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Sarah L. K. Lange
Rebuttal Testimony
File No. ER-2022-0337

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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

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d/b/a AMEREN MISSOURI

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REBUTTAL TESTIMONY OF

SARAH L.K. LANGE

UNION ELECTRIC COMPANY,
d/b/a AMEREN MISSOURI

CASE NO. ER-2022-0337

EXECUTIVE SUMMARY

Q. Please state your name and business address.

A. My name is Sarah L.K. Lange, and my business address is 200 Madison Street, Jefferson City, MO 65102.

Q. Are you the same Sarah L.K. Lange who provided direct class cost of service (CCoS) and rate design testimony in this matter, filed January 24, 2023?

A. Yes.

Q. What areas will you be addressing in this testimony?

A. I explain why the tracker request as described in the direct testimony of Steven M. Wills on behalf of Ameren Missouri should not be granted. I will be addressing the CCoS Study results presented by Ameren witness Thomas Hickman, and the discussion of those results provided by Steve W. Chriss on behalf of Midwest Energy Consumers Group (MECG) and Maurice Brubaker on behalf of Missouri Industrial Energy Consumers (MIEC). In particular, I describe how the distribution classification method selection choice significantly undermines the reliability of the study. I will also respond to Michael W. Harding (Ameren Missouri), Thomas Hickman, Steve W. Chriss, Maurice Brubaker, and Jacqueline A. Hutchinson (Consumers Council of Missouri) concerning class-level revenue requirements and rate design.

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

A. Yes.

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

MISCELLANEOUS RATE STRUCTURE AND RATE DESIGN

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

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

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

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

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

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

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

	Residential	SGS	LGS	SPS	LPS	Lighting	Total
Treatment:	Equal	Equal	Above	Above+	Above+	Hold	Revenue Requirement Allocated
Step 1	$ -	$ -	$ -	$ 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%	
Step 2	$ -	$ -	$ 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%	
Step 3	$ 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%	
Overall Recommended Increase $:	$ 74,240,792	$ 16,406,002	$ 51,141,591	$ 30,903,324	$ 26,564,515	$ -	$ 199,256,223
Overall Recommended Increase %:	5.41%	5.41%	9.16%	12.91%	12.91%	0.00%	7.32%

Q. Mr. Harding addresses several miscellaneous tariff items, for those for which you are responsible, what is your recommendation?

A. Staff's positions are provided below:

1. 6(M) E&M Lighting updates, Sheet No. 59 – Staff does not oppose;
2. Removal of Unmetered Customer Charge from 2(M) Optional TOU rate, 19 Sheet No. 55 – Staff does not oppose;
3. Sheet No. 110: Eliminates outdated language in Section J., Non-Standard Service, specifically:

   > 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.

   – Staff does not oppose;
4. Sheet No. 115: Correction to Section reference, Overhead Extensions To Residential Subdivisions in Section 1.a. – Staff does not oppose;
5. Sheet No. 123: Correction to Special Facilities reference in Section 2 – Staff does not oppose;
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;
7. Sheet No. 137: Correction to Rent Inclusion section number reference – Staff does not oppose;
8. Sheet No. 138: Correction to Missouri Code of State Regulations reference in Partial Payments Section – Staff does not oppose;

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

AMEREN MISSOURI'S REQUEST TO COLLECT CURRENT CUSTOMER BILL SAVINGS FROM FUTURE CUSTOMERS

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

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

Q. Does Staff recommend granting the tracking authority requested?

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

The Tracking Authority Requested is Unreasonable

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

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

A. Mr. Wills testifies at page 19 that the TOU rate plans "can provide significant benefits to those customers in the form of lower bills, achieved in a manner that can also provide system benefits for all customers arising from the shifting of usage away from periods of high demand, and therefore higher cost, on the system. The Commission has expressed a public policy interest in advancing TOU rates in recent years in several contexts." In other words, Mr. Wills envisions three benefit categories:

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

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

A. No.

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

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

Specifically, Ameren Missouri not only responded that it had not identified potential early retirement of distribution and substation infrastructure, transmission and substation infrastructure, or generation infrastructure due to successful implementation of opt-in time-based rate schedules occurs, but Ameren Missouri's responses to each of these questions included the statement that "***nor is it clear to the Company why implementation of TOU rates would be expected to result in the retirement of infrastructure***." ***[Emphasis added.]*** Finally, the Ameren Missouri response indicated "***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.***" ***[Emphasis added.]***

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

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

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

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

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

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

Q. Why?

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

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

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

A. Yes. At page 8 of his Direct Testimony, Mr. Wills testifies that for customers electing to take service on the Overnight Savers, Smart Savers, and Ultimate Savers rate plans "around 80% of customer outcomes and individual bills are lower than they would be on the legacy Anytime User rate plan." However, where rates have been designed to induce changes in customer load but without any analysis of the load to be changed, the benefits to be adduced, or the costs to be mitigated or avoided, there is no grounds for an assumption the resulting bills are closer to cost of service.

