ENERGY CHARGE CONSISTENT WITH THE  
18 COMPANY'S CLASSIFICATION AND ALLOCATION OF  
19 DEMAND-RELATED COSTS?

20 A. No. In its class cost of service study, the Company does not classify  
21 or allocate any of its demand-related costs on an energy basis. Rather,  
22 these costs are incurred, and therefore classified, based on customer  
23 demand or number of customers. Costs should be collected in a manner  
24 which reflects how they are incurred. As such, collecting demand-related  
25 (fixed) costs through an energy (variable) charge violates cost causation  
26 principles.

---

<sup>3</sup> Brubaker direct, page 3.

1           A.       While I do not agree with reliance on the A&E allocator for allocation of Ameren  
2 Missouri’s production costs, Ameren Missouri’s calculation of the A&E allocator allocates  
3 52.054% of production rate base on the basis of class energy requirements, and 47.946% of  
4 production rate base on the basis of demand. Mr. Chriss’s assertion that the company did not  
5 “allocate any of its demand-related costs on an energy basis” is not an accurate characterization  
6 of the A&E method in the context of his assertion that all production plant is demand-related.



9           Recall, due to Ameren Missouri’s participation in the MISO IM, its fuel costs vary with  
10 the demand for energy in a given hour of the regional load, and do not vary with the Ameren  
11 Missouri load. Mr. Chriss (as well as Mr. Brubaker and Mr. Hickman) fail to recognize this  
12 relationship, and their studies do not reflect MISO load. While the Staff study relies on hourly  
13 class loads and MISO DA LMPs to find the variable cost of energy for each class, the Ameren  
14 Missouri and derivative studies assume every kWh of energy consumed has the same cost. This  
15 anachronism further undermines the usefulness of the A&E-based study results.

1 Q. At pages 4-7 of his direct testimony, Mr. Brubaker presents his familiar tomato  
2 discussion. What is the relevance of this discussion to the A&E allocation method?

3 A. Through its reliance on load factor as a surrogate for hourly load data, the A&E  
4 approach essentially assumes that all classes follow the same pattern of energy consumption.  
5 In other words, the A&E method allocates the cost for tomatoes on the assumption that all  
6 customers want tomatoes more or less at the same time, but some customers want a lot more  
7 tomatoes than usual at times when other customers just want a few more tomatoes than usual,  
8 and that the customers who only want a few more tomatoes than usual will want a few less  
9 tomatoes than usual at the same time that the other customers want a lot less tomatoes than  
10 usual. The A&E method ignores the reality that some customers want a lot of tomatoes to make  
11 gazpacho in August when the supply of tomatoes is abundant and they are less expensive to  
12 grow, while some customers want a lot of tomatoes to make soup in January, when tomatoes  
13 are much more expensive to produce and the supply is more constrained.

14 Q. In this case, did either Mr. Hickman, Mr. Wills, Mr. Harding, Mr. Brubaker, or  
15 Mr. Chriss do an analysis of the relationship of Ameren Missouri's hourly loads to determine  
16 whether all classes followed the same relative consumption pattern?

17 A. There has been nothing filed to suggest that any of these gentlemen undertook  
18 such an analysis to determine whether the A&E represents a reasonable surrogate for reliance  
19 on hourly load data for production revenue requirement allocation.

20 Q. In this case, does the relationship of class level hourly loads establish that all  
21 classes followed the same relative consumption patterns? If so, is the relationship consistent  
22 enough that the A&E allocation method could be a reasonable surrogate for reliance on hourly  
23 load data for production revenue requirement allocation if it were otherwise appropriate?

1           A.     I don't know. Rather than undertake such an analysis to determine the  
2 reasonableness of a surrogate for hourly load data, I simply relied on the hourly load data of  
3 Ameren Missouri's customer classes. The A&E method is an artifact from a time when accurate  
4 hourly loads at a class level were virtually unknowable, and the time required for an analyst to  
5 do 8,760 calculations for each rate class on a 10-key calculator would have been a rarity. Today,  
6 a simple excel spreadsheet can be used to determine the exact cost of day-ahead energy for each  
7 class in each hour in minutes.

8           Whatever relevance the A&E production allocation method had before participation in  
9 integrated energy markets, or for utilities that do not participate in capacity markets, the A&E  
10 production method is fully irrelevant to Ameren Missouri due to the seasonal resource adequacy  
11 construct now adopted by MISO and discussed at length in my direct testimony. Mr. Hickman,  
12 Mr. Brubaker, and Mr. Chriss do not acknowledge this fundamental shift in utility capacity  
13 requirements nor attempt to reconcile the selection of the A&E allocator with this requirement.

14           Q.     Under a Non-Coincident Peak (NCP) A&E method, does combining the LGS  
15 and SPS classes for study purposes change the overall allocation percentages for all customer  
16 classes?

17           A.     Yes. A class's NCP means the highest usage exhibited by a class in a given time  
18 period (month/year, etc.). Even if the hour of peak for each class varied by as little as an hour,  
19 the collective LGS/SPS NCP would be lower than the NCP of each class on its own, added  
20 together. A simple example is illustrated below:

1

	<b>2:00</b>	<b>3:00</b>	<b>4:00</b>	<b>5:00</b>	<b>6:00</b>	<b>Max</b>
Residential	1,000	1,100	1,200	1,100	1,000	1,200
SGS	500	550	540	520	500	550
LGS	300	310	325	330	340	340
SPS	340	330	325	310	300	340
LPS	400	405	410	405	400	410
<b>LGS &amp; SPS</b>	<b>640</b>	<b>640</b>	<b>650</b>	<b>640</b>	<b>640</b>	650

2

3

4

5

6

In this example the LGS NCP occurs at 6:00, and is 340, and the SPS NCP occurs at 2:00, and is 340. However, the combined LGS and SPS NCP occurs at 4:00 and is 650, consisting of class demands of 325 for each constituent class. The difference in the allocator created by this example is demonstrated below:

7

	<b>True NCP</b>	<b>True NCP with Classes Summed</b>	<b>Combined NCP</b>	<b>Difference</b>
Residential	42.25%	42.25%	42.70%	-0.5%
SGS	19.37%	19.37%	19.57%	-0.2%
LGS	11.97%	23.94%	23.13%	0.81%
SPS	11.97%			
LPS	14.44%	14.44%	14.59%	-0.2%

8

9

Q. Have you analyzed Mr. Hickman's workpaper concerning the actual value of this issue in his calculation of a production allocator?

10

11

A. Yes. First, I found the sum of the LGS and SPS classes' NCPs for each month, and compared them to the NCPs for each month Ameren Missouri relied upon for the total class:

12

13

1

	Hickman NCP	Summed NCP	Difference
<i>Apr-21</i>	1,591,354	1,591,354	0
<i>May-21</i>	1,791,318	1,794,794	3,476
<i>Jun-21</i>	1,976,649	1,976,649	0
<i>Jul-21</i>	2,235,599	2,238,507	2,908
<i>Aug-21</i>	2,187,544	2,201,303	13,759
<i>Sep-21</i>	2,066,732	2,066,732	0
<i>Oct-21</i>	1,672,851	1,672,851	0
<i>Nov-21</i>	1,623,509	1,654,552	31,043
<i>Dec-21</i>	1,821,417	1,824,887	3,470
<i>Jan-22</i>	1,897,520	1,897,520	0
<i>Feb-22</i>	1,710,010	1,723,867	13,857
<i>Mar-22</i>	1,676,165	1,688,738	12,573

2

3

Then, I inserted this calculation into Mr. Hickman's production allocator worksheet,

4

resulting in the differences in allocation reflected below:

5

	Residential	SGS	LGS & SPS	LPS	Lighting
<b>Ameren Missouri Direct</b>	0.513025	0.116344	0.295210	0.072425	0.002996
<b>Corrected</b>	0.512667	0.116266	0.295665	0.072407	0.002996
<b>Difference</b>	-0.000357	-0.000078	0.000455	-0.000018	-0.000001

6

7

Q. These differences seem very small, can they make a noticeable difference in the

8

results of a CCoS?

9

A. Yes, definitely. Ameren Missouri directly allocated \$6.4 billion of net rate base

10

with this allocator, as well as \$701 million in direct expense allocation. The direct allocated

11

revenue requirement is \$1,161,637,094, with significant indirect allocation following this

12

allocation, including pension and labor expense, property taxes, and PISA allocations.

13

The changes in class revenue requirement associated with only this direct allocation is

14

provided below:



1

	Residential	SGS	LGS & SPS	LPS	Lighting
<b>Corrected Allocator</b>	51.2667%	11.6266%	29.5665%	7.2407%	0.2996%
<b>Difference in Allocator</b>	-0.0357%	-0.0078%	0.0455%	-0.0018%	-0.0001%
<b>Corrected Allocation</b>	\$ 595,533,087	\$ 135,058,806	\$ 343,454,927	\$ 84,110,478	\$ 3,479,796
<b>Difference in Allocation</b>	<b>\$ (415,210)</b>	<b>\$ (91,149)</b>	<b>\$ 528,467</b>	<b>\$ (21,122)</b>	<b>\$ (986)</b>
<b>Ameren's Study Net Income:</b>	\$ 244,140,460	\$ 66,636,321	\$ 214,373,829	\$ 60,422,552	\$ 12,067,038
<b>Adjusted operating Income:</b>	\$ 244,390,979	\$ 66,691,316	\$ 214,054,976	\$ 60,435,296	\$ 12,067,633
<b>Adjusted Rate Base:</b>	\$ 6,346,981,647	\$ 1,364,897,327	\$ 3,022,654,857	\$ 668,438,015	\$ 202,807,279
<b>Ameren Study RoR:</b>	3.8463%	4.8818%	7.0935%	9.0391%	5.9500%
<b>Adjusted RoR:</b>	3.8505%	4.8862%	7.0817%	9.0413%	5.9503%

2

3

Q. Have you made a comparable estimate of the change in direct allocated plant only that result from modifying the A&E allocator to allocate the rate base of Pioneer Prairie and the Atchison wind farm on the basis of loss-adjusted energy?

4

5

6

A. Yes. The changes in class revenue requirement associated with only this direct allocation is provided below:

7

8

	Residential	SGS	LGS & SPS	LPS	Lighting
<b>Corrected Allocator</b>	49.8689%	11.3790%	30.5199%	0.0000%	7.9076%
<b>Difference in Allocator</b>	-1.4335%	-0.2554%	0.9989%	0.0000%	0.6651%
<b>Corrected Allocation</b>	\$ 579,296,079	\$ 132,183,224	\$ 354,530,279	\$ -	\$ 91,857,273
<b>Difference in Allocation</b>	<b>\$ (16,652,218)</b>	<b>\$ (2,966,731)</b>	<b>\$ 11,603,818</b>	<b>\$ -</b>	<b>\$ 7,725,673</b>
<b>Ameren's Study Net Income:</b>	\$ 244,140,460	\$ 66,636,321	\$ 214,373,829	\$ 60,422,552	\$ 12,067,038
<b>Adjusted operating Income:</b>	\$ 254,187,673	\$ 68,426,315	\$ 207,372,598	\$ 60,422,552	\$ 7,405,708
<b>Adjusted Rate Base:</b>	\$ 6,330,744,639	\$ 1,362,021,745	\$ 3,033,730,208	\$ 668,459,138	\$ 210,533,938
<b>Ameren Study RoR:</b>	3.8463%	4.8818%	7.0935%	9.0391%	5.9500%
<b>Adjusted RoR:</b>	4.0151%	5.0239%	6.8356%	9.0391%	3.5176%

9

10

### Transmission Revenue Requirement and Rate Base

11

Q. Which rate schedules currently include reactive demand charge elements?

12

A. The LPS and SPS rate schedules include reactive demand charges, as well as the Large Transmission Service schedule.

14

Q. Which classes of customers currently drive reactive demand requirements?

15

A. This information is not currently considered in Ameren Missouri's CCoS Study. Staff is unaware of data currently maintained by Ameren Missouri that would inform allocation of costs related to voltage support necessitated by disproportionate draw of reactive demand.

