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.	)))	File No. ER-2022-0337

AMEREN MISSOURI'S REPLY BRIEF

COMES NOW Union Electric d/b/a Ameren Missouri ("Ameren Missouri" or "the Company"), by and through counsel, and hereby files its Reply Brief.

Introduction

The following parties filed Initial Briefs in this case: Ameren Missouri,[1] Missouri Public Service Commission ("Commission") Staff ("Staff"),[2] Renew Missouri Advocates d/b/a Renew Missouri ("Renew"),[3] the Office of Public Counsel ("OPC"),[4] Midwest Energy Consumers Group ("MECG"),[5] Missouri Industrial Energy Consumers ("MIEC"),[6] the Sierra Club,[7] the Missouri State Conference of the National Association for the Advancement of Colored People ("NAACP"), and Metropolitan Congregations United ("MCU").[8] Ameren Missouri appreciates the opportunity to reply to the Initial Briefs filed by other parties. Ameren Missouri will avoid regurgitation of arguments made in its Initial Brief, and will focus this Reply Brief on correcting misstatements by other parties and countering certain arguments presented in other parties' Initial Briefs.

[1] File No. ER-2022-0337, EFIS Item No. 441, Ameren Missouri's Initial Post-Hearing Brief.
[2] EFIS Item No. 443, Staff's Initial Brief.
[3] EFIS Item No. 442, Renew Missouri's Initial Post-Hearing Brief.
[4] EFIS Item No. 440, Public Counsel's Initial Brief.
[5] EFIS Item No. 444, MECG's Initial Brief.
[6] EFIS Item No. 445, MIEC's Initial Post-Hearing Brief.
[7] EFIS Item No. 446, Sierra Club's Initial Post-Hearing Brief, & EFIS No. 447, Sierra Club's Motion for Leave to Late File Initial Post-Hearing Brief.
[8] EFIS Item No. 439, NAACP & MCU filed a Consolidated Post-Hearing Brief.

I. **<u>Reply to Staff's Initial Brief</u>**

A. Class Cost of Service Study ("CCOSS")

1. <u>Sub-issue 1A. Production Cost Allocation</u>

For the reasons laid out in Ameren Missouri's Initial Brief, production costs should be allocated among the customer classes as set out in the Company's CCOSS.[9] Staff's novel allocation of production sales and purchases presents another reason to reject Staff's proposed production allocations. Staff criticizes the Company's allocation of off-system sales revenue on the basis of class energy, stating that "[i]t is not 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."[10] Allocation of off-system sales revenue in a CCOSS is certainly a complex topic, and selection of the most appropriate allocation method for off-system sales definitely has room for differences of opinion. However, contrasting the Company's allocation, which Staff considers unreasonable, with the Staff's alternative approach that is counter to regulatory principles and results in utterly nonsensical potential results, demonstrates that the Company's allocation of off-system sales revenue is far superior to Staff's approach.

For example, the record shows that Staff's allocation of production sales and purchases is based on an hourly analysis of the value of energy consumed by each class versus the value of energy generated by the assets allocated to each class.[11] As MIEC witness Maurice Brubaker showed in rebuttal testimony, Staff is effectively treating the Residential and SGS classes as "sales for resale" classes so that once the cost of a plant is allocated to the Residential or SGS classes, those two classes can now essentially "sell" energy to other classes (LGS, SPS, and LPS) at market energy prices,

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[9] EFIS Item No. 441, Ameren Missouri's Initial Post-Hearing Brief, pp. 8 – 10.
[10] EFIS Item No. 443, Staff's Initial Brief, p. 20.
[11] <u>Id</u>., p. 22, under Step 4.

which is wholly illogical.[12] Under Mr. Brubaker's calculation of Staff's allocation of production revenues, the Residential class received a credit of $194 million, and the SGS class received a credit of $39 million, which far exceeds the total credit of $55 million embedded in the revenue requirement – meaning the other classes are receiving a charge in order to fund the larger credit for the two small classes.[13] Thus, rather than LGS, SPS, and LPS customers benefitting from the energy at the embedded cost associated with assets developed by the Company to serve all customers, they are purchasing energy from the Residential and SGS classes to the tune of at least $178 million.[14] This concept is totally counter to the concept of regulated utility infrastructure that is developed to meet the needs of the totality of the retail load served by a utility, which is provided to customers at its embedded cost protecting its customers from exposure to volatile energy markets.

Under Staff's view of off-system sales, rate classes can essentially become merchant generators to sell energy to other regulated rate classes. And any class on the "buy-side" of this market-priced transaction is totally exposed to market prices rather than realizing the benefit of regulation that is supposed to be based on the concept of service at the cost of providing that service. Staff's approach is simply not an improvement in allocation over the Company's method, and is not a reasonable approach at all.

Staff's illogical transformation of the Residential and SGS classes into "sales for resale" classes is just another illustration of Staff's unreasonable methodology to significantly shift revenue responsibility to the LGS, SPS, and LPS classes. In the Company's Initial Brief, the Company explained: "Staff is so desperate to significantly shift revenue responsibility to the LGS, SPS and LPS classes, and away from the small (Residential and SGS) customers, that Staff will concoct a

[12] Exhibit 351, Rebuttal Testimony of Maurice Brubaker, pp. 6 – 8.
[13] Id., p. 7, Table.
[14] Id. Assuming some portion of the $55 million overall credit included in the revenue requirement might be assigned to the larger customers classes, here is the math: $194 million + $39 million - $55 million = $178 million.

CCOSS that they now claim they lacked the data to perform, and recommend shifting revenue responsibility significantly thereon."[15] Yet again, Staff seems intent on finding ways to shift costs and revenue responsibility away from Residential and SGS customers, even transforming them into merchant generators — acting like LGS, SPS, and LPS customers have been transformed from retail customers buying electricity from the Company into direct wholesale market participants buying electricity from the market.