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

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

A. No.

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

A. No.

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

A. Shifting of energy consumption away from periods of high energy prices or increasing usage in periods of low energy prices will result in a reduction to net fuel costs. By operation of the Fuel Adjustment Clause (FAC), and without need for a tracker, shareholders will retain 5% of the value of this benefit, and 95% of the value of the benefit will be passed to all ratepayers on the basis of energy consumption through the FAC.

The Requested Calculation of the Tracker is Unreasonable

Q. At page 17 Mr. Wills states:

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

Is this calculation reasonable?

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

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

Q. What do you mean by effective energy storage?

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

As another example, if I want to minimize my use of my air conditioner between 3 and 7 pm, one way to achieve that is to cool my house down to 62 degrees by 2:59. Then, I may set my thermostat to 82 degrees from 3-7, and lower it back to 72 degrees at 7:01. It is likely that I will have consumed more energy than if I had kept my thermostat at 72 the entire time.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Alternative to Tracker

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

A. Yes. The first way to address this problem would be to redesign these rate plans so that the differentials in the rate plans correspond to the variations in the cost of providing service in selected time periods. The second way to address this problem would be to increase the Overnight Savers, Smart Savers, and Ultimate Savers rates so that customers who have opted into the plans provide the same average revenue per kWh as those who have not opted into the plans, based on the billing determinants associated with each rate plan.

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

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

UPDATE ON RIDER C ENGINEERING REVIEW

Q. What was Staff's direct- recommended treatment of Rider C adjustments?[1]

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

[1] 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.

Q. In the "Second Unanimous Stipulation and Agreement" filed 12/6/2021, in ER-2021-0240, Ameren Missouri agreed to "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." Has Ameren Missouri conducted this engineering review?

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

"RIDER B STUDY"

Q. What is Rider B?

A. Rider B provides:

> DISCOUNTS APPLICABLE FOR SERVICE TO SUBSTATIONS OWNED BY CUSTOMER IN LIEU OF COMPANY OWNERSHIP
> Where a customer served under rate schedules 4(M) or 11 (M) takes delivery of power and energy at a delivery voltage of 34kV or higher, Company will allow discounts from its applicable rate schedule as follows:
> *1. A monthly credit of $1.24/kW of billing demand for customers taking service at 34.5 or 69kV.
> *2. A monthly credit of $1.47/kW of billing demand for customers taking service at 115kV or higher.

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

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

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

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

A. No.

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

A. Mr. Hickman describes the following calculation:

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

Mr. Hickman then testifies that "The calculated result from the study should most closely match the 115 kV and above rate, as those customers do not utilize any substations in the 362 account, whereas customers served at 34.5 or 69 kV would utilize a subset of those substations but not all of them – and far less than customers served at standard primary or secondary voltages. Although the calculated discount of $1.34 per kW is slightly different from the $1.47 per kW discount currently being given to those customers, because the Company is recommending equal percentage increases for all customer classes, the Company recommends making an equal percentage adjustment to Rider B consistent with all customer classes."

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

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

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

A. No.

Q. How would such a review be conducted?

A. The first step would be to gather factual data concerning the infrastructure and/or the cost of the infrastructure that operates as customer-specific infrastructure for the relevant customers. Data could be gathered for either all relevant customers or a subset of relevant customers that constitutes a reasonable sample.

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

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

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

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

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

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

The alternative path to obtaining this information is:

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

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

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

CCOS STUDY RESULTS AND INTERCLASS REVENUE SHIFTS

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

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

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

Could you explain the misconceptions that underlie these discussions?