17

1 Q. In general, how are reactive demand requirements currently met?

2 A. In general, large synchronous generators balance grid voltages. In June, Ameren  
3 Missouri added a Static Compensator (StatCom) related to the retirement of Meramac. Ameren  
4 has indicated plans to install four additional StatComs at four separate transmission substations,  
5 as well as plans to install additional transmission infrastructure related to the retirement of the  
6 Sioux generating station.

7 Q. What does a StatCom do?

8 A. StatComs are devices that can regulate voltage when the demand for reactive  
9 power exceeds that available on the grid. As rotating mass generation – especially rotating  
10 mass generation located in close proximity to load – is retired, voltage collapse can result from  
11 reactive demand imbalances, which can cause blackouts. Given the prevalence of rotating mass  
12 generation – especially rotating mass generation located in close proximity to load – in the past  
13 generation fleet composition, this issue was relatively minor. At the historic levels of rotational  
14 mass generation, reactive power issues tended to be hyper-local and related to large industrial  
15 loads, which could be addressed with deployment of capacitor banks or related devices. With  
16 the shrinking share of rotational mass generation in the Midwest, it is likely that a prudent  
17 energy company would be collecting and retaining data concerning the reactive demand  
18 position of various portions of its distribution system. Issues that arise due to reactive demand  
19 imbalances are likely to emerge on a local level, so to the extent that infrastructure or other  
20 increases to revenue requirement are necessary to address a reactive demand issue, system-wide  
21 reactive demand determinant charges for those classes which currently have reactive demand  
22 charges will not be useful to either allocate the increased revenue requirement among classes,  
23 or to bill customers within classes.

1 Q. To clarify, is Staff suggesting that it may be necessary in the near term future to  
2 allocate revenue requirement to all classes on the basis of reactive demand?

3 A. Yes. To the extent that installation of StatComs or other infrastructure is  
4 necessary to provide voltage support in the absence of centrally-located rotating mass  
5 generation, reactive demand on the class level would be the obvious allocator to use in a  
6 future CCoS.

7 Q. To further clarify, is Staff suggesting that it may be appropriate in the near future  
8 to incorporate a discrete reactive demand charge to residential and SGS customer bills?

9 A. Yes, it is a possibility. Factors to consider will be the level of revenue  
10 requirement allocated to those classes on the basis of reactive power requirements and the  
11 uniformity (or lack thereof) of reactive power requirements within those classes. If the revenue  
12 requirement is low, and the intraclass-uniformity is high, a discrete charge would not be  
13 necessary. If the revenue requirement is high and the intraclass-uniformity is low, a discrete  
14 charge may be reasonable. The Staff recommended data retention measures stated below would  
15 make such future determinations possible.

16 Q. What types of end-uses disproportionately require reactive power?

17 A. Reactive power is required in excess of apparent power in devices that induce  
18 magnetic fields, such as pumps and motors. Common appliances that require disproportionate  
19 reactive power include heat pumps, refrigeration equipment, and motors (including fans).  
20 Examples of end uses that typically do not draw disproportionate reactive power include heating  
21 elements such as those found in dryers or electric ranges, and electronics (excluding cooling  
22 components). Note, the transmission and distribution systems themselves operate in a manner

1 that requires or provides reactive power, particularly in operation of transformers, and in the  
2 performance of the system in very high and very low loading positions.

3 Q. How should transmission plant additions related to voltage support be recorded?

4 A. To maintain future allocation options, Staff recommends transmission assets  
5 related to maintenance of voltage support due to the retirement of large synchronous generators  
6 be recorded to new subaccounts. Staff further recommends that customer and rate schedule  
7 characteristics related to draws of reactive demand be recorded for study for potential use in  
8 allocators, and for potential creation of determinants for customer billing.

### 9 **Distribution Revenue Requirement**

10 Q. Is the Ameren Missouri distribution allocation reasonably performed and  
11 consistent with the National Association of Regulated Utility Commission (NARUC)?

12 A. No. Ameren Missouri chose to perform what it describes as a minimum  
13 distribution system study. However, the approach Ameren Missouri has taken is not consistent  
14 with the rationale underpinning a minimum distribution system study.

15 Q. What is the rationale underpinning a minimum distribution system study?

16 A. At pages 90-91, regarding embedded cost of service studies, the NARUC  
17 manual states:

18 Classifying distribution plant with the minimum-size method **assumes**  
19 **that a minimum size distribution can be *built to serve the minimum***  
20 ***loading requirements of the customer.*** The minimum-size method  
21 involves determining the minimum size pole, conductor, cable,  
22 transformer, and service that is currently installed by the utility.  
23 Normally, the average book cost for each piece of equipment determines  
24 the price of all installed units. Once determined for each primary plant  
25 account, the minimum size distribution system is classified as customer-  
26 related costs. The demand-related costs for each account are the  
27 difference between the total investment in the account and customer-  
28 related costs. Comparative studies between the minimum-size and other

1 methods show that it generally produces a larger customer component  
2 than the zero-intercept method (to be discussed). **[Emphasis added.]**

3 Q. In what ways was Ameren Missouri's distribution classification and allocations  
4 inconsistent with the NARUC Manual or otherwise unreasonable?<sup>4</sup>

- 5 1. Ameren Missouri chose to rely on a classification method that is inherently  
6 inconsistent with its current design and booking of its distribution system.
- 7 2. Ameren Missouri relies on antiquated or non-existent analysis to support its  
8 classification by voltage.
- 9 3. Ameren Missouri did not perform its minimum distribution system study  
10 consistent with NARUC's guidance.
  - 11 a. Ameren Missouri classifies devices as customer-related.
  - 12 b. Ameren Missouri failed to account for the demand-serving capability of  
13 the selected "minimum"-size infrastructure.
  - 14 c. Ameren Missouri failed to identify or allocate customer-specific  
15 substations and other infrastructure.
- 16 4. Ameren Missouri failed to subfunctionalize for the presence of generation-  
17 related infrastructure.
- 18 5. Ameren Missouri did not adjust its approach to account for these shortcomings,  
19 such as by netting customer-allocated values from its voltage-classified  
20 amounts, or weighting customer counts by demand or by limiting customer  
21 counts to network endpoints.

22 Q. How is the minimum-size classification method inherently inconsistent with the  
23 current design and booking of Ameren Missouri's distribution system?

24 A. The minimum-size classification method inherently assumes that each account  
25 contains infrastructure that is sized to serve the smallest customers at the lowest loads possible.

---

<sup>4</sup> There may be reasonable deviation from the NARUC Manual, particularly in areas where there have been changes in cost causation or regulatory framework over the last 30 years.

1 Most Ameren Missouri customers take service at secondary voltage, at 120 or 240 volts, with  
2 a demand of 20 kW or less.

3 At page 95 of the NARUC Manual:

4 Cost analysts disagree on how much of the demand costs should be  
5 allocated to customers when the minimum-size distribution method is  
6 used to classify distribution plant. When using this distribution method,  
7 the analyst must be aware that the minimum-size distribution equipment  
8 has a certain load-carrying capability, which can be viewed as a demand-  
9 related cost.

10 When allocating distribution costs determined by the minimum-size  
11 method, some cost analysts will argue that some customer classes can  
12 receive a disproportionate share of demand costs. Their rationale is that  
13 customers are allocated a share of distribution costs classified as  
14 demand-related. Then those customers receive a second layer of demand  
15 costs that have been mislabeled customer costs because the minimum-  
16 size method was used to classify those costs.

17 Discussion of a marginal cost study at page 138 of the NARUC Manual provides further  
18 context for these issues:

19 The minimum grid approach re-designs the distribution system to  
20 determine the cost in current year dollars of a **hypothetical system that**  
21 **would serve all customers with voltage but not power (or with**  
22 **minimum demand of 0.5 KW)**, yet still satisfy the minimum standards  
23 for pole height and efficient conductor and transformer size. The  
24 calculations can be based either on the system as a whole or on a sample  
25 of areas reflecting different geographical, service and customer density  
26 characteristics.

27 When applying this approach, it is necessary to **take care that the**  
28 **minimum size equipment being analyzed is, in fact, the minimum-**  
29 **sized equipment available, and not merely the minimum the**  
30 **minimum size stocked by the company or usually installed by the**  
31 **company. To the degree that the equipment being costed is larger**  
32 **than a true minimum, the minimum grid calculation will include**  
33 **costs more properly allocated to demand. [Emphasis added.]**

34 Q. Does Ameren Missouri currently own or operate a networked overhead  
35 secondary distribution system?

1           A.       Essentially, no. By Ameren Missouri’s own admission less than 2% of the assets  
2 recorded to the overhead conductors and device Account 365 do not operate at secondary  
3 voltage.<sup>5</sup> In other data sources provided by Ameren Missouri, the level of secondary voltage  
4 infrastructure recorded to Account 365 is 0%.<sup>6</sup> Secondary voltage components are largely  
5 recorded in the services accounts.

6           Q.       Please described Ameren Missouri’s “minimum” distribution system, as studied  
7 by Mr. Hickman.

8           A.       Ameren Missouri’s minimum distribution system relied upon by Mr. Hickman  
9 for classification of Accounts 364-368 operates at primary voltage.

10          Q.       Is there competent evidence in this case supporting Ameren Missouri’s  
11 classification of its distribution system by voltage?

12          A.       No. While there is little to no testimony on the issue, it appears that the voltage  
13 classification relied upon by Mr. Hickman is the workproduct of “Vandas” from 2009, prior to  
14 Ameren Missouri’s multi-billion dollar distribution system expansion campaign.

15          Q.       What guidance is included in NARUC for classifying devices recorded in  
16 Accounts 365 and 367 as customer related under a minimum-size study?

17          A.       At page 91 the NARUC Manual provides the methodologies for determining the  
18 minimum size of distribution plant for use in calculating the customer-classified portion of the  
19 minimum-size method. The entirety of the entries for Accounts 365 and 367 are set out below:

- 20                   2.       Account 365 – Overhead Conductors and Devices  
21                   - Determine minimum size conductor currently being installed.

---

<sup>5</sup> “A.F. Vandas” tab of Hickman CCoS Study workpaper.

<sup>6</sup> Workpaper “MPSC 0635 – 2009 Study COSS Distribution Accounts.xls,” and “Summary” tab of “2022 Minimum Size Study Final” workpaper.

1 - Multiply average installed book cost per mile of minimum size  
2 conductor by the number of circuit miles to determine the customer  
3 component. **Balance of plant account is demand component.** (Note:  
4 two conductors in minimum system.)

5 3. Accounts 366 and 367 – Underground Conduits, Conductors, and  
6 Devices

7 - Determine minimum size cable currently being installed.

8 - Multiply average installed book cost per mile of minimum size cable  
9 by the circuit miles to determine the customer component. Note: one  
10 cable with ground sheath is minimum system.) Account 366 conduit is  
11 assigned, based on ratio of cable account.

12 - Multiply average installed book cost of minimum size transformer by  
13 number of transformers in plant account to determine the customer  
14 component. **Balance of plant account is demand component.**  
15 **[Emphasis added.]**

16 Significant context can be established from the discussion of applications of the  
17 minimum-intercept method, using the text quoted below from pages 93-94:

18 2. Account 365 – Overhead Conductors and Devices

19 - **If accounts are divided between primary and secondary voltages,**  
20 **develop a customer component separately for each. The total investment**  
21 **assigned to primary and secondary; then the customer component is**  
22 **developed for each. Since conductors generally are of many types and**  
23 **sizes, select those sizes and types which represent the bulk of the**  
24 **investment in this account, if appropriate.**

25 - **When developing the customer component, consider only the**  
26 **investment in conductors, and not in devices such as circuit**  
27 **breakers, insulators, switches, etc. The investment in these devices**  
28 **will be assigned later between the customer and demand component,**  
29 **based on the conductor assignment.**

30 - Determine the feet, investment and average installed book cost per  
31 foot for distribution conductors by size and type.