It is no wonder then that Company witness Thomas Hickman shows Staff's intended effect if followed through: Residential customers' rates would be 23% below national averages and Industrial customers' rates would be 14% above national averages if Staff's CCOSS were followed.[16] Staff's Initial Brief challenges the Company's national rate comparison analysis using information from the Edison Electric Institute ("EEI") demonstrating that following the results of the Staff's CCOSS would make Ameren Missouri's rates extreme outliers relative to our peer utilities across the nation through misunderstandings and mischaracterizations of the Company's analysis.[17] The following four facts and two resulting observations from the record in this case show Staff's study unambiguously results in rates so extremely out of line with national averages that it should be a major red flag about the biases and lack of cost basis in Staff's study:

- Fact 1 – The EEI's most recent rate comparison report indicates that the Company's Industrial rates are currently 8% below the national average.[18]

[15] EFIS Item No. 441, Ameren Missouri's Initial Post-Hearing Brief, p. 21.
[16] Exhibit 37, Surrebuttal Testimony of Thomas Hickman, p. 5 & Table TH-1.
[17] EFIS Item No. 443, Staff's Initial Brief, pp. 50 – 53.
[18] Exhibit 36, Rebuttal Testimony of Thomas Hickman, p. 3, Table TH-1.

- Fact 2 – According to Staff's CCOSS results, the two rate classes with the overwhelming majority of Industrial load — the LPS and SPS classes — would need to increase by 27.12% and 24.14%, respectively, to match Staff's cost of service.[19]
- Observation 1 – No math can be applied to Fact 1 and Fact 2 above that does not result in Industrial rates based on Staff's CCOSS that are not at least 10% above the national average. Increasing rates that are less than 10% below the national average by more than 20% necessarily results in rates more than 10% above the national average.
- Fact 3 – The EEI's most recent rate comparison report indicates that the Company's Residential rates are currently 23% below the national average.[20]
- Fact 4 – Under Staff's CCOSS results, the Residential class rates would need to increase by less than 1% to match Staff's cost of service.[21]
- Observation 2 – There is no math you can apply to Fact 3 and Fact 4 above that does not result in Residential rates based on Staff's CCOSS that are not at least 20% below the national average. Increasing rates that are more than 20% below the national average by less than 1% necessarily results in rates more than 20% below the national average.

Therefore, Staff's study unambiguously results in rates that are so out of line with national averages that it should be a major red flag about the biases and lack of cost basis in Staff's study.

To appreciate how Staff misunderstands and mischaracterizes the Company's analysis on a more granular level, it is important to start with a threshold understanding of how the Company used the EEI benchmarking data in its analysis. The EEI report provides for a baseline understanding of how the Company's rates compare to national averages, based on a common historical period and

[19] Exhibit 136, Direct Testimony of Sarah L.K. Lange, p. 25, Table, bottom row under LPS and SPS columns.
[20] Exhibit 36, Rebuttal Testimony of Thomas Hickman, p. 3, Table TH-1.
[21] Exhibit 136, Direct Testimony of Sarah L.K. Lange, p. 25, Table, bottom row under Residential column.

methodology. Said another way, to compare the Company's rates to the EEI average, the Company rates reflected in the comparison have to be based on the same time period as the EEI's national average analysis, and calculated in the same manner as the EEI instructs utilities to calculate rates for inclusion in the national averages in its report. The starting point of the analysis is exactly that – an apples-to-apples comparison of Ameren Missouri's rates by class as reported to EEI for their analysis to the resultant national average rates by class from EEI's analysis (e.g., Ameren Missouri's Industrial rates are 8% below the national average).[22]

The Ameren Missouri rates that underlie that historical benchmarking are, as should be obvious, based on rates that existed prior to this case (and still exist until a final order in this case). So, in order to compare Ameren Missouri's rates, as they would look after this case based on adoption of Staff's CCOSS, to the national averages from the time period used to conduct the EEI national average analysis, it is necessary to apply the rate increase implied in this case that would arise from application of the results of Staff's CCOSS to the historical Company rates from the EEI analysis, which are otherwise calculated in a manner that is consistent for purposes of comparison with the national rates in the EEI report. This approach keeps all elements of the comparison consistent with the EEI benchmarking data, but in effect, asks the question, "what would this analysis have shown if, during the period used to benchmark Ameren Missouri's rates against the national average, Ameren Missouri's rates were higher by the exact amount of rate increase suggested by Staff's CCOS study?" To that end, the Company calculated the percentage increase in Residential and Industrial rates that would arise from application of Staff's CCOSS results.[23]

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[22] Exhibit 36, Rebuttal Testimony of Thomas Hickman, p. 3, Table TH-1.
[23] Exhibit 37, Surrebuttal Testimony of Thomas Hickman, p. 5, Table TH-1, & Hickman SR WRKPRS - Table TH-1 Workpaper.