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

For example, right now Ameren Missouri has a solar Certificate of Convenience and Necessity ("CCN") filing to install production capacity to meet "an energy need." Under Mr. Chriss' definition and consistent with the Ameren Missouri CCoS Study on which he relies, this solar capacity would be considered a demand cost. If Coincident Peak ("CP") capacity were truly the only consideration in generation selection with or without market participation, all capacity needs would be met with a capacitor.[2]

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

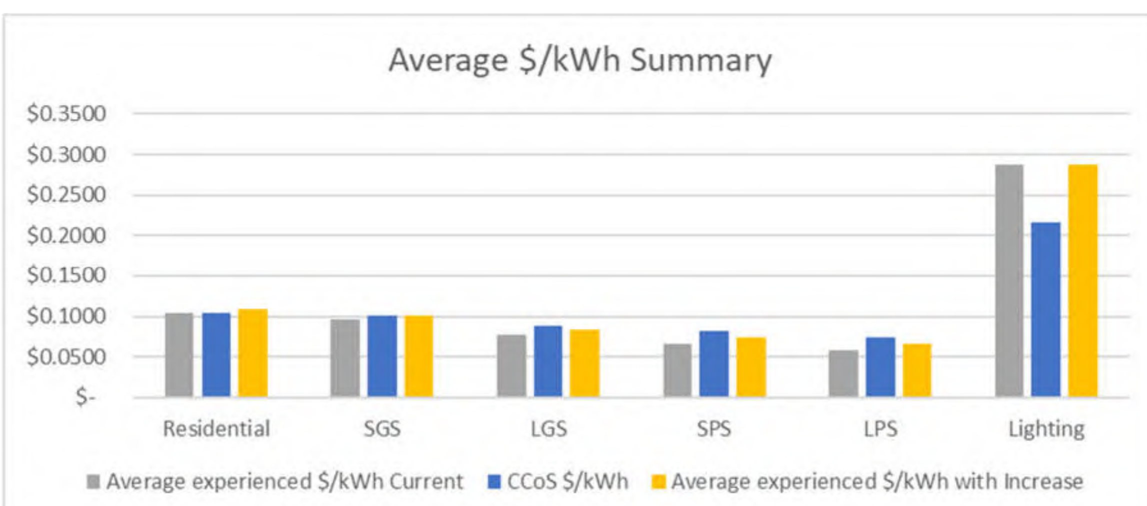
[2] Coincident Peak refers to the highest interval of energy usage across multiple customer groups.

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

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

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

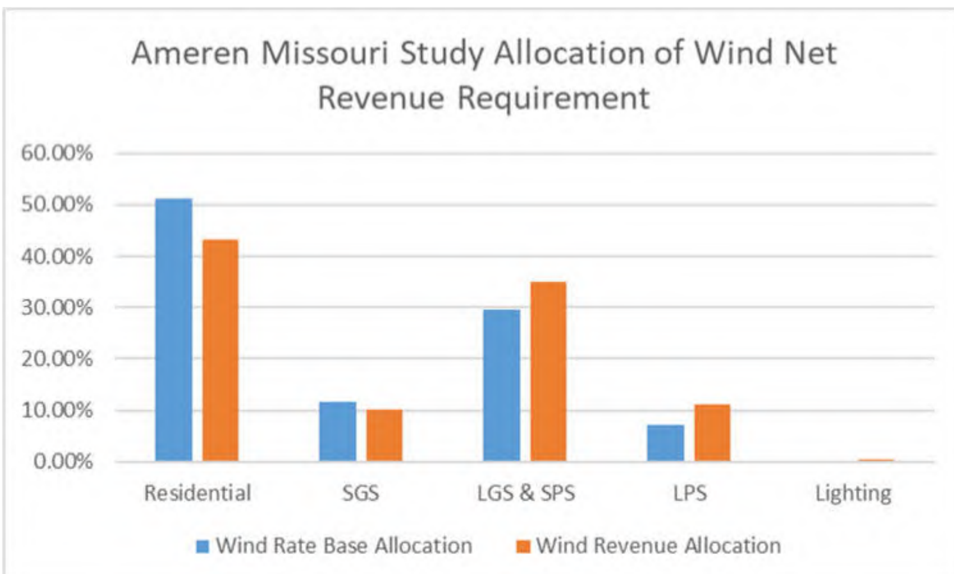
A. No. These recommendations are based on the unreasonable Ameren Missouri study, with minor revisions in the case of Mr. Chriss. These recommendations are inconsistent with my more reasonable study results and my recommended interclass revenue responsibility recommendations, summarized below:



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:

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

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

Q. Please summarize the conclusions of your direct testimony.

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

II. THE NEED FOR RENEWABLE RESOURCES

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

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

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

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

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

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

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

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

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

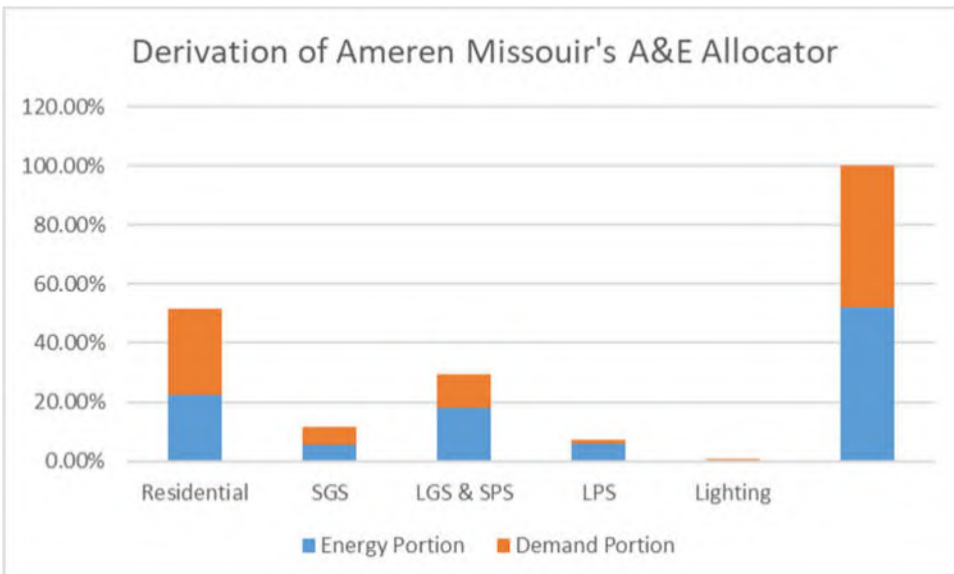
A. Yes. Mr. Hickman uses a 4NCP A&E allocator for all production plant costs and certain expenses, and the loss-weighted energy allocator for remaining production expenses and for revenues from energy sales. Mr. Brubaker relies upon this production cost allocation for his derivative CCoS study, and expands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

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

> Q. IS THE COLLECTION OF DEMAND-RELATED COSTS THROUGH AN ENERGY CHARGE CONSISTENT WITH THE COMPANY'S CLASSIFICATION AND ALLOCATION OF DEMAND-RELATED COSTS?
>
> A. No. In its class cost of service study, the Company does not classify or allocate any of its demand-related costs on an energy basis. Rather, these costs are incurred, and therefore classified, based on customer demand or number of customers. Costs should be collected in a manner which reflects how they are incurred. As such, collecting demand-related (fixed) costs through an energy (variable) charge violates cost causation principles.

[3] Brubaker direct, page 3.

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



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

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

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

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

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

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

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

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

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

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

	2:00	3:00	4:00	5:00	6:00	Max
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
LGS & SPS	**640**	**640**	**650**	**640**	**640**	650

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:

	True NCP	True NCP with Classes Summed	Combined NCP	Difference
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%

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

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:

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

Then, I inserted this calculation into Mr. Hickman's production allocator worksheet, resulting in the differences in allocation reflected below:

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

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

A. Yes, definitely. Ameren Missouri directly allocated $6.4 billion of net rate base with this allocator, as well as $701 million in direct expense allocation. The direct allocated revenue requirement is $1,161,637,094, with significant indirect allocation following this allocation, including pension and labor expense, property taxes, and PISA allocations.

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

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

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?

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

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

Transmission Revenue Requirement and Rate Base

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

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

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

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.

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

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

Q. What does a StatCom do?

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

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

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

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

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

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

A. Reactive power is required in excess of apparent power in devices that induce magnetic fields, such as pumps and motors. Common appliances that require disproportionate reactive power include heat pumps, refrigeration equipment, and motors (including fans). Examples of end uses that typically do not draw disproportionate reactive power include heating elements such as those found in dryers or electric ranges, and electronics (excluding cooling components). Note, the transmission and distribution systems themselves operate in a manner that requires or provides reactive power, particularly in operation of transformers, and in the performance of the system in very high and very low loading positions.

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

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

Distribution Revenue Requirement

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

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

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

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

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

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

Q. In what ways was Ameren Missouri's distribution classification and allocations inconsistent with the NARUC Manual or otherwise unreasonable?[4]

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

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

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

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[4] 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.