32 - Determine minimum intercept of conductor cost per foot using cost  
33 per foot by size and type of conductor weighted by feet or investment  
34 in each category, and developing a cost for the utility's minimum size  
35 conductor.

36 - Multiply minimum intercept cost by the total number of circuit feet  
37 times 2. (Note that circuit feet, not conductor feet, are used to get  
38 customer component.)



1 - Balance of conductor investment is assigned to demand.

2 - **Total primary or secondary dollars in the account, including**  
3 **devices, are assigned to customer and demand components based**  
4 **on conductor ratio.**

5 3. Accounts 366 and 367 – Underground Conduits, Conductors, and  
6 Devices

7 - The customer demand component ratio is developed for conductors  
8 and applied to conduits. Underground conductors are generally  
9 booked by type and size of conductor for both one conductor (I/c)  
10 cable and three-conductor (3/c) cables. If conductors are booked by  
11 voltage, as between primary and secondary, a customer component is  
12 developed for each. If network and URD investments are segregated,  
13 a customer component must be developed for each.

14 - The conductor sizes and types for the customer component  
15 derivation are restricted to I/c cable. Since there are generally many  
16 types and sizes of I/c cable, select those sizes and types which  
17 represent the bulk of the investment, when appropriate.

18 - Determine the feet, investment and average installed book cost  
19 per foot for I/c cables by size and type of cable.

20 - Determine minimum intercept of cable cost per foot using cost  
21 per foot by size and type of cable weighted by feet of investment  
22 in each category.

23 - Multiply minimum intercept cost by the total number of circuit  
24 feet (I/c cable with sheath is considered a circuit) to get customer  
25 component.

26 - Balance of cable investment is assigned to demand.

27 - Total dollars in Account 366 and 367 are assigned to customer  
28 and demand components based on conductor investment ratio.  
29 **[Emphasis added.]**

30 While there is discussion of the classification of devices in Account 365 pursuant to the  
31 minimum intercept method, under the discussion of Account 365 classification using the  
32 minimum size method, there is the simple and clear statement that “Balance of plant account is  
33 demand component,” unequivocally stating that all devices in Account 365 are classified as

1 demand-related. This is in contrast to the decision of Ameren Missouri to classify \$594,445,713  
2 of plant related to lightening arrestors, switches, and reclosers, as “customer-related”.<sup>7</sup>

3 For the underground accounts under the minimum intercept method, not all devices are  
4 classified as demand-related, however they are neither classified as customer-related, rather,  
5 they are reflected on the ratio of minimum-intercept dollars associated with cables to total cable  
6 dollars in Account 366. Again, in contrast in the description of the minimum size method, there  
7 is the simple and clear statement that “Balance of plant account is demand component,”  
8 unequivocally stating that all devices in Account 366 are classified as demand-related. For the  
9 minimum size method, the ratio of minimum-size cable dollars in Account 366 to total dollars  
10 in Account 366 that is the basis for the classification of Account 367 dollars.

11 Q. How did Ameren Missouri fail to account for the demand-serving capability of  
12 the selected “minimum”-size infrastructure?

13 A. Not only did Ameren Missouri improperly scale its voltage classification when  
14 classifying customer costs (discussed and addressed below), but Ameren Missouri also failed  
15 to follow the guidance provided at page 95 of the NARUC Manual:

16 Cost analysts disagree on how much of the demand costs should be  
17 allocated to customers when the minimum-size distribution method is  
18 used to classify distribution plant. **When using this distribution**  
19 **method, the analyst must be aware that the minimum size**  
20 **distribution equipment has a certain load-carrying capability, which**  
21 **can be viewed as a demand-related cost.**

22 When allocating distribution costs determined by the minimum-size  
23 method, some cost analysis will argue that some customer classes can  
24 receive a disproportionate share of demand costs. Their rationale is that  
25 customers are allocated a share of distribution costs classified as

---

<sup>7</sup> This language also clarifies that Account 365 (Overhead Conductors and Devices) is assumed to include both primary and secondary voltage infrastructure. Concerning the underground accounts, there is again clarity that the accounts are assumed to include both primary and secondary conductors, although the Ameren Missouri selected “minimum” conductor for each is a primary voltage conductor which is oversized for secondary purposes.

1 demand-related. Then those **customers receive a second layer of**  
2 **demand costs that have been mislabeled customer costs because the**  
3 **minimum-size method was used to classify those costs.**

4 Advocates of the minimum-intercept method contend that this problem  
5 does not exist when using their method. The reason is that the customer  
6 cost derived from the minimum-intercept method is based upon the  
7 zero-load intercept of the cost curve. Thus the customer cost of a  
8 particular piece of equipment has no demand cost in it whatsoever.  
9 **[Emphasis added.]**

10 Q. Below, you address and correct Ameren Missouri's improper scaling of its  
11 voltage classification when classifying customer costs. Did you also address the issue discussed  
12 by NARUC at page 95?

13 A. No. Because the minimum-size approach is simply inappropriate for allocating  
14 customer costs where the minimum-size infrastructure is primary voltage, netting the customer  
15 component demand from class-level demand would have resulted in negative allocations to the  
16 Residential, SGS, LGS, and Lighting classes.

17 Q. Did Ameren Missouri identify or allocate customer-specific substations and  
18 other infrastructure consistent with NARUC guidance?

19 A. No. At pages 90-91, regarding embedded cost of service studies, the NARUC  
20 manual states:

21 Classifying distribution plant with the minimum-size method **assumes**  
22 **that a minimum size distribution can be built to serve the minimum**  
23 **loading requirements of the customer.** The minimum-size method  
24 involves determining the minimum size pole, conductor, cable,  
25 transformer, and service that is currently installed by the utility.  
26 Normally, the average book cost for each piece of equipment determines  
27 the price of all installed units. Once determined for each primary plant  
28 account, the minimum size distribution system is classified as customer-  
29 related costs. The demand-related costs for each account are the  
30 difference between the total investment in the account and customer-  
31 related costs. Comparative studies between the minimum-size and other

1 methods show that it generally produces a larger customer component  
2 than the zero-intercept method (to be discussed). **[Emphasis added.]**

3 Discussing marginal costs studies, the minimum-size method, at page 136 the NARUC  
4 manual states:

5 Most analysts agree that distribution equipment that is uniquely  
6 dedicated to individual customers or specific customer classes can be  
7 classified as customer rather than demand related. Customer premises  
8 equipment (meters and service drops) are generally functionalized as  
9 customer rather than distribution costs and, in reality, this is the only  
10 equipment that is directly assignable for all customers, even the smallest  
11 ones. Beyond the customers' premises, however, there are distribution  
12 costs that may be classified as customer related. For example, some  
13 jurisdictions classify line transformers as customer-related often using a  
14 proxy based on average load as the allocation factor when this equipment  
15 is not uniquely dedicated to individual customers. In addition, **for very  
16 large customers, more than merely meters, services, and  
17 transformers are directly assignable. Some have entire substations  
18 dedicated to them. As noted above in "Transmission," distribution  
19 costs of equipment dedicated to individual customers can be directly  
20 assigned to them, thus reducing the common distribution costs  
21 assignable to the remainder of the class. [Emphasis added.]**

22 The portion of the discussion quoted above informs this language, found at page 87 of  
23 the NARUC Manual:

24 Assignment or "exclusive use" costs are assigned directly to the  
25 customer class or group which exclusively uses such facilities. The  
26 remaining costs are then classified to the respective cost components.

27 Q. Did Ameren Missouri make any attempt to identify or allocate customer-specific  
28 substations and other infrastructure?

29 A. No.

30 Q. Does this deviation from reasonable classification of the distribution system  
31 impact only CCoS?

1           A.     No. Due to this critical failure, the Ameren Missouri study is not reliable for  
2 valuing reasonable credits under Rider B, nor for reliance on estimating the revenue to be  
3 reasonably collected from various elements of classes' rate structures.

4           Q.     Did Ameren Missouri address the presence of generation-related infrastructure  
5 in its distribution accounts?

6           A.     No. Ameren Missouri classified and allocated this infrastructure as  
7 distribution-related.

8                           **Adjustments to Ameren Missouri Customer Classification**

9           Q.     Did you perform adjustments to the Ameren Missouri study to review the degree  
10 of overallocation to high customer count classes and under allocation to low customer count  
11 classes due to the deficiencies in the Ameren Missouri study?

12          A.     In part. I present the results of these adjustments at the conclusion of this  
13 section. The necessary revisions to the Ameren Missouri study to render its allocation of  
14 distribution system revenue requirement are extensive.

15          Q.     Did Ameren Missouri take steps to address these shortcomings, such as by  
16 netting customer-allocated values from its voltage-classified amounts, or weighting customer  
17 counts by demand or by limiting customer counts to network endpoints?

18          A.     No.

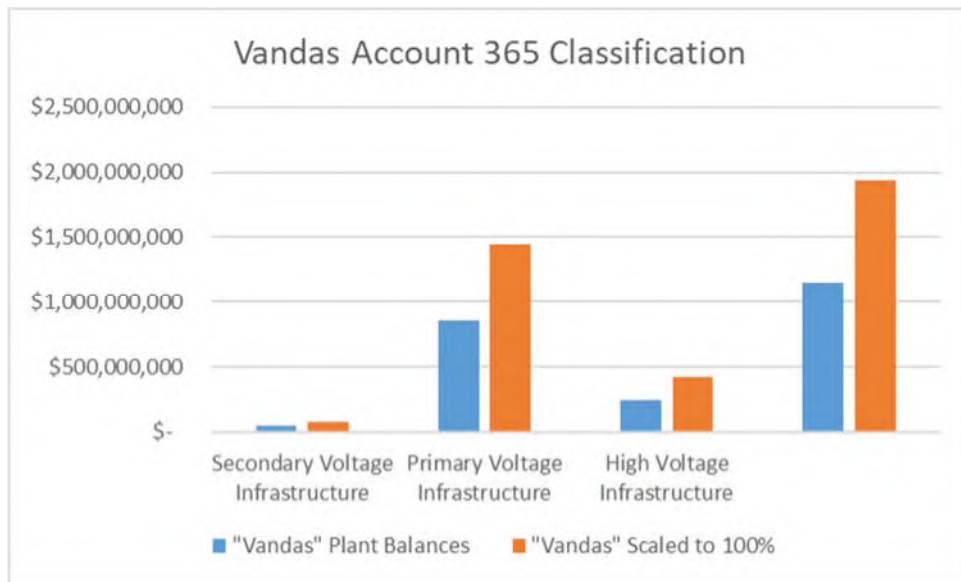
19          Q.     What do you mean by netting customer-allocated values from voltage-classified  
20 amounts?