To do that, it was necessary to take a weighted average of the implied rate increase from Staff's CCOSS for each Non-Residential class, weighted by the proportion of the Industrial load that is included in that class, to determine the overall implied increase for Industrial customers. Using information about how much of the Company's Industrial load is within each rate class (as presented both in Company witness Thomas Hickman's workpapers and in Exhibit 179 that Staff introduced into the record), it was simple math to determine the weighted average increase that would apply to Industrial load if each of Staff's implied rate class increases were implemented. Then, the Company simply increased the baseline historical rates in the original EEI report by the resultant weighted average percentage increase in rates applicable to Industrial load in order to answer the question of how that historical benchmarking would have looked if the underlying rates at the time had been higher by the amount implied by Staff's CCOSS in this case. Below is a summary of the math (based on industrial class weightings from Exhibit 179 and the implied increase for those classes from Staff's CCOSS as reflected in its direct testimony):

Rate Class	Class Industrial kWh (From Exhibit 179)	Class Weighting (% of total from prior column)	Staff CCOS Implied Increase (Lange Direct, p. 25 table)	Weighted Increase (Product of prior 2 columns)
SGS	81,840,098	2.0%	4.82%	0.10%
LGS	741,326,274	18.0%	14.26%	2.57%
SPS	1,134,600,128	27.6%	24.14%	6.66%
LPS	2,154,909,649	52.4%	27.12%	14.21%
Overall	4,112,676,149	100%	**Implied Staff Industrial Increase**	**23.54%**

Staff argues that the precise rate that results from applying this 23.54% to the EEI starting point does not match the precise rate implied in its CCOS.[24] Well, of course it does not match, because it should not match. The precise rate implied in the Staff's CCOSS is not calculated consistent with the historical time period and methodology required by EEI in order to make it applicable to the benchmarking exercise, again, to make sure each utility's rates are compared on an apples-to-apples basis. The fact that, in effect, the benchmarking relies on a different "test period" and a different set of "billing units" means that the precise rates will not and should not match Staff's study precisely. But what result is an entirely accurate and appropriate comparison of what Ameren Missouri's Residential and Industrial rates, which were calculated consistent with the EEI benchmark, would have looked like if they had been higher by the percent Staff's study implies that they should be higher by, and how that compares to those benchmark national average rates that were determined on an equivalent basis. Ultimately, the headline that should not be lost is this: regardless of any nuanced details that one party or the other may advocate for in the subject calculation, Staff's study would produce rates far outside the mainstream of national norms.

2. Sub-issue 1B. Distribution Cost Allocation

As the Company explained in its Initial Brief, Staff nitpicks at a handful of the hundreds of individual allocation decisions that must be made in a CCOSS, and those nitpicks would produce only a small impact.[25] Staff's Initial Brief bears out that point.[26] And, Staff's Initial Brief does not attend to the fundamental flaws and biases in its own approach. Examples of Staff's speculative nitpicks regarding distribution cost allocation, and the remaining fundamental flaws and biases in Staff's approach are examined below.

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[24] EFIS Item No. 443, Staff's Initial Brief, pp. 50 – 51.
[25] EFIS Item No. 441, Ameren Missouri's Initial Post-Hearing Brief, pp. 13 – 14.
[26] EFIS Item No. 443, Staff's Initial Brief, pp. 6 – 19.

Staff nitpicks the Company's use of a historical distribution voltage review (referred to for convenience as the "Vandas study"). At page 7 of Staff's Initial Brief, Staff criticized the Company's CCOSS witness for not performing a check of the account balances for distribution accounts as they existed in 2009, when the subject distribution voltage review was conducted, against the account balances in the same accounts during the test year in this case.[27] However, the account balances in 2009 versus the test year are not relevant. The Vandas study is used to characterize distribution investments by the voltages they service.[28] Accordingly, the account balances are not relevant, and were not relied on by Company witness Thomas Hickman in performing the Company's CCOSS. The voltages served by the distribution investments are what is relevant and what was relied upon by Company witness Thomas Hickman in performing the Company's CCOSS.[29] In addition, the plant balances the allocation factors apply to are entirely current and updated, including all relevant SEP investment. This nitpick is unfounded.

Staff also argues that "[t]he distribution system today is much different than it was in 1994 when the Vandas study was performed."[30] The original Vandas study was performed in 1994, but it was redone in 2009. Mr. Hickman relied on the 2009 version for the reasonable percentage of components by voltage level.[31] Again, Staff does not specifically allege that the percentage breakdown of components has changed. Rather, Staff suggests it is **possible** that the percentage of distribution plant used to serve various voltage levels has changed over time.[32] Before relying on the 2009 version of the study though, Mr. Hickman assembled a team of distribution planning engineers,

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[27] Id., p. 7.
[28] Exhibit 37, Direct Testimony of Thomas Hickman, p. 7.
[29] Evidentiary Hearing Transcript ("Transcript"), p. 108, l. 24 – p. 109, l. 20.
[30] EFIS Item No. 443, Staff's Initial Brief, p. 7.
[31] Transcript, p. 108, l. 24 – p. 109, l. 20
[32] Transcript, pp. 465 – 467.

distribution standards engineers, and even certain personnel working on Smart Energy Plan projects to confirm the study is still reliable.[33]

Staff attempts to make a big ado about 70% of the Company's Smart Energy Plan projects' costs being allocated under the Company's CCOSS to small customers (the Residential and SGS classes).[34] But that fact is not surprising or alarming at all. Over 90% of Ameren Missouri's customers are small customers, over 60% of system demand occurs from the Residential and SGS classes, and over half of all energy usage is from small customers.[35] It is accordingly no surprise that 70% of those costs are allocated to them. This nitpick by Staff is much ado about nothing.

Next, Staff also implied that costs of recent Smart Energy Plan grid resiliency projects, efforts targeting worst performing circuits, and buildout of a private LTE network are disparate across voltages.[36] This nitpick does not hold up to further scrutiny. The fact that the Company has replaced a bunch of aging primary equipment with new primary equipment does not change the fact that there is primary equipment in the location where the Company replaced the old primary equipment. For allocation purposes, that is a change without a difference.