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

At page 95 of the NARUC Manual:

> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.
>
> When allocating distribution costs determined by the minimum-size method, some cost analysists will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

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

> The minimum grid approach re-designs the distribution system to determine the cost in current year dollars of a **hypothetical system that would serve all customers with voltage but not power (or with minimum demand of 0.5 KW)**, yet still satisfy the minimum standards for pole height and efficient conductor and transformer size. The calculations can be based either on the system as a whole or on a sample of areas reflecting different geographical, service and customer density characteristics.
>
> When applying this approach, it is necessary to **take care that the minimum size equipment being analyzed is, in fact, the minimum-sized equipment available, and not merely the minimum the minimum size stocked by the company or usually installed by the company**. **To the degree that the equipment being costed is larger than a true minimum, the minimum grid calculation will include costs more properly allocated to demand**. **[Emphasis added.]**

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

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

Q. Please described Ameren Missouri's "minimum" distribution system, as studied by Mr. Hickman.

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

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

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

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

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

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

---

[5] "A.F. Vandas" tab of Hickman CCoS Study workpaper.

[6] Workpaper "MPSC 0635 – 2009 Study COSS Distribution Accounts.xls," and "Summary" tab of "2022 Minimum Size Study Final" workpaper.

> - Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. **Balance of plant account is demand component.** (Note: two conductors in minimum system.)
>
> 3. Accounts 366 and 367 – Underground Conduits, Conductors, and Devices
>
> - Determine minimum size cable currently being installed.
>
> - Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, based on ratio of cable account.
>
> - Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. **Balance of plant account is demand component.**
> **[Emphasis added.]**

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

> 2. Account 365 – Overhead Conductors and Devices
>
> - **If accounts are divided between primary and secondary voltages**, develop a customer component separately for each. The total investment assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.
>
> - **When developing the customer component, consider only the investment in conductors, and not in devices such as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component,** based on the conductor assignment.
>
> > - Determine the feet, investment and average installed book cost per foot for distribution conductors by size and type.
> >
> > - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.
> >
> > - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)

- Balance of conductor investment is assigned to demand.

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

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

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

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

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

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

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

- Balance of cable investment is assigned to demand.

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

While there is discussion of the classification of devices in Account 365 pursuant to the minimum intercept method, under the discussion of Account 365 classification using the minimum size method, there is the simple and clear statement that "Balance of plant account is demand component," unequivocally stating that all devices in Account 365 are classified as demand-related. This is in contrast to the decision of Ameren Missouri to classify $594,445,713 of plant related to lightening arrestors, switches, and reclosers, as "customer-related".[7]

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

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

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

> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. **When using this distribution method, the analyst must be aware that the minimum size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.**
>
> When allocating distribution costs determined by the minimum-size method, some cost analysis will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as

[7] 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.

> demand-related. Then those **customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs**.
>
> Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus the customer cost of a particular piece of equipment has no demand cost in it whatsoever. **[Emphasis added.]**

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

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

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

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

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

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

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

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

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

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

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

A. No.

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

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

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

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

Adjustments to Ameren Missouri Customer Classification

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

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

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

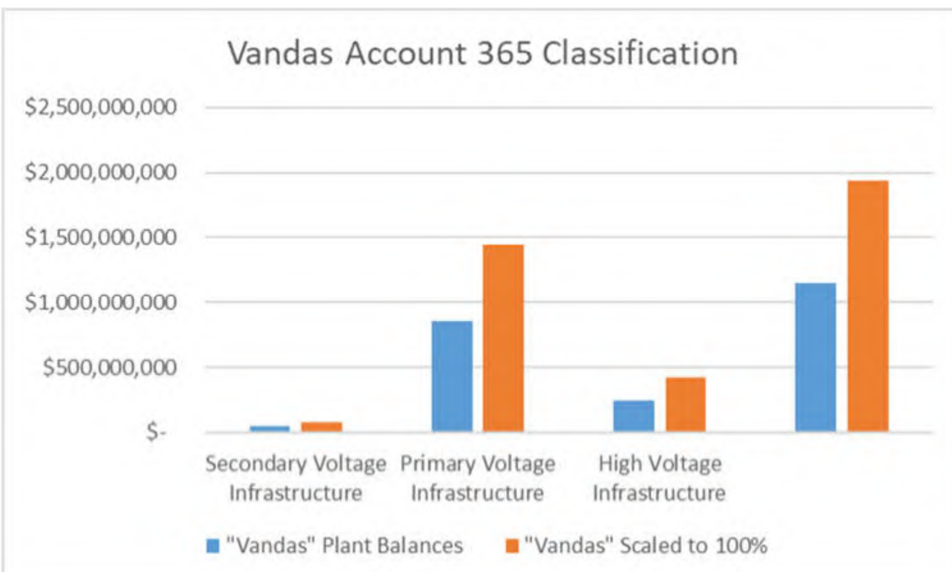
A. No.