21          A.     An example using Account 365 Overhead Conductors and Devices,  
22 Mr. Hickman's direct-filed CCoS workpaper, at the tab "A.F.vandas" provides the following  
23 classification percentages for Account 365 by voltage (note, these do not sum to 100%):

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11

<b>VANDAS STUDY RESULTS</b>							
					HV	PRI	SEC
					HV	PRI	SEC
364	poles & fixtures			poles & fixtures	0.198862	0.38202	0.194765
365	wires & devices			wires & devices	0.128273	0.443554	0.023287
366	conduit			conduit	0.028254	0.203557	0.089784
367	cable & devices			cable & devices	0.028254	0.203557	0.089784
368	line transformers				0	0.002837	0.426474

By multiplying the “Vandas” Account 365 classifiers with the Account 365 balance, we derive the following values of plant for each type of infrastructure, both using the provided raw values quoted above, and after scaling these classifiers to allocate 100% of the plant balance:

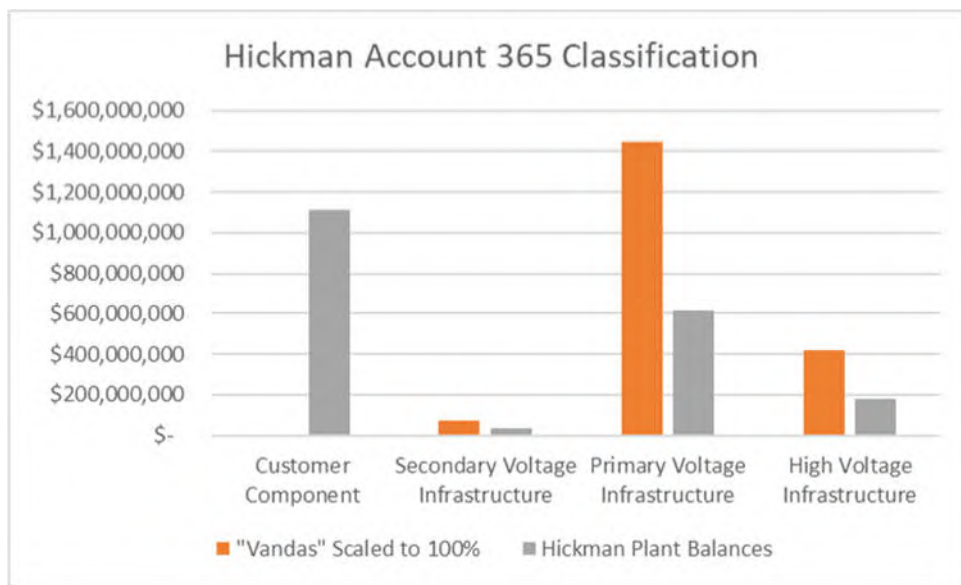


However, when he incorporates these results into his CCoS Study to classify the values in each account, he scales these numbers to produce 100% by account while holding his separately-determined minimum-size component percent constant, on the “COST Inputs” tab, as shown below, using Account 365 as an example:

Rebuttal Testimony of  
Sarah L.K. Lange

365	OVERHEAD CONDUCTOR						
	CUSTOMER	\$ 1,937,124	0.5731	\$ 1,110,166	0.1361	\$ 1,110,166	
	HV	\$ 1,937,124	1.0000	\$ 178,215	0.0218	\$ 178,215	
	PRIMARY	\$ 1,937,124	1.0000	\$ 616,393	0.0756	\$ 616,393	
	SECONDARY	\$ 1,937,124	1.0000	\$ 32,350	0.0040	\$ 32,350	
	SUBTOTAL 365			\$ 1,937,124		\$ 1,937,124	

By multiplying Mr. Hickman’s Account 365 classifiers with the Account 365 balance, we derive the following values of plant for each type of infrastructure:



However, in the interim, Mr. Hickman made his determination that \$329,586,296 of the infrastructure in Account 365 that operates at primary voltage should be classified as Customer-Related. Therefore, it is not appropriate to net this balance equally across the “Vandas”-determined voltage classifications, rather, the customer-related balance should be netted against voltage balances from lowest-voltage to highest-voltage, because we know that the minimum-size component was derived from a study of primary-voltage infrastructure.<sup>8</sup>

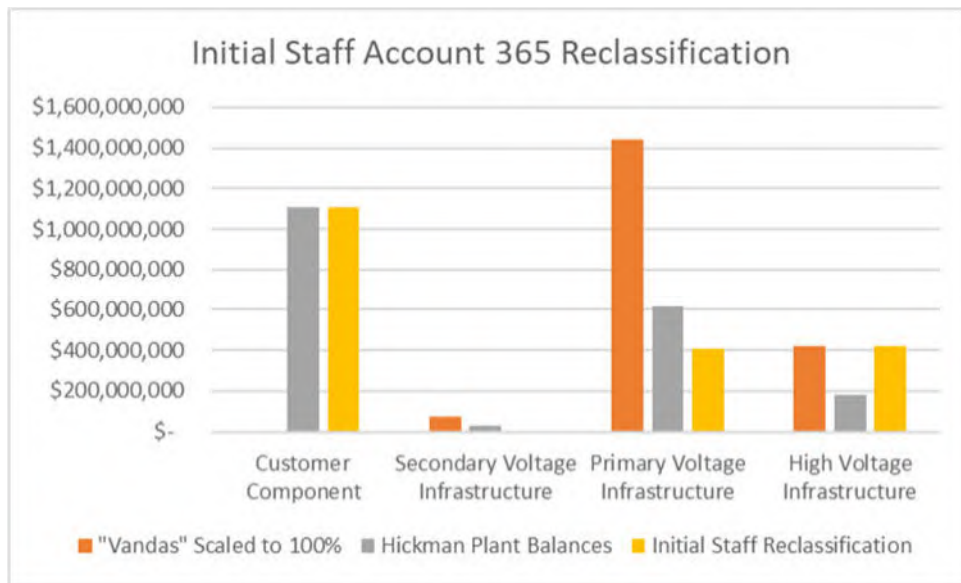
<sup>8</sup> Because Mr. Hickman ignored secondary-voltage infrastructure in Accounts 364-367 to the extent such infrastructure is present in his performance of his minimum-size study, it is reasonable to progressively net the minimum-system value against first secondary, then primary, then high voltage infrastructure balances.

1 Q. If the customer component is sequentially netted from first the secondary voltage  
2 infrastructure balance, then the primary voltage infrastructure balance, then the high voltage  
3 infrastructure balance, what are the resulting classified plant balances for Accounts 364 – 365?

4 A. A table providing all reclassified balances using Mr. Hickman’s customer  
5 classification values is provided below:

	Account 364	Account 365	Account 366	Account 367
Classified as Customer	\$ 832,734,238	\$ 1,110,165,707	\$ 190,517,446	\$ 306,710,820
HV	\$ 560,973,988.83	\$ 826,958,192.91	\$ 468,770,077.96	\$ 754,665,034.03
PRIMARY	\$ -	\$ -	\$ 4,074,058	\$ 6,558,757
SECONDARY	\$ -	\$ -	\$ -	\$ -

6  
7  
8 A comparison of the initial Staff reclassification and the “Vandas” and Hickman classifications  
9 is provided below:



11  
12 Q. What effect does this reclassification correcting Mr. Hickman’s netting of  
13 customer costs from Accounts 364-367 have on the level of rate base directly allocated to each  
14 customer class in the Ameren Missouri study?



1           A.       Correction of this error in the Ameren Missouri study results in the changes in  
2 directly-allocated rate base responsibility indicated below:

3

	RESIDENTIAL	SGS	LGS & SPS	LPS	LIGHTING
Ameren Rate Base Direct Allocation	62.88%	12.60%	19.92%	2.91%	1.69%
Cumulative Minimum System	62.34%	12.48%	20.22%	3.28%	1.68%
Change	-0.54%	-0.13%	0.30%	0.38%	-0.01%

4

5           Q.       Why would it be more reasonable under the circumstances of the Ameren  
6 Missouri study approach to weight customer counts by demand?

7           A.       It is necessary to weight customer counts by demand in the context of the  
8 Ameren Missouri study approach because Ameren Missouri used primary plant components as  
9 the foundation of its minimum size study, despite the fact that primary voltage infrastructure is  
10 significantly oversized for service to the majority of Ameren Missouri's customers.

11           Regarding weighting customer counts by demand, at page 98 of the NARUC Manual  
12 the following discussion is presented:

13                   While customer allocation factors should be weighted to offset  
14 differences among various types of customers, highly refined weighting  
15 factors or detailed and time consuming studies may not seem  
16 worthwhile. **Such factors applied in this final step of the cost study  
17 may affect the final results much less than such basic assumptions as  
18 the demand-allocation method or the technique for determining  
19 demand-customer classifications. [Emphasis added.]**

20           Essentially, this language condones use of customer weighting to address Ameren  
21 Missouri's failure to perform a minimum size study that is based on what anyone could  
22 reasonably consider the minimum size of infrastructure necessary to provide service to  
23 customers, but that it would be better to not make unreasonable assumptions to begin with.

24           Q.       How may one weight classes to lessen the unreliability of the Ameren Missouri  
25 study?

1 A. The most apparent weighting method using the data available in this case is to  
2 find the peak hour for each sample customer from the DR No. 0201 sample data, average those  
3 peaks for each class, adjust the classes to a consistent voltage, and rely on the relationship  
4 among classes of the average peak hour to weight the number of customers in each class.

5 Q. What is the relationship among classes of the average peak hour?

6 A. The loss-adjusted maximum peak hour by class from the customer sample, along  
7 with the average peak hour and minimum peak hour are all provided below. The relationship  
8 of each class's average peak hour to the residential class average peak hour is also provided  
9 below:

	<u>Residential</u>	<u>SGS</u>	<u>LGS</u>	<u>SPS</u>	<u>LPS Primary</u>	<u>LPS Sub</u>	<u>LPS Trans</u>
Ratio to Residential Average Peak Hour	1.00	1.88	41	127	872	1,064	1,486
Minimum Peak Hour in Sample	0.99	0.29	3.49	24	3,606	3,669	8,504
Average Peak Hour in Sample	10.07	18.94	412	1,282	8,775	10,715	14,960
Maximum Peak Hour in Sample	21.75	85.54	1,804	6,416	21,593	32,294	28,537

10  
11  
12 This means that the average SGS customer has a demand not quite twice that of the  
13 average residential customer, and that the average LPS customer served at transmission voltage  
14 is not quite 1,500 times the size of a residential customer. As a practical matter, what this means  
15 is that since the minimum size used by Ameren Missouri for component infrastructure operates  
16 at primary voltage, if those components are to be used for determining the "customer" portion  
17 for all classes, the customer counts by class should be weighted by the relationship of the  
18 class average maximum hour to the Small Primary Service (SPS) class average maximum hour,  
19 provided below:

	<u>Residential</u>	<u>SGS</u>	<u>LGS</u>	<u>SPS</u>	<u>LPS Primary</u>	<u>LPS Sub</u>	<u>LPS Trans</u>
Ratio to SPS Average Peak Hour	0.0079	0.0148	0.3216	1.0000	6.85	8.36	11.67
Minimum Peak Hour in Sample	0.99	0.29	3.49	24	3,606	3,669	8,504
Average Peak Hour in Sample	10.07	18.94	412	1,282	8,775	10,715	14,960
Maximum Peak Hour in Sample	21.75	85.54	1,804	6,416	21,593	32,294	28,537

1 All discussed values for the LPS customers by voltage, and aggregated at class level, are  
2 provided below:

	<u>LPS Primary</u>	<u>LPS Sub</u>	<u>LPS Trans</u>	<u>LPS Aggregate</u>
Ratio to Residential Average Peak Hour	872	1,064	1,486	1,004
Ratio to SPS Average Peak Hour	6.85	8.36	11.67	7.89
Minimum Peak Hour in Sample	3,606	3,669	8,504	3,606
Average Peak Hour in Sample	8,775	10,715	14,960	10,111
Maximum Peak Hour in Sample	21,593	32,294	28,537	32,294

5 All discussed values for the consolidation of LGS and SPS customers for study purposes are  
6 provided below:

	<u>LGS</u>	<u>SPS</u>	<u>LGS/SPS</u>
Ratio to Residential Average Peak Hour	41	127	46
Ratio to SPS Average Peak Hour	0.3216	1.0000	0.36
Minimum Peak Hour in Sample	3.49	24	3.5
Average Peak Hour in Sample	412	1,282	464
Maximum Peak Hour in Sample	1,804	6,416	6,416

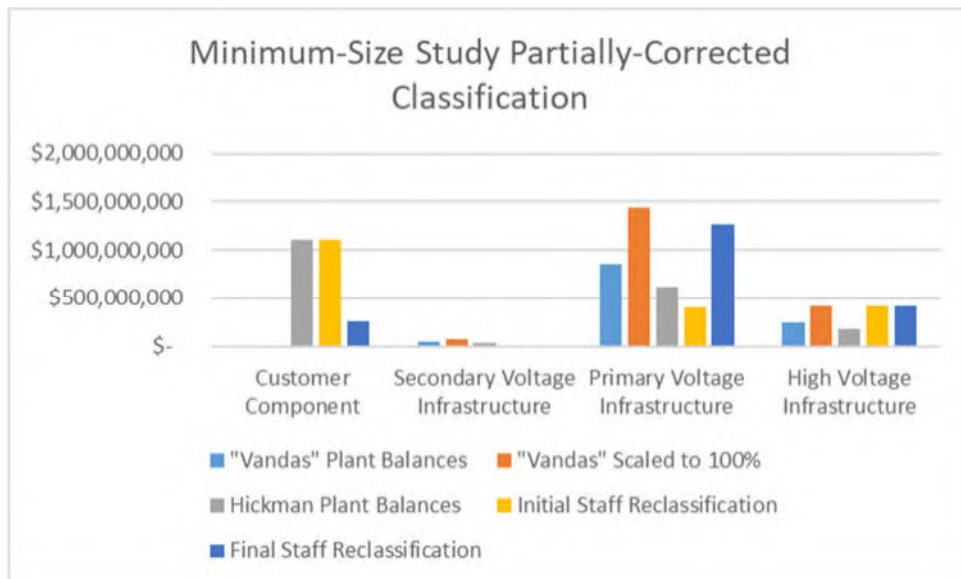
9 Q. What effect does the correction of the customer allocator to a weighted customer  
10 allocator for the distribution accounts have on the level of rate base directly allocated to each  
11 customer class in the Ameren Missouri study?