Staff also nitpicks the Company's use of a Minimum Distribution System ("MDS") method to classify distribution costs between demand-related and customer-related costs, because Staff misunderstands how the MDS method operates.[37] Staff states as follows in its Initial Brief, at page 10: "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." That statement is not true. Instead, as Mr. Hickman explains: "My view of the minimum sized system

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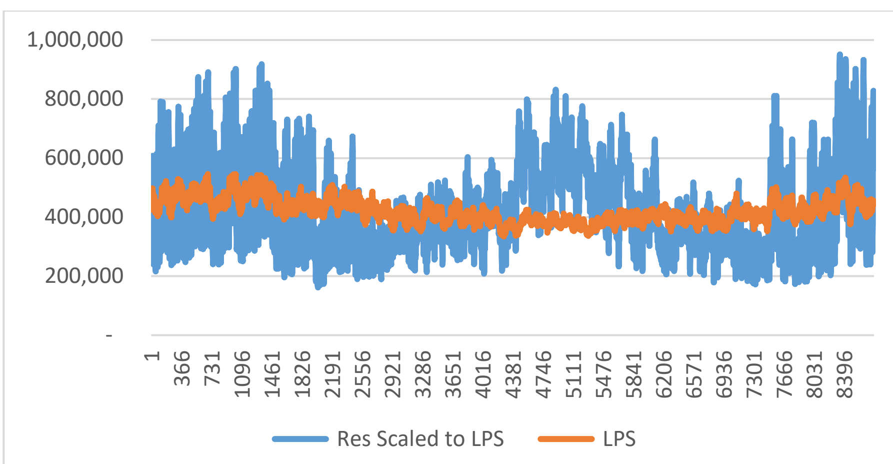
[33] Transcript, p. 108, l. 9 – p. 109, l. 20.
[34] EFIS Item No. 443, Staff's Initial Brief, pp. 13 – 14.
[35] See Exhibit 28, Direct Testimony of Nicholas Bowden, Ph.D., Schedule NSB-D1 (customer counts and energy usage data); & Exhibit 37, Surrebuttal Testimony of Thomas Hickman, p. 10, Table TH-4 (class NCP demand allocators show Residential plus SGS demands are 65% of the total).
[36] EFIS Item No. 443, Staff's Initial Brief, p. 8.
[37] Id., pp. 10 – 12.

approach is that it seeks to identify the assets necessary to interconnect customers between the transmission system and each customer service point."[38] Mr. Hickman's view makes sense in that secondary customers (even at minimum size) still use a fully built out primary system because a primary system is the most efficient way to move power over the distances that are necessary to cover Ameren Missouri's service territory.

But putting aside the actual use of the Vandas study and the practical operation of the MDS method, what does Staff use for distribution allocation? Staff uses what is effectively an energy allocator, which simply does not represent cost causation[39] and is unreasonable.[40] To illustrate the unreasonableness of using an energy allocator for what is otherwise appropriately classified as demand-related or customer-related distribution investment, Mr. Hickman used the same underlying data Staff did to produce its distribution allocator, focusing on the Residential and LPS classes.[41] Mr. Hickman created a "Residential Scaled to LPS" hourly load and graphed it against the hourly LPS load, which was depicted in Figure TH-1 of Mr. Hickman's rebuttal testimony and is reproduced for convenience below.[42]



[38] Exhibit 37, Surrebuttal Testimony of Thomas Hickman, p. 8, ll. 17 – 18.
[39] EFIS Item No. 441, Ameren Missouri's Initial Post-Hearing Brief, p. 11.
[40] Transcript, p. 295, ll. 3 – 8.
[41] Exhibit 37, Surrebuttal Testimony of Thomas Hickman, pp. 13 – 15.
[42] Id., p. 14.

The use of an energy allocator, like Staff essentially used, implies that an equal amount of distribution investment is needed to serve both classes, as the total Energy across all hours is the same. The difference in the maximum energy in the highest hour, which is what drives or causes the incurrence of distribution costs between the two classes is extreme: the highest hourly energy for the LPS class in the graph is approximately 545,000 kWh; the highest hourly energy for the Residential class (as scaled) in the graph is approximately 950,000 kWh. Staff's allocator implies the same amount of distribution assets would be required to serve customers using 545,000 kWh of energy in their single highest utilization hour as customers using 950,000 kWh of energy in their single highest utilization hour, which is demonstrably unreasonable.[43]

Compounding that unreasonableness, Staff's attempt to identify and directly assign customer-specific distribution infrastructure, such as customer-specific substations, double counts demand and biases Staff's study.[44] In Staff's Initial Brief, Staff quotes with added emphasis from the NARUC manual in pertinent part:[45]

> 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.]**

However, by not adjusting the demands for the allocation factor used for the rest of the substations, and thereby allocating some of that to the customer to whom the substation costs has already been directly assigned, a CCOSS is biased and double counts the customer's demand, like Staff's.[46] Understanding that Staff is desperate to significantly shift revenue responsibility away from the

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[43] Id.
[44] Transcript, p. 256, ll. 9 – 22.
[45] EFIS Item No. 443, Staff's Initial Brief, pp. 11 – 12.
[46] Exhibit 36, Rebuttal Testimony of Thomas Hickman, p. 9, ll. 10 – 17.

Residential and SGS classes and onto the LGS, SPS and LPS classes,[47] it should be no shock that the customer-specific infrastructure Staff seeks to identify and directly assign relates only to the large customer classes, thereby biasing the review. And then, Staff ignores the other side of the equation — equally important and offsetting assets that only provide direct benefits to a small subset of Residential and SGS customers, such as a lateral section of a primary distribution circuit that runs down a street in a Residential subdivision that has no function other than to serve that Residential subdivision. Under Staff's approach, this primary distribution circuit is allocated in part to the large customers who had the cost of similar infrastructure directly assigned to them.[48]