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

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

VANDAS STUDY RESULTS								
						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

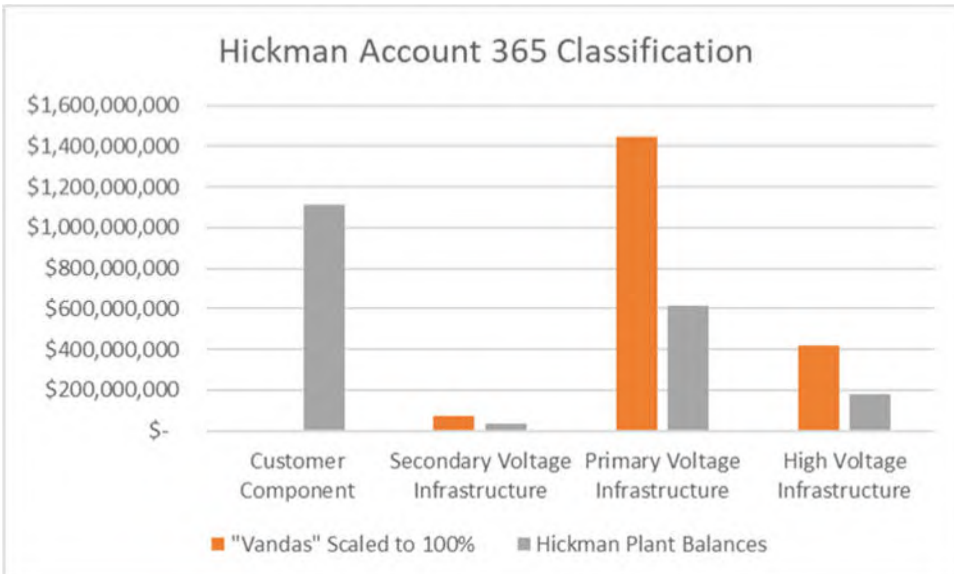
By multiplying the "Vandas" Account 365 classifiers with the Account 365 balance, we derive the following values of plant for each type of infrastructure, both using the provided raw values quoted above, and after scaling these classifiers to allocate 100% of the plant balance:



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:

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.[8]

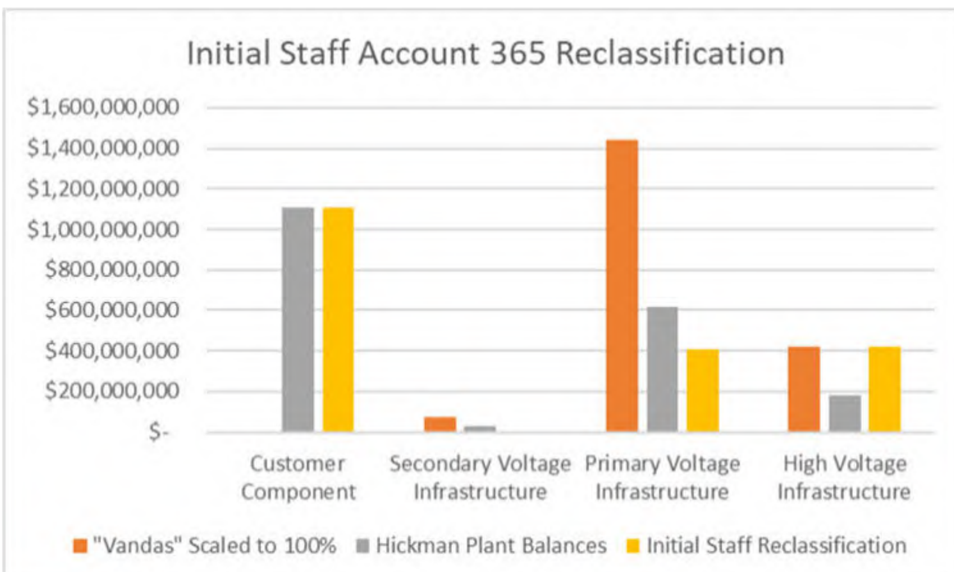
[8] Because Mr. Hickman ignored secondary-voltage infrastructure in Accounts 364-367 to the extent such infrastructure is present in his performance of his minimum-size study, it is reasonable to progressively net the minimum-system value against first secondary, then primary, then high voltage infrastructure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