12 A. Correction of this error in the Ameren Missouri study results in the changes in  
13 directly-allocated rate base responsibility indicated below, including the correction of the  
14 cumulative netting issue discussed above:

	<u>RESIDENTIAL</u>	<u>SGS</u>	<u>LGS &amp; SPS</u>	<u>LPS</u>	<u>LIGHTING</u>
Ameren Rate Base Direct Allocation	62.88%	12.60%	19.92%	2.91%	1.69%
Cumulative Minimum System	62.34%	12.48%	20.22%	3.28%	1.68%
Weighted Customer Counts	53.35%	13.27%	27.91%	4.24%	1.22%
Change from Cumulative Minimum System	-8.99%	0.80%	7.69%	0.96%	-0.46%

1 Q. Did you perform any other adjustments to the directly-allocated distribution  
2 plant portion of the Ameren Missouri study?

3 A. Yes. I corrected the minimum-size calculation to remove devices from the  
4 calculation of the minimum system value of Accounts 365 and 367, note, the 366 classification  
5 relies on the classification of Account 367. In this process, the cumulative minimum system  
6 step is recalculated using the new, lower minimum-size classified balance. The revised  
7 classifications for the Account 365 example are provided below:



9  
10 Q. What is the shift in revenue requirement associated with corrections described  
11 above of the directly-allocated distribution net rate base?

12 A. Addressing these errors as described above results in the shifts in allocated rate  
13 base provided below, and the shifts in return on rate base using the Ameren Missouri study  
14 capital costs as indicated below:

	RESIDENTIAL	SGS	LGS & SPS	LPS	LIGHTING
Direct-allocated Net Rate Base Difference	\$ (446,770,556)	\$ 18,967,876	\$ 401,899,563	\$ 61,328,949	\$ (35,425,833)
Direct-allocated Rate Base RoR Difference	\$ (32,104,932)	\$ 1,363,032	\$ 28,880,503	\$ 4,407,098	\$ (2,545,700)

1 This does not include any expense allocation, property tax allocation, overhead/general  
2 allocation, or income tax allocation. The general direction of these other items should be  
3 expected to follow the direction and relative magnitude of the shifts provided above.

4 Q. Did you attempt to estimate the expense impact of these corrections?

5 A. Yes. Because Ameren Missouri relies on its allocation of distribution rate base  
6 to allocate distribution expense, addressing the errors described above will result in changes in  
7 the allocated distribution expense, which in turn is used to develop additional indirect allocators  
8 for labor-related costs and overheads such as general expenses. An estimate of the corrected  
9 distribution operations and maintenance expense (not including property taxes, benefits,  
10 general expense, or other items indirectly allocated off of distribution rate base or distribution  
11 expense) is provided below, along with an estimate of the combination of the overall revenue  
12 requirement impact in the context of the Ameren Missouri study (not including income or  
13 property tax, benefits, PISA, general expense, or any other costs or expenses):

14

	<b>RESIDENTIAL</b>	<b>SGS</b>	<b>LGS &amp; SPS</b>	<b>LPS</b>	<b>LIGHTING</b>
Direct-allocated Rate Base RoR Difference	\$ (32,104,932)	\$ 1,363,032	\$ 28,880,503	\$ 4,407,098	\$ (2,545,700)
Estimate of Initial Expense Difference	\$ (13,341,488)	\$ 984,164	\$ 15,123,175	\$ 1,342,167	\$ (4,136,520)
Minimum Estimated RR Difference	\$ (45,446,421)	\$ 2,347,196	\$ 44,003,678	\$ 5,749,266	\$ (6,682,220)

15

16 Q. With the above adjustments, is the Ameren Missouri CCoS Study allocation of  
17 distribution plant and expenses reasonable?

18 A. No. Ameren Missouri's study remains unacceptably deficient due to the failure  
19 to address customer-specific infrastructure that is recorded in Accounts 364-368, and due to the  
20 general inapplicability of the minimum-size approach to a primary-based system. Further, the  
21 minimum-size approach predates the modern "smart grid" which is more appropriately

1 allocated using the weighted hour method provided in the Staff study, which is also more  
2 compatible with rate structure modernization.

### 3 **Combined Adjustments to Ameren Missouri Study**

4 Q. What are the results of the Ameren Missouri study adjusted for the indicated  
5 changes to production and distribution allocation discussed above?

6 A. The combined impact of the adjustments discussed above results in the Ameren  
7 Missouri CCoS Study results provided below, at the Ameren Missouri requested Rate of Return,  
8 and at the Staff recommended Rate of Return:

	Residential	SGS	LGS & SPS	LPS	Lighting
<b>Reallocated Ratebase P &amp; D</b>	\$ (463,422,773)	\$ 16,001,145	\$ 413,503,381	\$ 61,328,949	\$ (27,700,160)
<b>Production Depreciation Change:</b>	\$ (5,999,430)	\$ (1,068,848)	\$ 4,180,602	\$ -	\$ 2,783,391
<b>Distribution Depreciation Change:</b>	\$ (21,905,808)	\$ 930,022	\$ 19,705,718	\$ 3,007,047	\$ (1,736,980)
<b>Adjusted Operating Income:</b>	\$ 295,434,401	\$ 67,580,977	\$ 168,363,102	\$ 56,073,337	\$ 10,495,816
<b>Adjusted Rate Base:</b>	\$ 5,883,974,083	\$ 1,380,989,621	\$ 3,435,629,771	\$ 729,788,087	\$ 175,108,105
<b>Ameren Study RoR:</b>	3.8463%	4.8818%	7.0935%	9.0391%	5.9500%
<b>Return at Ameren Requested RoR:</b>	\$ 422,822,378	\$ 99,237,914	\$ 246,884,355	\$ 52,442,572	\$ 12,583,268
<b>Return at Staff-Recommended RoR:</b>	\$ 403,758,302	\$ 94,763,508	\$ 235,752,915	\$ 50,078,059	\$ 12,015,918
<b>Rate Revenue:</b>	\$ 1,373,009,870	\$ 305,323,309	\$ 791,487,157	\$ 205,820,662	\$ 41,943,896
<b>Revenue Available for RoR (Ameren):</b>	\$ 295,434,401	\$ 67,580,977	\$ 168,363,102	\$ 56,073,337	\$ 10,495,816
<b>Revenue Available for RoR (Staff):</b>	\$ 314,498,477	\$ 72,055,383	\$ 179,494,542	\$ 58,437,851	\$ 11,063,166
<b>Under/(Over) Contribution (Ameren) \$:</b>	\$ 127,387,977	\$ 31,656,937	\$ 78,521,254	\$ (3,630,765)	\$ 2,087,452
<b>Under/(Over) Contribution (Staff) \$:</b>	\$ 89,259,825	\$ 22,708,124	\$ 56,258,373	\$ (8,359,792)	\$ 952,752
<b>Under/(Over) Contribution (Ameren) %:</b>	9.3%	10.4%	9.9%	-1.8%	5.0%
<b>Under/(Over) Contribution (Staff) %:</b>	6.5%	7.4%	7.1%	-4.1%	2.3%

11 Note, these adjustments do not attempt to account for the reallocation of property tax, income  
12 tax, PISA, general plant, general expense, labor benefits, or any other item of cost or expense  
13 not explicitly identified above. These results also reflect Ameren Missouri's reliance on  
14 the A&E allocation method for its production fleet, which is inappropriate for  
15 current circumstances, Ameren Missouri's failure to match the costs and revenues of its low  
16 and no variable cost generation, and Ameren Missouri's failure to properly classify the  
17 customer-specific infrastructure.

1 Q. What revenue neutral shifts, if any, do these results suggest as appropriate  
2 resolution of the intraclass revenue requirement issue?

3 A. As is, these results suggest that it would be reasonable to hold the lighting class  
4 revenue requirement constant, and to apply an equal percent increase to the revenue  
5 requirements of all other classes.<sup>9</sup>

6 Q. Based on your knowledge and judgment, if Ameren Missouri's failure to match  
7 the costs and revenues of its low and no variable cost generation, and Ameren Missouri's failure  
8 to properly classify the customer-specific infrastructure were addressed, what results would you  
9 expect?

10 A. If in addition to the adjustments already reflected, these failures were addressed,  
11 I would expect the Ameren Missouri study results to be generally consistent with the Staff study  
12 results.

### 13 **RESIDENTIAL RATE DESIGN**

#### 14 **Residential Customer Charges**

15 Q. At page 22, Mr. Wills testifies that "[t]he costs of assets dedicated to individual  
16 customers, such as meters and service lines that directly connect to the customer premises and  
17 billing costs, are classified as customer-related costs. Beyond the basic costs of customer  
18 connections and billing, the costs of the minimum distribution system are included in the  
19 customer-related classification...." Is this accurate?

20 A. This is not accurate to recent Ameren Missouri rate cases, under which the  
21 customer-classified distribution costs in most distribution accounts have not been included in

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<sup>9</sup> As noted above, I do not object to holding the company-owned lighting rates constant while increasing the customer-owned lighting rates, based on that single aspect of the Ameren Missouri study.

1 the customer charge calculation when this issue was most recently litigated. The Commission  
2 included as a finding of fact in the Commission's Report and Order in ER-2014-0258 at page 75  
3 that:

4 Customer-related costs are the minimum costs necessary to make electric  
5 service available to the customer, regardless of how much electricity the  
6 customer uses. Examples include meter reading, billing, postage,  
7 customer account service, and a portion of the costs associated with  
8 required investment in a meter, the service line drop, and other billing  
9 costs. Customer-related costs are generally recovered through the  
10 customer charge while other costs are recovered through volumetric rates  
11 that vary with the amount of electricity used.

12 As discussed above, the Ameren Missouri "minimum-size" classification relied upon  
13 by Mr. Hickman is unreliable and inconsistent with the NARUC Manual.

14 Q. Is there agreement among the parties on the value of the cost of service  
15 reasonably allocated to the residential customer charge?

16 A. In short, no. Staff relies on the basic customer method of cost causation, which  
17 holds that the customer charge should include (1) the costs and expenses of metering and billing  
18 customers, (2) the cost of the infrastructure that varies with the number of customers served,  
19 including related income taxes, and (3) the proportionate labor, non-labor, and distribution  
20 expense associated with the infrastructure. In this case for its calculation, Staff also included  
21 additional customer service expenses, and also included approximately \$11.9 million of the  
22 functionalized "Other/General" revenue requirement out of an abundance of caution. However,  
23 Ameren Missouri exceeds this allocation in two main ways. First, Ameren Missouri includes  
24 as "customer-related" its entire minimum-size distribution costs and expense calculation, and  
25 second, the Ameren Missouri minimum-size distribution calculation is poorly calculated.  
26 In other words, Ameren Missouri errs in making the decision to include this category of



1 revenue requirement, but even if it were reasonable to include it, Ameren Missouri's calculation  
2 is wrong.<sup>10</sup>

3 Q. Ameren Missouri requests increasing the customer charges for most residential  
4 customer rate plans to \$13. Is this reasonable?