3. Sub-issue 1C. CCOSS overall

As explained hereinabove and in the Company's Initial Brief, Staff's desperate attempts to shift cost responsibility away from the Residential and SGS classes, and speculative nitpicks about Ameren Missouri, MIEC and MECG's CCOSS (which are very similar) should be seen for what they are: efforts seeking specific outcomes, instead of objectively assigning or allocating costs, with no nexus to cost causation. Furthermore, at page 24 of Staff's Initial Brief, Staff alleges: "…no filed study provides sufficient information to redesign customer and facilities charges to incorporate the effect of Riders B & C and to reasonably refine customer charges to vary by customer requirements, as opposed to obsolete class definitions." At page 26 of Staff's Initial Brief, Staff states: "CCoS studies … should not be solely relied upon for establishing each class' revenue requirement because they are not precise, and are not updated for changes from the studied revenue requirement and billing determinants to the ordered revenue requirement and billing determinants…." In spite of that, earlier in its Initial Brief, Staff claims its "CCoS study is reasonable and reliable, and Staff's recommended

[47] Described above in section I(A)1.
[48] Exhibit 36, Rebuttal Testimony of Thomas Hickman, pp. 7 – 8.

shifts in revenue responsibility [based on Staff's CCOSS] are appropriate."[49] Again, Staff cannot have it both ways, on the one hand claiming its CCOSS should be relied upon to significantly shift costs to large customers, and on the other hand, claiming it lacked data to conduct a reliable study and/or that no CCOSS is precise enough to establish class revenue requirements anyway.[50]

Staff's CCOSS is unreasonable and should be rejected. The Company's CCOSS, which is supported by MIEC and MECG as well, is reasonable. The Company's CCOSS should be used in this case and as a starting point for the Non-Residential rate design working docket ordered in the Company's last electric general rate case, File No. ER-2021-0240.

B. Minimum Demand Charge if Customer Charges Differentiated, Sub-issue 1E.a.

The Company appreciates the clarification provided by Staff through its Initial Brief regarding Staff's recommended minimum demand charge only applying to the Ultimate Savers rate plan, and not applying to the Smart Savers rate plan.[51] However, upon further review of Staff's proposed minimum demand charge, the Company is compelled to refine its position. To be clear, the Company continues to support a differentiated customer charge as explained in its Initial Brief.[52] As also explained in the Company's Initial Brief, the Company does not push customers toward high-differential rates, like the Ultimate Savers rate plan.[53] And, the Company continues to recommend Staff's alternative proposal for a minimum demand charge equal to the difference in the customer charge for the Ultimate Savers rate plan of $4 be rejected for the reasons explained in its Initial Brief.[54]

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[49] EFIS Item No. 443, Staff's Initial Brief, p. 4.
[50] EFIS Item No. 441, Ameren Missouri's Initial Post-Hearing Brief, p. 21.
[51] EFIS Item No. 443, Staff's Initial Brief, pp. 32 – 33 & EFIS Item No. 441, Ameren Missouri's Initial Post-Hearing Brief, p. 24.
[52] EFIS Item No. 441, Ameren Missouri's Initial Post-Hearing Brief, pp. 22 – 23.
[53] Id., pp. 24 – 25.
[54] Id.

But the Company is seriously concerned that Staff's alternative minimum demand charge proposal would be a very poor introduction to demand charges for customers and would very likely trigger customer confusion and frustration. Therefore, prioritizing customers' experience, if the Commission is considering ordering Staff's alternative minimum demand charge for the Ultimate Savers rate plan, the Company instead suggests that the Commission decide to not differentiate the customer charges for Residential rate plans. Although the differentiated customer charges across Residential rate plans better align rates with customer-related costs and provide opportunities for customers to better manage their bills, to avoid such a poor introduction to demand charges for customers and avoid likely customer confusion as presented by Staff's alternative minimum demand charge, the Company would rather the Commission not approve the differentiated customer charges across Residential rate plans. If the Commission took this approach instead of differentiating the customer charges, it is still appropriate to increase the customer charge for all rate plans to $9.50 as discussed in the Company's Initial Brief.[55]

C. Residential Rate Design Changes, Sub-Issue 1F.

If the Commission orders a high-differential time-of-use ("TOU") rate to be the new default for all Residential customers with AMI metering in this case, Staff recommends an intermediate overlay design for one year before customers are shifted to the high-differential TOU new default rate.[56] As an initial point, the Company continues to be extremely concerned about a high-differential TOU rate being the new default for all Residential customers with AMI metering due to expected bill impacts. Company witness Steven Wills especially noted during the evidentiary hearing that bill impacts could potentially be 20% plus or minus for electric space heating customers

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[55] Id., p. 23.
[56] EFIS Item No. 443, Staff's Initial Brief, p. 28.

in the winter on top of the 5% increase arising from the agreed upon revenue requirement.[57] Moreover, Ameren Missouri has come a long way on modernizing rate design — with hundreds of thousands of Residential customers on a TOU rate.[58] However, there is still work to be done as the Company finishes up deployment of AMI metering to the remaining one-third of customers.[59] Similar to the Company's concerns with altering TOU default timeframes and eliminating rate plans,[60] tinkering with Residential default rate designs at this point would likely trigger severe customer confusion and frustration, and also cause wasteful duplicative costs of redesigning a customer journey that has already been successful in moving hundreds of thousands of Residential customers to TOU rates.

Regarding Staff's alternative intermediate overlay design though, it must first be pointed out that Staff's alternative design was presented for **the first time ever** at the evidentiary hearing during Staff witness Sarah Lange's live testimony. Ms. Lange even acknowledged on cross-examination by Company counsel during the evidentiary hearing that billing units do not exist for Staff's new recommended intermediate overlay, and would have to be developed.[61] Given the tight timeframe for turning around compliance tariffs to meet the statutory operation of law date for general rate cases, which utilities justifiably place heavy reliance on in timing rate cases and developing business plans and expectations, it would be wholly inappropriate to try to develop new analyses to implement a recommendation made by Staff for the first time at hearing given that Staff had three opportunities, after months of auditing the Company's case, to propose and support proposals. Thus, the Commission should not order a high-differential TOU rate as the new default for all Residential

[57] Transcript, p. 187, l. 21 – p. 189, l. 23.
[58] Exhibit 39, Direct Testimony of Steven Wills, p. 7, Table 2.
[59] Transcript, p. 245, ll. 3 – 15.
[60] EFIS Item No. 441, Ameren Missouri's Initial Post-Hearing Brief, pp. 25 – 29.
[61] Transcript, p. 453, ll. 14 – 23.

customers with AMI metering in this case, but also should not approve Staff's recommended intermediate overlay design.