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

A. A table providing all reclassified balances using Mr. Hickman's customer 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	$ -	$ -	$ -	$ -

A comparison of the initial Staff reclassification and the "Vandas" and Hickman classifications is provided below:



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

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

	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%

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

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

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

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

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

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

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

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

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

	Residential	SGS	LGS	SPS	LPS Primary	LPS Sub	LPS Trans
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

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

	Residential	SGS	LGS	SPS	LPS Primary	LPS Sub	LPS Trans
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

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

	LPS Primary	LPS Sub	LPS Trans	LPS Aggregate
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

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

	LGS	SPS	LGS/SPS
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

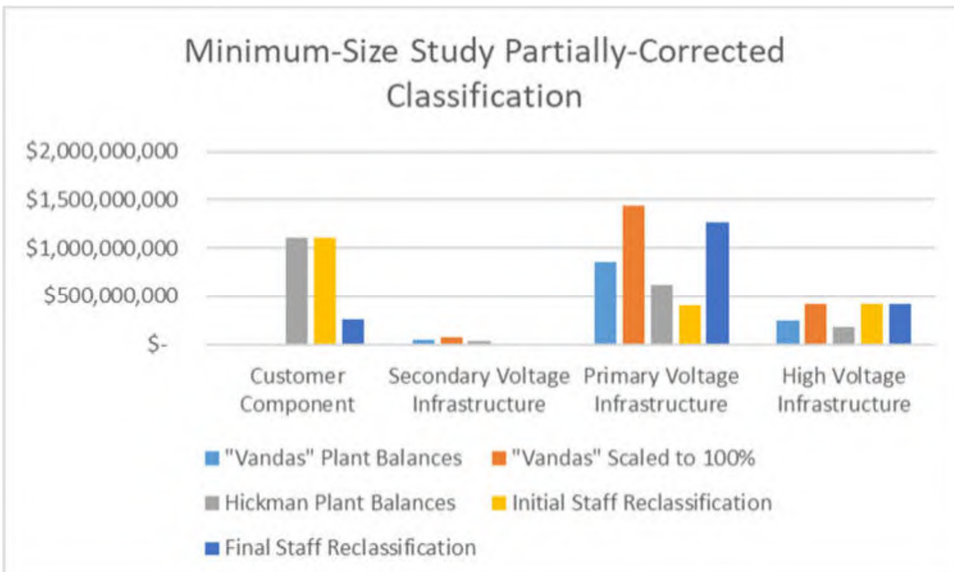
Q. What effect does the correction of the customer allocator to a weighted customer allocator for the distribution accounts have on the level of rate base directly allocated to each customer class in the Ameren Missouri study?

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

	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%
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%

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

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



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

A. Addressing these errors as described above results in the shifts in allocated rate base provided below, and the shifts in return on rate base using the Ameren Missouri study 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)

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

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

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

	RESIDENTIAL	SGS	LGS & SPS	LPS	LIGHTING
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)

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

A. No. Ameren Missouri's study remains unacceptably deficient due to the failure to address customer-specific infrastructure that is recorded in Accounts 364-368, and due to the general inapplicability of the minimum-size approach to a primary-based system. Further, the minimum-size approach predates the modern "smart grid" which is more appropriately allocated using the weighted hour method provided in the Staff study, which is also more compatible with rate structure modernization.

Combined Adjustments to Ameren Missouri Study

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

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

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

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

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

A. As is, these results suggest that it would be reasonable to hold the lighting class revenue requirement constant, and to apply an equal percent increase to the revenue requirements of all other classes.[9]

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

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

RESIDENTIAL RATE DESIGN

Residential Customer Charges

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

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

[9] 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.

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

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

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

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

A. In short, no. Staff relies on the basic customer method of cost causation, which holds that the customer charge should include (1) the costs and expenses of metering and billing customers, (2) the cost of the infrastructure that varies with the number of customers served, including related income taxes, and (3) the proportionate labor, non-labor, and distribution expense associated with the infrastructure. In this case for its calculation, Staff also included additional customer service expenses, and also included approximately $11.9 million of the functionalized "Other/General" revenue requirement out of an abundance of caution. However, Ameren Missouri exceeds this allocation in two main ways. First, Ameren Missouri includes as "customer-related" its entire minimum-size distribution costs and expense calculation, and second, the Ameren Missouri minimum-size distribution calculation is poorly calculated. In other words, Ameren Missouri errs in making the decision to include this category of revenue requirement, but even if it were reasonable to include it, Ameren Missouri's calculation is wrong.[10]

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

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

Ultimate Saver and Smart Saver Discounted Customer Charges

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

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

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

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

[10] 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."