5 A. No. Ameren Missouri bases this request on finding the cost for rebuilding every  
6 inch of its distribution system at primary voltage, including every device, and then deciding  
7 each customer in each class should pay the same share of that total.

#### 8 **Ultimate Saver and Smart Saver Discounted Customer Charges**

9 Q. What rationale does Ameren Missouri express for its position to maintain a \$9.00  
10 customer charge on the "Ultimate Savers" plan and implementing an \$11.00 customer charge  
11 on its "Smart Savers" plan?

12 A. Beyond stating that the Smart Savers is "the second most cost-reflective rate  
13 offered by the Company based on my analysis from the 2019 case," at page 24, Mr. Wills offers  
14 no real defense of the requested discount to the Smart Savers plan customer charge as compared  
15 to the \$13.00 customer charge requested for other residential customers.

16 Regarding the Ultimate Savers plan, Mr. Wills accurately testifies at page 23 that the  
17 Ultimate Savers plan rate structure includes a demand charge. A well-designed cost-reflective  
18 demand charge may recover some or all of the revenue requirement associated with the  
19 infrastructure that Mr. Wills argues should be included in the customer charge.

20 Q. Is the Ultimate Savers plan demand charge cost-reflective?

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<sup>10</sup> The only other witness to provide testimony on this issue is Ms. Hutchinson, who recommends at page 11 to retain the current \$9.00 customer charge. At page 13 she states "Ideally, the rate design for residential customers should include a fixed charge that is based on nothing more than the cost of the meter, customer service, and the line to the dwelling."

1           A.     No. None of the opt-in ToU plans are well-designed, and the Ultimate Savers  
2 demand charge is not cost-reflective. However, in the absence of the specific design of the  
3 Ultimate Savers rate plan, and if the structure of the Ultimate Savers rate plan were the basis of  
4 the default residential rate structure, it is accurate to say that a demand charge may reasonably  
5 incorporate some of the revenue recovery associated with the infrastructure Ameren Missouri  
6 has shoe-horned into its customer charge calculation.

7           Q.     Even if there were a cost-based reason to do so, is it reasonable to reduce the  
8 customer charge for Ultimate Savers rate plan, relative to other residential rate plans, under the  
9 circumstances of this case?

10          A.     No. Unfortunately, Ameren Missouri markets its most sophisticated rate plan  
11 under which participants bear the risk of the highest bill as “Ultimate Savers,” and its least risky  
12 plan from a customer perspective as “Anytime Users.” There is a very real risk that customers  
13 will perceive the plans as exactly the opposite of their relative risks, especially if “Ultimate  
14 Savers” is presented as having the lowest fixed monthly bill in Ameren Missouri’s marketing  
15 efforts. Staff recommends that all customer charges for all residential rate plans be held at the  
16 current \$9.00 level, and that the Ultimate Saver and Smart Saver customer charges not be  
17 discounted.

18          Q.     If a relatively low customer charge is authorized for the “Ultimate Savers” plan,  
19 would it be reasonable to require a minimum bill?

20          A.     Yes. If against Staff’s primary recommendation the customer charge for the  
21 Ultimate Saver plan is discounted relative to other rate plans, Staff recommends that a minimum  
22 demand charge equal to the difference in the customer charges be incorporated into the rate  
23 structure. This should be plainly disclosed in all relevant marketing and education materials.

1 Note, the Smart Savers plan does not include a demand charge, and there is no basis for its  
2 customer charge to differ from those of other residential rate plans which also do not include a  
3 demand charge.

#### 4 **Opt-in ToU Rate Plans**

5 Q. Are any of the opt-in ToU rate plans, as currently designed, reasonable for use  
6 as a default residential rate schedule?

7 A. No. These rates are not cost-based, and would cause significant customer impact  
8 for those customers who are unable to rapidly respond to the price differentials in the plans.

9 Q. At page 20 Mr. Wills testifies about,

10 ...changes in the electric utility industry that are driving the need for,  
11 and the capability of utilities to offer, updated modern rate plans that  
12 better reflect the cost structure of the utility. Those changes include  
13 adoption of electric vehicles ("EVs"), increasing penetration of  
14 intermittent **renewable generation** (both **behind the meter** and at utility  
15 scale), and technologies like smart thermostats and other home  
16 automation that increase customers' ability to control their electric usage.  
17 Additionally, **battery technology continues to evolve and may become**  
18 **increasingly economic for customers to deploy in their homes –**  
19 **paired with solar generation or on its own** – in the not-too-distant  
20 future. These changes are increasingly familiar to the Commission and  
21 stakeholders. On the utility side, deployment of AMI systems is enabling  
22 the billing and communications capabilities needed to offer such rates  
23 and help customers succeed on them. With the increasing prevalence of  
24 such new energy-related technologies, many of which can represent  
25 significant investments on the part of customers, and which can also have  
26 significant impacts on the way customers interact with the electric grid  
27 and may correspondingly cause different costs to be incurred or avoided  
28 by the utility, it is increasingly important for electric rates to reflect the  
29 cost structure of the utility. Cost-based rates help to promote equity  
30 between customers and also promote economic efficiency of the electric  
31 system. These are two of the important goals of electric rate design  
32 originally spelled out by the widely recognized and often cited rate  
33 design authority Dr. James C. Bonbright in his *Principles of Public*  
34 *Utility Rates*

1           The modern rates that the Company has now introduced feature price  
2 signals that are **intended to encourage decisions around the adoption**  
3 **of the technologies I described above by customers in a manner that**  
4 **promotes the economic efficiency of the electric system.** Once  
5 adopted, it promotes fairness between customers where the bills of  
6 customers choosing these new technologies reasonably reflect the cost  
7 of serving them, avoiding the creation of undue cross-subsidies between  
8 customers.” **[Emphasis added.]**

9           Does Ameren Missouri allow rooftop solar customers with net metering to participate in its  
10 opt-in ToU rates?

11           A.     No.

12           Q.     Does Ameren Missouri allow customers who own batteries to participate in its  
13 opt-in ToU rates to arbitrage energy prices?

14           A.     No. Because net metering customers are barred from participation in the opt-in  
15 ToU rate plans, customers are unable to store energy in their own batteries to discharge at times  
16 of higher energy prices.

17           Q.     Is Ameren Missouri proposing to allow either of these as an outcome of this  
18 case?

19           A.     No.

20           Q.     Would it be good regulatory practice to use any of the opt-in rate plans for a  
21 default rate structure at this time?

22           A.     No.

### 23           **Default Time of Use Rate Plan**

24           Q.     At page 13 Ms. Hutchinson testifies “Ameren Missouri should no longer be  
25 allowed to automatically place consumers on a rate plan, unless a consumer opts out of that  
26 plan (“Opting- Out”), i.e., with regard to time-of-use utility rates. While Consumers Council is

1 not opposed to time of use utility rates, and thinks they are a useful tool to help achieve energy  
2 efficiency, we recommend that consumers not be switched to any new rate plan without  
3 affirmatively consenting to the switch (“Opting-In”).”

4 Do you agree?

5 A. No. The integration of time-based elements into the rate structure of Ameren  
6 Missouri is a necessary process. Just as a customer would not opt-in to a rate increase at the  
7 conclusion of a rate case, at this time it is no longer reasonable to allow customers to opt-out of  
8 rate modernization.

9 Q. What is the basis of Ms. Hutchinson’s concern?

10 A. At pages 20-21 Ms. Hutchinson references a letter she received a copy of and  
11 states:

12 Ameren is currently offering a variety of new rate options to customers,  
13 and Consumers Council is pleased that consumers have such options, as  
14 different rate plans could result in substantial savings, if they fit a  
15 particular customer’s lifestyle. However, Consumers Council is  
16 concerned that the policy of switching electric consumers to “Opt-Out”  
17 plans should not be permitted in the future. Consumers should ideally  
18 never be switched to another rate plan without giving their clear  
19 affirmative consent.

20 Based on an agreement in the previous rate case, Ameren Missouri will  
21 automatically switch a customer to an “Evening/Morning” time-of-use  
22 plan. Sometimes, despite the efforts to educate the consumer, the switch  
23 is made without the consumer realizing what has happened. The decision  
24 of rate plans has the potential to add additional costs, creates  
25 vulnerability for families with small children, working individuals who  
26 do not take time to read the inserts, those living with disabilities, and  
27 seniors.

28 It is Consumers Council’s recommendation that Ameren Missouri  
29 should continue to educate customers about the various rate plans, but  
30 should also require customers to affirm their desire to participate by  
31 “Opting-In” before a switch in rate plans is allowed.

32 A letter to the Public Service Commission was shared with Consumers  
33 Council. (Attachment 3 to this testimony). The letter is from an Ameren

1 customer who took no action and yet experienced a switch. The letter  
2 explains frustration with the “Opt-Out” requirement. Consumers Council  
3 is concerned that there may be many other similarly situated customers  
4 who do not know that they have been switched to a different rate.

5 The referenced letter discusses concern that the customer had to take action to stay on  
6 the current rate plan. What is your response?

7 A. In the furtherance of rate modernization and improvement of cost-based rates,  
8 the current rate plan is going away. Under Staff’s recommendation, the need (and ability) to  
9 take action to maintain the antiquated rate plan is obviated.

10 **NON-RESIDENTIAL RATE DESIGN**

11 **LGS & SPS Rate Design**

12 Q. At pages 35-36 Mr. Chriss requests,

13 For the purposes of this docket, at the Company’s proposed revenue  
14 requirement for the LGS and SP classes, MECG recommends that the  
15 Commission:1) Accept Ameren’s proposed customer charges and  
16 on-peak and off-peak adjusters for both LGS and SP, and Ameren’s  
17 proposed Rider B credits and reactive charge for SP; 2) Increase the  
18 summer and winter demand charges for LGS and SP by one and one-half  
19 times the approved percent class increases; and 3) Apply the remaining  
20 proposed increase on an equal percentage basis to the summer and winter  
21 energy charges.... ...If the Commission awards an increase for these  
22 classes that is lower than that proposed by the Company, the  
23 Commission can then take larger steps to address the over-recovery of  
24 demand-related costs through energy charges and associated intra-class  
25 subsidies. Specifically, the Commission should set the demand charges  
26 per MECG’s recommendation above and apply the approved reduction  
27 in the class revenue requirement by reducing all base rate energy charges  
28 on an equal percentage basis.

29 Do you agree?

30 A. No. Mr. Chriss’s recommendations are based on the unreliable Ameren Missouri  
31 study. Even if the study were reliable, Mr. Chriss’s recommended shifts assume an

1 unreasonable level of precision and accuracy in the results for any CCoS. Finally, Mr. Chriss’s  
2 intraclass discussion is fundamentally inaccurate, and again, based on the unreliable Ameren  
3 Missouri study.

4 Q. At pages 29 – 30 Mr. Chriss testifies as to his understanding that  
5 “only 14 percent of LGS revenues and 10 percent of SP revenues are collected through demand  
6 costs. Further demonstrating this problem, while 20.4 percent of LGS / SP costs are energy  
7 related, 83.6 percent of LGS revenues and 88.8 percent of SP revenues are collected through  
8 energy charges.” Is this description accurate?