D. Rate structure studies/data, sub-issue 1H.

The Company and Staff seem to now agree that the working docket to be established per the Commission's Report and Order in the Company's last electric general rate review is the best venue for discussion of what studies and data are reasonably available and necessary for exploring Non-Residential, Non-Lighting rate designs.[62] At page 24 of Staff's Initial Brief, Staff suggests that: "…a meaningful rate modernization workshop would provide an opportunity for Commission input in determining which customer characteristics should be considered in the development of new rate structures, as well as an opportunity for all stakeholders to access information concerning what data is already available in one form or another, and what information may not be realistically obtainable." The Company is similarly hopeful that stakeholders can work collaboratively to determine what information can be **reasonably** compiled, shared, and used for developing modern Non-Residential rates.[63] However, the Company continues to be only cautiously optimistic given Staff's novel methodologies, like Staff seeking to develop **individual customer** costs of service based on mapping specific asset costs to specific customers, instead of seeking to develop **class** costs of service based on reasonable allocations.[64]

E. Ameren Missouri's Proposed Two-Way Rate-Switching Tracker, Issue 1I.

Staff appears to misunderstand Company witness Wills' testimony from the Charge Ahead case, File No. ET-2019-0132, and discussion of the Company's proposed two-way rate-switching tracker in this case. Staff's Initial Brief states:

[62] EFIS Item No. 441, Ameren Missouri's Initial Post-Hearing Brief, p. 41; & EFIS Item No. 443, Staff's Initial Brief, p. 24.
[63] EFIS Item No. 441, Ameren Missouri's Initial Post-Hearing Brief, p. 41.
[64] Id.

> However, in file ET-2018-0132 Mr. Wills testified that 'My expectation is that no TOU rate is likely to be established that doesn't fully cover the marginal cost of service and make a contribution to covering the Company's fixed costs so that those customers that do charge during off-peak times will still provide positive margin when netting the reduced revenues with the reduced incremental costs of serving EVs.' At the hearing in this case Mr. Wills testified that he believes that the Ultimate Savers, Smart Savers and Overnight Savers rate plans each cover the marginal cost of service and make a contribution to covering the Company's fixed costs.[65]

Mr. Wills actually testified that the Ultimate Savers, Smart Savers, and Overnight Savers rates cover the marginal cost of service and make a contribution to fixed costs "…on longer times scales at kind of current energy market environments… ."[66] Since those rates do not cover all of the fixed costs of the Company providing service, those rates negatively impact the Company's opportunity to recover its revenue requirement — i.e., they cause revenue erosion. Hence, the Company's proposed two-way rate-switching tracker seeks to track any revenue erosion and excess revenues from the switching between rate plans by customers.

F. Changes to Continuing Property Record, Issue 2.

Staff continues to misunderstand the foundational point of mass property accounting: because the quantity is extremely high and per-unit cost of mass property is relatively low, mass property assets simply have less detailed accounting requirements than other types of property.[67] Under the Company's current processes, which have been followed for the last 17 years consistent with the Uniform System of Accounts ("USoA"), and which are relied upon by many other utilities across the country, when the Company initially places mass property assets into service, the general description of the mass assets in a category along with the quantity placed in service by vintage year and average

[65] EFIS Item No. 443, Staff's Initial Brief, p. 48, internal citations omitted.
[66] Transcript, 204, l. 17 – p. 205, l. 3.
[67] Exhibit 47, Rebuttal Testimony of Mitchell Lansford, p. 8.

cost per unit are recorded.[68] Because the specific asset being retired cannot practically be identified (as no location information has been or is required to be retained in the Company's accounting records that would allow for the identification of a specific mass property asset) within the Company's mass property accounting records, the vintage and quantity of assets within a category to be retired are selected using statistical analysis.[69]

Staff incorrectly asserts that the Company's PowerPlan software[70] may not "like a pole" and "likes" a vintage of pole with lower average cost "better" — i.e., Staff alleges that the Company's methods will produce biased estimates of lower average costs of retired mass property assets so that higher value assets remain in rate base, and at least implies, rate base would therefore be greater.[71] First, the Company's estimates are free of bias. Second, the claim that rate base would necessarily be greater is false. Each point is addressed below.

With respect to the claimed bias, the estimates rely on the Iowa survivor curves that underlie the depreciation rates ordered by the Commission. In fact, The Company's current and pending depreciation rates and related Iowa survivor curves for mass property are those recommended by *Staff*.[72] Once these parameters are set as part of a general rate case, the Company calculates its