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

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

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

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

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

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

Opt-in ToU Rate Plans

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

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

Q. At page 20 Mr. Wills testifies about,

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

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

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

A. No.

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

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

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

A. No.

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

A. No.

Default Time of Use Rate Plan

Q. At page 13 Ms. Hutchinson testifies "Ameren Missouri should no longer be allowed to automatically place consumers on a rate plan, unless a consumer opts out of that plan ("Opting- Out"), i.e., with regard to time-of-use utility rates. While Consumers Council is not opposed to time of use utility rates, and thinks they are a useful tool to help achieve energy efficiency, we recommend that consumers not be switched to any new rate plan without affirmatively consenting to the switch ("Opting-In")."

Do you agree?

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

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

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

> Ameren is currently offering a variety of new rate options to customers, and Consumers Council is pleased that consumers have such options, as different rate plans could result in substantial savings, if they fit a particular customer's lifestyle. However, Consumers Council is concerned that the policy of switching electric consumers to "Opt-Out" plans should not be permitted in the future. Consumers should ideally never be switched to another rate plan without giving their clear affirmative consent.
>
> Based on an agreement in the previous rate case, Ameren Missouri will automatically switch a customer to an "Evening/Morning" time-of-use plan. Sometimes, despite the efforts to educate the consumer, the switch is made without the consumer realizing what has happened. The decision of rate plans has the potential to add additional costs, creates vulnerability for families with small children, working individuals who do not take time to read the inserts, those living with disabilities, and seniors.
>
> It is Consumers Council's recommendation that Ameren Missouri should continue to educate customers about the various rate plans, but should also require customers to affirm their desire to participate by "Opting-In" before a switch in rate plans is allowed.
>
> A letter to the Public Service Commission was shared with Consumers Council. (Attachment 3 to this testimony). The letter is from an Ameren

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

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

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

NON-RESIDENTIAL RATE DESIGN

LGS & SPS Rate Design

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

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

Do you agree?

A. No. Mr. Chriss's recommendations are based on the unreliable Ameren Missouri study. Even if the study were reliable, Mr. Chriss's recommended shifts assume an unreasonable level of precision and accuracy in the results for any CCoS. Finally, Mr. Chriss's intraclass discussion is fundamentally inaccurate, and again, based on the unreliable Ameren Missouri study.

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

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

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

[11] 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.

Special Rate Structures for EV Charging

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

> [T]he Commission should require Ameren to create alternative optional LGS ("LGS-EV") and SP ("SP-EV") rates for EV charging customers with load sizes that would qualify to take service on LGS or SP rates. These alternatives could then serve as a basis from which the Company and stakeholders can design durable EV charging rate schedules in the rate redesign process….
>
> …For the purposes of this docket, MECG proposes to reallocate the summer demand charge revenue requirement to the first block of the summer energy rate and reallocate the winter demand charge revenue requirement to the first block of the winter energy rate. This reallocation would serve two purposes: first, it would reduce the barrier to entry for very low usage EV chargers versus LGS and SP's demand charges; and second, it would recover the demand charge revenue requirements in the low load factor first blocks (up to 20.8 percent monthly load factor), which would provide more meaningful fixed cost recovery than spreading demand charge revenue across the three energy blocks.

Should the proposed rate schedules be created?

A. No.

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

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

Q. Is this proposal cost-based?

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

Q. Is it likely that any customer with a high demand and low load factor, such as welding shops, smelters, grain dryers, millers and other customers currently served on the LGS, SPS, and LPS rate schedules would prefer to avoid the demand charges that Mr. Chriss references?

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

LPS Rate Design

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

A. Mr. Brubaker on behalf of MIEC recommends that all of the charges, except for the Low-Income Pilot Program Charge, should receive the same percentage increase.[12]

Q. Do you agree with this recommendation?

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

[12] Brubaker Direct page 4.

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

CONCLUSION

Q. Does this conclude your rebuttal testimony?

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

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 10th 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

D Suzie Mankin

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>)

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 o.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.

DOE Transformer Testing Standard 10 CFR part 431 Subpart K

(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.