9 A. No. Mr. Chriss’s understanding is not an accurate reflection of bill calculation  
10 for customers on an hours’ use rate structure like that in use for the LGS and SPS rate  
11 schedules.<sup>11</sup> The rate a customer pays for energy in a given month is a product of that  
12 customer’s demand in that month, or of a seasonal demand determinant which may apply to  
13 lower that customer’s bill. For example, the LGS summer first block rate is \$0.1054/kWh,  
14 while the summer LGS tail block rate is \$0.0534/kWh. Therefore, the difference of \$0.052/kWh  
15 (49% of the first block charge) is billed based on a demand determinant. Using Mr. Harding’s  
16 rate design workpaper and the Ameren Missouri billing determinants, the values for the  
17 Customer, Demand, and Energy portions of the LGS and SPS rate revenues are provided below:

18

	<b>LGS \$</b>	<b>SPS \$</b>	<b>LGS %</b>	<b>SPS %</b>
<b>Customer</b>	\$ 13,473,902	\$ 2,831,384	2.42%	1.47%
<b>Demand</b>	\$ 224,901,090	\$ 64,455,937	40.37%	33.44%
<b>Energy</b>	\$ 318,660,683	\$ 125,482,807	57.21%	65.09%

19

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<sup>11</sup> Staff does not endorse Mr. Chriss’s representation of the valuation of the energy or demand revenue requirements for the SPS and LGS classes, but as Staff’s recommendation in this case is intended to reduce customer impact to facilitate implementation of ToU Rate Structures, Staff has not performed a detailed study of ideal costing for the current rate structure.

1           **Special Rate Structures for EV Charging**

2           Q.     At pages 36 – 37 Mr. Chriss requests:

3                     [T]he Commission should require Ameren to create alternative optional  
4                     LGS (“LGS-EV”) and SP (“SP-EV”) rates for EV charging customers  
5                     with load sizes that would qualify to take service on LGS or SP rates.  
6                     These alternatives could then serve as a basis from which the Company  
7                     and stakeholders can design durable EV charging rate schedules in the  
8                     rate redesign process....

9                     ...For the purposes of this docket, MECG proposes to reallocate the  
10                    summer demand charge revenue requirement to the first block of the  
11                    summer energy rate and reallocate the winter demand charge revenue  
12                    requirement to the first block of the winter energy rate. This reallocation  
13                    would serve two purposes: first, it would reduce the barrier to entry for  
14                    very low usage EV chargers versus LGS and SP’s demand charges; and  
15                    second, it would recover the demand charge revenue requirements in the  
16                    low load factor first blocks (up to 20.8 percent monthly load factor),  
17                    which would provide more meaningful fixed cost recovery than  
18                    spreading demand charge revenue across the three energy blocks.

19           Should the proposed rate schedules be created?

20           A.     No.

21           Q.     If implemented, what would the impact of this proposal be on the level of  
22           accretive earnings assumed to justify ratepayer funding of the Ameren Missouri Charge Ahead  
23           portfolio of subsidies to EV-charging customers?

24           A.     This proposal would substantially reduce the accretive earnings assumed in  
25           justifying the Charge Ahead portfolio.

26           Q.     Is this proposal cost-based?

27           A.     No. Mr. Chriss moves dollars and determinants around to the benefit of an  
28           assumed load shape, without any regard for cost-causation.

29           Q.     Is it likely that any customer with a high demand and low load factor,  
30           such as welding shops, smelters, grain dryers, millers and other customers currently served on



1 the LGS, SPS, and LPS rate schedules would prefer to avoid the demand charges that  
2 Mr. Chriss references?

3 A. Any customer with a low load factor or a high demand contributes more revenue  
4 per kWh than customers with a high load factor or a low demand under the current Ameren  
5 Missouri rate designs for these schedules. These customers may or may not cause more costs  
6 than one another. The solution is not the creation of a multitude of specialty end-use rates,  
7 rather the solution is rate schedule modernization as described in my direct testimony, which  
8 would align cost causation with revenue responsibility based on the actual time of energy  
9 consumption and the level of infrastructure required for customers.

10 **LPS Rate Design**

11 Q. What recommendations have been made by other parties concerning LPS rate  
12 design?

13 A. Mr. Brubaker on behalf of MIEC recommends that all of the charges, except for  
14 the Low-Income Pilot Program Charge, should receive the same percentage increase.<sup>12</sup>

15 Q. Do you agree with this recommendation?

16 A. Generally, yes. For customers with AMI metering, Staff recommended creation  
17 of a new rate schedule for LPS customers equipped with AMI metering that incorporates a  
18 time-based overlay into its rate structure, with current LPS rates adjusted on a equal percentage  
19 basis. For customers without AMI metering, Staff recommends equal percentage adjustment  
20 of all LPS rate elements, except for the Low-Income Pilot Program Charge. Note, Staff

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<sup>12</sup> Brubaker Direct page 4.

1 recommends that Rider B credits be held at the current level, and that Rider C credits be adjusted  
2 as described above.

3 **CONCLUSION**

4 Q. Does this conclude your rebuttal testimony?

5 A. Yes it does.

**BEFORE THE PUBLIC SERVICE COMMISSION**  
**OF THE STATE OF MISSOURI**

In the Matter of Union Electric Company            )  
d/b/a Ameren Missouri's Tariffs to Adjust        )  
Its Revenues for Electric Service                )     Case No. ER-2022-0337

**AFFIDAVIT OF SARAH L.K. LANGE**

STATE OF MISSOURI     )  
                                  )     ss.  
COUNTY OF COLE     )

**COMES NOW SARAH L.K. LANGE** and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Rebuttal Testimony of Sarah L.K. Lange*; and that the same is true and correct according to her best knowledge and belief.

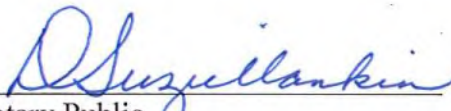
Further the Affiant sayeth not.

  
\_\_\_\_\_  
SARAH L.K. LANGE

**JURAT**

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 10<sup>th</sup> day of February 2023.

D. SUZIE MANKIN Notary Public - Notary Seal State of Missouri Commissioned for Cole County My Commission Expires: April 04, 2025 Commission Number: 12412070
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\_\_\_\_\_  
Notary Public

0145

Please fully quantify the company's estimated benefits of RESIDENTIAL - SMART SAVER SERVICE 1(M) 54.7, RESIDENTIAL - OVERNIGHT SAVER SERVICE 1(M) 54.10, and RESIDENTIAL - ULTIMATE SAVER SERVICE, separately; to the extent the utility has not prepared such an analysis, describe why the utility has not prepared such analysis. Please fully quantify the company's estimated net revenue change attributable to each RESIDENTIAL - SMART SAVER SERVICE 1(M) 54.7, RESIDENTIAL - OVERNIGHT SAVER SERVICE 1(M) 54.10, and RESIDENTIAL - ULTIMATE SAVER SERVICE, separately; to the extent the utility has not prepared such an analysis, describe why the utility has not prepared such analysis. Please provide each and every cost-benefit analysis the company, its consultants, or its affiliates have prepared for evaluation of RESIDENTIAL - SMART SAVER SERVICE 1(M) 54.7, RESIDENTIAL - OVERNIGHT SAVER SERVICE 1(M) 54.10, and RESIDENTIAL - ULTIMATE SAVER SERVICE, separately; to the extent such analyses have not been prepared, explain why and describe all factors to be evaluated in such analyses.

Response:

None of the requested analyses have been performed. The Company has indicated in testimony in both this case and in previous rate cases related to its TOU rate offerings that its initial goal in offering TOU rates was to provide customers with additional choice and control in managing their energy bills, to better align its rates and customer bills with the cost of serving those customers, and to build foundational capabilities in implementing, communicating about, and billing complex rates. The analyses described were not necessary to achieve these initial goals.

0144

Please fully explain what the Company considers successful implementation of opt-in time-based rate schedules, RESIDENTIAL - SMART SAVER SERVICE 1(M) 54.7, RESIDENTIAL - OVERNIGHT SAVER SERVICE 1(M) 54.10, and RESIDENTIAL - ULTIMATE SAVER SERVICE. Please indicate whether responses provided are applicable to individual rate schedules, or collectively. a. Please fully describe the costs or expenses and the timing of incurrence of costs and expenses that the Company projects to avoid or reduce due to what it considers successful implementation of opt-in time-based rate schedules. b. Please describe the distribution and substation infrastructure that can be prematurely retired if successful implementation of opt-in time-based rate schedules occurs, specifying the horizon of each retirement. c. Please describe the transmission and substation infrastructure that can be prematurely retired if successful implementation of opt-in time-based rate schedules occurs, specifying the horizon of each retirement. d. Please describe the generation infrastructure that can be prematurely retired if successful implementation of opt-in time-based rate schedules occurs, specifying the horizon of each retirement. e. Please describe the distribution and substation infrastructure that can be avoided or deferred if successful implementation of opt-in time-based rate schedules occurs, specifying the horizon of each avoided or deferred installation. f. Please describe the transmission and substation infrastructure that can be avoided or deferred if successful implementation of opt-in time-based rate schedules occurs, specifying the horizon of each avoided or deferred installation. g. Please describe the generation infrastructure that can be avoided or deferred if successful implementation of opt-in time-based rate schedules occurs, specifying the horizon of each avoided or deferred installation.

Response:

The Company considers that it has successfully implemented opt-in time-based rate schedules, inasmuch as the Company has developed and shared with eligible customers communications to inform and educate them about their rate options and how they work, developed high quality online tools for customers to compare their bills across rate options and monitor their usage in granular time increments in order to inform the management of their usage according to their TOU rate schedules parameters, and has made such TOU rate options available to all residential customers with an AMI meter. To date, over 1,300 residential customers have elected to take service on an optional TOU rate.

A. No such analysis has been performed

B. No infrastructure retirements have been identified associated with TOU rates, nor is it clear to the Company why implementation of TOU rates would be expected to result in the retirement of infrastructure.

C. No infrastructure retirements have been identified associated with TOU rates, nor is it clear to the Company why implementation of TOU rates would be expected to result in the retirement of infrastructure.

D. No infrastructure retirements have been identified associated with TOU rates, nor is it clear to the Company why implementation of TOU rates would be expected to result in the retirement of infrastructure.

E. Specific future investments in infrastructure that may be avoided as a result of TOU have not been identified, just as the demand side management programs run by the Company under MEEIA are assumed to result in long run distribution cost savings without the identification of specific infrastructure projects that are avoided. The expected value of avoided distribution costs associated with peak load reductions is estimated in the

Company's IRP. Such avoided costs are likely to apply to load reductions that result from TOU rate adoption. While rate adopters are expected to shift load resulting in peak load reductions, the ultimate amount of peak load reductions is not known, as it is a function of the level of rate adoption ultimately realized. The Company does not currently have forecasts or targets of adoption levels of its optional TOU rates with which to estimate avoided infrastructure costs in the future.

F. Specific future investments in infrastructure that may be avoided as a result of TOU have not been identified, just as the demand side management programs run by the Company under MEEIA are assumed to result in long run transmission cost savings without the identification of specific infrastructure projects that are avoided. The expected value of avoided transmission costs associated with peak load reductions is estimated in the Company's IRP. Such avoided costs are likely to apply to load reductions that result from TOU rate adoption. While rate adopters are expected to shift load resulting in peak load reductions, the ultimate amount of peak load reductions is not known, as it is a function of the level of rate adoption ultimately realized. The Company does not currently have forecasts or targets of adoption levels of its optional TOU rates with which to estimate avoided infrastructure costs in the future.

G. Specific future investments in infrastructure that may be avoided as a result of TOU have not been identified, just as the demand side management programs run by the Company under MEEIA are assumed to result in long run generation capacity cost savings without the identification of specific generation projects that are avoided. The expected value of avoided capacity costs associated with peak load reductions is estimated in the Company's IRP. Such avoided costs are likely to apply to load reductions that result from TOU rate adoption. While rate adopters are expected to shift load resulting in peak load reductions, the ultimate amount of peak load reductions is not known, as it is a function of the level of rate adoption ultimately realized. The Company does not currently have forecasts or targets of adoption levels of its optional TOU rates with which to estimate avoided infrastructure costs in the future.

0143

Please quantify any changes in existing residential load that the company projects to cause by continued operation of the "RESIDENTIAL - ULTIMATE SAVER SERVICE" rate schedule, including the timing of such projected changes. a. Please quantify any reduction in revenue requirement by account and by year that is expected to be caused by any changes identified in the first question, above. b. Please specify the amounts in part a that are included in the FAC base Factor and subject to adjustment through the FAC. c. If the estimates described above have not been prepared, please estimate the cost and time of preparing such estimate.