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[68] Exhibit 48, Surrebuttal Testimony of Mitchell Lansford, p. 10; & Exhibit 43, Rebuttal of John Spanos, pp. 17 – 18.
[69] Exhibit 184, Company's Response to Data Request MPSC 209.1. It should also be noted that Staff's Initial Brief actually reflects a *change* in the recommendation reflected in its pre-filed testimony and hearing testimony, now wanting not only an actual vintage year of every single mass property asset that is retired to be recorded (despite the practical inability to know that year) but also wanting each retirement to reflect the item's "book cost when acquired," which Staff had not recommended before. EFIS Item No. 443, Staff's Initial Brief, p. 67. This is what is done with retirement unit property but the USoA intentionally treats retirement unit property and mass property differently, for a reason, as outlined in the Company's Initial Brief and this Reply Brief.
[70] PowerPlan software is widely used in the industry.
[71] EFIS Item No. 443, Staff's Initial Brief, p. 54.
[72] The comparison of the stipulated depreciation rates and parameters and those sponsored by Staff witness Cedric Cunigan demonstrate that the depreciation rates and parameters match those sponsored by Staff. See April 7, 2023 Stipulation and Agreement, Exhibit E; Exhibit 117 Direct Testimony of Cedric Cunigan, Exhibit 118 Rebuttal Testimony of Cedric Cunigan, & Exhibit 119 Surrebuttal Testimony of Cedric Cunigan, respectively. With respect to current depreciation rates and parameters approved in File No. ER-2021-0240, see November 24, 2021 Unanimous Stipulation and Agreement, Exhibit F, and Exhibit 201 Staff's Direct Cost of Service Report, Exhibit 211 Rebuttal Testimony of Cedric Cunigan & Exhibit 227 Surrebuttal Testimony of Cedric Cunigan.

estimates for retirements of mass property using the ordered depreciation parameters and Iowa survivor curves via its PowerPlan software **without any other inputs** (i.e., free of any bias).

Nationally renowned depreciation expert, Company witness John Spanos provided an accurate example of the retirement process using the retirement of 10 40-feet distribution poles in a rural area south of St. Louis, which would involve Account 364, Poles and Fixtures. Because the poles are mass property assets, specifically identifying the actual vintage of an asset is not realistic. Illustrating the Company's actual process, Mr. Spanos explained that the detailed property system for distribution poles in the south St. Louis area of 40-foot poles are identified as having been installed from 1965 to 1975. The Company's software system would not pick which vintage it "likes" better, or otherwise bias the estimate, but rather would retire 10 poles with vintages of 1965 through 1975 on a percentage basis consistent with the current survivor curve that underlies the Commission-approved depreciation rates, and which is reflected in the PowerPlan software.[73]

At the evidentiary hearing, Mr. Spanos further explained what is being estimated by the Company's software in response to a question from the RLJ:

> **Q. And is it industry standard to use software to record this? To, I guess, estimate this?**
> A. The process of -- and maybe to help clear up an understanding of what is being estimated is I'll take the poles account for example. The – not every pole has a stamp on it. Okay. So it's not identified with a specific vintage. So again, if you have a storm that occurs and you have 50 poles that got replaced all at once, you can identify how many poles were replaced, but you won't know the stamp because one, it doesn't exist. I mean, if it was a storm, it could have blown away or it's been sitting there for 70 years and you don't have it ident -- able to identify it.

[73] Exhibit 43, Rebuttal Testimony of John Spanos, p. 18, ll. 7 – 20.

> So the survivor curve, and what you do, you're not doing a statistical analysis only when developing a survivor curve. You are using judgment that understands the ratio and mortality of poles. So is it able to establish, okay, 40 poles were built in the '60s or -- and used in the '60s, so now we're going to apply the '60s vintage to the poles that got retired. That's a reasonable expectation. So the dollar value that is being assigned is much more in line with how -- the example that Mr. Graham put out in his opening remarks. You have a much narrower view of what the actual average cost is of those dollars. And that's why there's the ability to get that recorded more timely than waiting to go find -- send the field personnel to go out and try to figure out what that vintage was is, you know, an impossible task and it's going to keep them from keeping the power on for somebody else.[74]

The Company's software system's estimates are accordingly reasonable and reliable.

With respect to Staff's claim that a bias towards retirement of lesser average cost values results in greater rate base, the Company demonstrated in its Initial Brief that the recording of a retirement has no direct impact on rate base whatsoever.[75] And while it is true that **future** rate base levels are indirectly impacted by retirement entries, it is not true that this creates a bias towards higher future rate base. In fact, retiring lower average cost mass property assets (which underlies Staff's expressed concerns) produces the opposite effect, that is, it would actually result in greater depreciation expense,[76] and thus greater future depreciation reserves, producing a **lower** future rate base.

To the extent that the Company's process does ever result in a difference in rate base versus what it otherwise would have been, the resulting rate base is still the appropriate rate base on which to set rates. This is because that rate base will reflect the difference between the gross investment in plant dedicated to the service of customers, less the return of capital that has already been

[74] Transcript, p. 504, l. 18 – p. 505, l. 24.
[75] EFIS Item No. 441, Ameren Missouri's Initial Brief, pp. 52 – 53.
[76] Retiring a biased lower average cost asset would result in depreciation continuing to be calculated based on a higher cost unit and therefore increase depreciation.

accomplished through the application of Commission-approved depreciation rates applied against that gross plant value. Said another way, the Company and customers will both be made whole, whether depreciation expense set in a given case was slightly "too high" or "too low." If the depreciation expense set in a rate case is too high, customers will have paid slightly more while those rates were in effect (i.e., will provide slightly higher return **of** for a time), but will have a lower rate base going forward as a result since every dollar of depreciation expense is adding to the depreciation reserve and lowering rate base. And vice versa, if depreciation expense is slightly too low, customers will have paid less, but will have a higher rate base going forward.

Staff has repeatedly stated it has no means of assessing the Company's estimates.[77] In reality, the accuracy of estimates used in the ratemaking process can be assessed. Common methods of assessing the accuracy of estimates include assessing the inputs and estimation processes, review of subsequent results, and comparisons to independently determined estimates.[78] Staff, by its own admission, has not even attempted to assess the accuracy of the Company's estimates. However, we know Staff has the means to perform such assessments given the even more complicated assessments Staff performed in this case on the accuracy of the Company's estimated effect of weather on billing units,[79] dispatch of generating units,[80] and return on equity,[81] just to name a few.