Response:

No such analysis has been performed. The ongoing Demand Side Management Market "DSM" Potential Study, and the Company's 2023 Integrated Resource Plan "IRP" will address the expected load impacts, either in aggregate for the Time of Use "TOU" rate program, or by individual TOU rate offering. The cost of such analysis is included in the cost of performing the DSM potential study Load Flexibility Analysis task, which the Statement of Work for the potential study identifies as costing \$49,560. However, the TOU analysis is a subset of that task, so not all of the cost may be attributable to TOU. The timing of such analysis is aligned with the 2023 IRP filing.

0142

Please quantify any changes in projected residential load that the company projects to cause by Implementation of the RESIDENTIAL - OVERNIGHT SAVER SERVICE rate schedule, including the timing of such projected changes. a. Please quantify any reduction in revenue requirement by account and by year that is expected to be caused by any changes identified in the first question, above. b. Please specify the amounts in part a that are included in the FAC base Factor and subject to adjustment through the FAC. c. If the estimates described above have not been prepared, please estimate the cost and time of preparing such estimate.

Response:

No such analysis has been performed. The ongoing Demand Side Management Market "DSM" Potential Study, and the Company's 2023 Integrated Resource Plan "IRP" will address the expected load impacts,

either in aggregate for the Time of Use "TOU" rate program, or by individual TOU rate offering. The cost of such analysis is included in the cost of performing the DSM potential study Load Flexibility Analysis task, which the Statement of Work for the potential study identifies as costing \$49,560. However, the TOU analysis is a subset of that task, so not all of the cost may be attributable to TOU. The timing of such analysis is aligned with the 2023 IRP filing.

0141

Please quantify any changes in existing residential load that the company projects to cause by continued operation of the "RESIDENTIAL - SMART SAVER SERVICE" rate schedule, including the timing of such projected changes. a. Please quantify any reduction in revenue requirement by account and by year that is expected to be caused by any changes identified in the first question, above. b. Please specify the amounts in part a that are included in the FAC base Factor and subject to adjustment through the FAC. c. If the estimates described above have not been prepared, please estimate the cost and time of preparing such estimate.

Response:

No such analysis has been performed. The ongoing Demand Side Management Market "DSM" Potential Study, and the Company's 2023 Integrated Resource Plan "IRP" will address the expected load impacts, either in aggregate for the Time of Use "TOU" rate program, or by individual TOU rate offering. The cost of such analysis is included in the cost of performing the DSM potential study Load Flexibility Analysis task, which the Statement of Work for the potential study identifies as costing \$49,560. However, the TOU analysis is a subset of that task, so not all of the cost may be attributable to TOU. The timing of such analysis is aligned with the 2023 IRP filing.

Ameren Missouri's  
Response to MPSC Data Request - MPSC  
ER-2022-0337

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues  
for Electric Service

No.: MPSC 0460

In the “Second Unanimous Stipulation and Agreement” in ER-2021-0240, filed 12/6/2021, Ameren Missouri agreed to the following provision “Rider C: The Company will conduct an engineering review of the Rider C loss rates by December 31, 2022 and will update the Rider C loss rates in its first electric general rate case filed after December 31, 2022 if the engineering review indicates an update of those loss rates is needed.” Please provide the engineering review referenced, and indicate whether Ameren Missouri is of the opinion that the engineering review indicates that an update of the loss rates for Rider C is needed. Information requested by Sarah Lange, ([sarah.lange@psc.mo.gov](mailto:sarah.lange@psc.mo.gov) <<mailto:sarah.lange@psc.mo.gov>>)

**RESPONSE**

**Prepared By: Tom Hickman**  
**Title: Regulatory Rate Consultant**  
**Date: 1/19/2023**

The Company's review took place in two steps with different degrees of review related to Rider C. The first step was an overall review of the Rider C Tariff and its applicability. In this step of review, the Company determined that the justification for Rider C as it applies to customers metered at 34 kV or higher (bullet 2 from the Rider C Tariff) differs from the justification for Rider C as it applies to customers metered at Secondary and on a Primary rate schedule or customers metered at Primary and on a Secondary rate schedule (bullets 1 and 3 from Rider C Tariff).

The justification for bullet 1 and 3 customers is that they are metered at a voltage other than the voltage provided in their rate schedule (which is also at a voltage other than the voltage at which they are delivered power). Generally, a customer is metered at the voltage at which they are delivered power, and to the extent they are not, a metering adjustment is appropriate to account for transformer losses when transformation occurs on the other side of the meter from what is typical for a customer in the same rate class.

The Company performed a second step of review, specifically an engineering review, on the loss rate applicable to these customers. Please see the attached memo, "Rider C Engineering Review Memo", which provides details of the engineering review performed. As a result of the



engineering review, the Company is of the opinion that the current loss factors for Rider C are reasonable and as such is of the opinion that they do not indicate a change is needed. However, the Company reserves the right to further consider its position in line with the timing outlined in the stipulation, requiring a specific decision be made by the first electric general rate case filed after December 31, 2022.

The justification for a discount for bullet 2 Rider C customers is that they are paying a rate designed to recover costs incurred at Primary voltage (despite being served at a greater than primary voltage). The Company is of the opinion that such customer should receive a discount but that a kW and kWh metering reduction **may** not be the most effective or efficient way to reflect this difference in cost to serve between customers served at primary and greater than primary voltages. This determination, however, should be based on analysis conducted relative to the Cost of Service Study and is not a question of the appropriateness of the specific loss factor through an engineering lens. As such, further engineering review was not performed on the rate specific to this provision at this time. The Company plans to further contemplate this question in future rate cases and as a component of a more holistic review of non-residential rates. The Company's opinion is that the loss rates should continue to be applied to these customers until a future point in time when such a holistic review has been completed.

**Topic:** Engineering Review of Low Voltage Distribution Transformer Efficiency Relative to Ameren Missouri's Rider C Loss Factor Adjustment of 0.68%

**Scope:** For low voltage distribution transformers of 15 KV and below, review existing standards, either internal or external, to determine if a detailed analysis is needed, and if so, determine next steps for advancing that analysis.

**Standards Review:**

Internal – Ameren's standard for transformers purchased do not directly specify a minimum efficiency other than the DOE standard. Rather, one evaluation criteria is the lifetime cost analysis of which efficiency is a significant input but other factors are also considered. The DOE standard establishes a minimum efficiency for the industry.

National Standard Evolution – The DOE standard has only changed modestly over time with smaller transformers seeing the minimum increase by slightly less than 1.0% and larger transformers by slightly less than 0.5%. The below chart summarizes the change between the 2010 standard and the 2016 standard. DOE has proposed updates ([DOE Standard Proposed 12/28/2022](#)) that will be working through rulemaking process but are not relevant to a review of transformers currently operating on the Ameren Missouri distribution system.

Comparison of various efficiency standards: NEMA TP-1, NEMA PREMIUM CSL-3 & DOE 2016

The table below lists the minimum efficiencies of low-voltage dry-type three phase distribution transformers required for their kVA rating. The standards for transformers manufactured on or after January 1, 2007 are known as NEMA TP-1 (or Energy Star labeled). On May of 2010 The NEMA CSL-3 standards were introduced with higher efficiency ratings than NEMA TP-1. The benefits of CSL-3 transformers are reduced electrical & heat losses, lower total cost of ownership (TCO), greater energy savings and green/LEED design. These features are beneficial for data centers, healthcare installations, schools & colleges, green applications, LEED buildings and government projects. The CSL-3 efficiency standard was never federally mandated. Transformers manufactured on or after January 1, 2016 are required to meet the minimum DOE 2016 efficiencies listed below. These standards will be federally mandated.

KVA (Three Phase)	NEMA TP-1 (Energy Star) Federally Mandated	NEMA PREMIUM CSL-3* Not Federally Mandated	DOE 2016 Standards Federally Mandated
15 kVA	97.0	97.90	97.89
30 kVA	97.5	98.25	98.23
45 kVA	97.7	98.39	98.40
75 kVA;	98.0	98.60	98.60
112.5 kVA	98.2	98.74	98.74
150 kVA	98.3	98.81	98.83
225 kVA	98.5	98.95	98.94
300 kVA	98.6	99.02	99.02
500 kVA	98.7	99.09	99.14
750 kVA	98.8	99.16	99.23
1000 kVA	98.9	99.23	99.28

[NEMA Standard](#)

**Liquid-Immersed Distribution Transformers**


(2) The efficiency of a liquid-immersed distribution transformer manufactured on or after January 1, 2016, shall be no less than that required for their kVA rating in the table below. Liquid-immersed distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
10	98.70	15	98.65
15	98.82	30	98.83
25	98.95	45	98.92
37.5	99.05	75	99.03
50	99.11	112.5	99.11
75	99.19	150	99.16
100	99.25	225	99.23
167	99.33	300	99.27
250	99.39	500	99.35
333	99.43	750	99.40
500	99.49	1000	99.43
667	99.52	1500	99.48
833	99.55	2000	99.51
		2500	99.53

**Note:** All efficiency values are at 50 percent of nameplate-rated load, determined according to the DOE Test Method for Measuring the Energy Consumption of Distribution Transformers under Appendix A to Subpart K of 10 CFR part 431.

(b) *Liquid-Immersed Distribution Transformers.*

(1) The efficiency of a liquid-immersed distribution transformer manufactured on or after January 1, 2010, but before January 1, 2016, shall be no less than that required for their kVA rating in the table below. Liquid-immersed distribution transformers with kVA ratings not appearing in the table shall have their minimum efficiency level determined by linear interpolation of the kVA and efficiency values immediately above and below that kVA rating.

Expand Table 

Single-phase		Three-phase	
kVA	Efficiency (%)	kVA	Efficiency (%)
10	98.62	15	98.36
15	98.76	30	98.62
25	98.91	45	98.76
37.5	99.01	75	98.91
50	99.08	112.5	99.01
75	99.17	150	99.08
100	99.23	225	99.17
167	99.25	300	99.23
250	99.32	500	99.25
333	99.36	750	99.32
500	99.42	1000	99.36
667	99.46	1500	99.42
833	99.49	2000	99.46
		2500	99.49

Note 3 to paragraph (b)(1): All efficiency values are at 50 percent per-unit load.

### **Summary of Review**

Because the application of Rider C being evaluated is limited to low voltage distribution (not substation class) and because these customers will almost always be 3 phase and almost always be larger than 100 KVA, 3 phase sizes less than 100 KW and 1 phase sizes less than 37.5 KVA were excluded.

It is noted that several factors can have material impacts on the actual operating efficiency of transformers in service including % loading, power factor and load imbalance. However, these are largely impractical or impossible to accurately assess on the basis of an individual installation. Of these factors, transformer loading can materially impact efficiency if the transformer is dramatically oversized (<10% loaded). This is an extreme scenario that is rare. The DOE makes the assumption of 50% average loading (peak load is materially higher) which is reasonable.

Summary of DOE Standard				
3 Phase		1 Phase		
KVA	Efficiency	KVA	Efficiency	
112.5	99.01%	37.5	99.01%	
150	99.08%	50	99.08%	
225	99.17%	75	99.17%	
300	99.23%	100	99.23%	
500	99.25%	167	99.25%	
750	99.32%	250	99.32%	
1000	99.36%	333	99.36%	
1500	99.42%	500	99.42%	
2000	99.46%	667	99.46%	
2500	99.49%	833	99.49%	
Average	99.28%	Average	99.28%	
loss factor	0.72%	loss factor	0.72%	

**Conclusion:** Ameren Missouri's Rider C loss factor adjustment of 0.68% appears reasonable for the purpose it was intended. Based on the limited number of applications where a loss adjustment factor is required, for low voltage transformer applications, the 0.68% loss factor is consistent with existing DOE and ANSI standards.