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[77] Exhibit 118, Rebuttal Testimony of Cedric Cunigan, p. 5, ll. 6 – 9; & EFIS Item No. 443, Staff's Initial Brief, p. 65, Footnote 214.

[78] Reading a single DR 209.1s1 taken out of context where the Company explains an example of where all the characteristics of a single pole retirement may not match the estimate for that specific pole exactly is not an appropriate method of assessing the accuracy of an estimate.

[79] E.g., Exhibit 156, Direct Testimony of Hari Poudel, Ph. D.

[80] E.g., Exhibit 139, Direct Testimony of Shawn Lange.

[81] E.g., Exhibit 166, Direct Testimony Seoung Joun Won.

Staff also incorrectly suggests that the estimating process is circular whereby future survival curve choices self-reflect past and present survival curve choices rather than actual plant in service.[82] Mr. Spanos explained in direct testimony how Iowa-type survivor curves are used as follows:

> Iowa-type curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.
>
> Iowa-type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.
>
> The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 57-R2 indicates an average service life of fifty-seven years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a low height, 2, for the mode (possible modes for R type curves range from 1 to 5).[83]

Moreover, as quoted above, Mr. Spanos explained that developing a survivor curve requires "using judgment that understands the ratio and mortality of poles."[84] On cross-examination at the evidentiary hearing, Staff witness Cedric Cunigan even agreed that "[s]urvivor curves are estimates based on statistical analysis **and judgments** about the service life of assets."[85] Regular depreciation studies aid that judgment because such studies "allow for the proper inquiries, review of operational data, and statistical analysis to recommend adjustments to the Company's survivor curves where appropriate, which are then incorporated into the technology used to process the retirements."[86] Thus, there are reasonable checks at regular intervals to guard against the alleged circularity arising.

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[82] EFIS Item No. 443, Staff's Initial Brief, p. 57. OPC's Initial Brief similarly confuses the use of survivor curves for depreciation rates and mass property asset retirements. EFIS Item No. 440, OPC's Initial Brief, pp. 14 – 15.
[83] Exhibit 43, Direct Testimony of John Spanos, p. 28, l. 21 – p. 9, l. 13.
[84] Transcript, p. 505, ll. 7 – 10.
[85] Id., p. 554, ll. 12 – 15, emphasis added.
[86] Exhibit 43, Rebuttal Testimony of John Spanos, p. 18, l. 20 – p. 19, l. 2.

Although Staff attempts to completely ignore the practical realities, the Commission should not and the Company cannot. Staff uses the fact that **some portion** of the Company's approximate 900,000 poles have tags used in the Company's pole inspection program[87] to extrapolate that there is, going forward, a practicable way, for the Company to tag **all other** mass property assets categories and correlate those tags to the Company's CPR.[88] The fact that there can be no correlation of a specific asset to the Company's CPR without tracking the location of that asset (which again is not required for mass property) notwithstanding, Staff's recommendation of tagging all other mass property assets directly contradicts Staff witness Cedric Cunigan's testimony at the evidentiary hearing when cross-examined by Company's counsel:

> Q. So under your proposal to modify the retirement of mass property within the Company's continuing property record, wouldn't that practically mean that Ameren Missouri field personnel would have to find and note the asset ID tag for every asset being retired on a work order?
> A. To tie it to the continuing property record, there would need to be some kind of tie between the -- the asset ID and the continuing property record and some kind of identification on the asset in the field. I believe -- I don't have it in front of me now because the judge has my copy, but on that spreadsheet from -- attached to DR 439, there is an asset ID tag or a -- I'm trying to remember it. There is a tag number associated with those poles.
> Q. So my question was wouldn't that practically mean then though that Ameren Missouri field personnel would have to try to find and note any tag, asset ID tag for every asset being retired on a work order?
> A. Yes. They would have to identify the asset somehow.
> Q. And to your knowledge are asset IDs for mass property currently maintained in the Company's work order system today?
> A. Asset IDs for certain equipment, like I said, such as the poles, they do have asset tags for those. **I can't say it for every account that the Company has mass property on**.
> Q. So, for example, the wires or conductor, are you aware of any tags with the asset ID on it for that type of asset?
> A. **For wires I am not aware of that.** I think also -- well, I'll let you ask your next question.

[87] EFIS Item No. 443, Staff's Initial Brief, pp. 60 – 62, quotes from Mr. Lansford's testimony at the evidentiary hearing.
[88] Id., p. 63.

> Q. Is your recommendation then that the Company begin labeling every mass property asset like a foot of conduit -- or I'm sorry, a foot of conductor with an asset ID so that it can be recorded in the work order system?
> A. **I think we would have to look at each individual asset group or account.** Because when you look at mass property, I don't know if someone said it earlier or not, but it's for homogenous high count assets but also low value. And we have some assets in this -- in these accounts that are approaching a million dollars, and I wouldn't consider that low value. And so there may be some wiggle room in there where we can say, you know, You may not have to do this tagging for, you know, wires. But if you can do it and it's more feasible, we might need to narrow that down.
> Q. So I might clarify then, is this a potential revision of your proposal that you would not suggest that this would be required for every type of asset group within mass property assets?
> A. **My testimony did not outline specific accounts, but I would be open to discussions of the accounts and assets that this would be -- this new process could be used on.**[89]

Staff's fixation on poles, a portion for which tagging occurs under the Company's pole inspection program, is misplaced, but tagging of a portion of the Company's 900,000 poles should certainly not be extrapolated as feasible or even possible for all other asset types and accounts. As quoted above, Mr. Cunigan admits he is not aware of each foot of conductor or "wires" being tagged, nor has he explained how this could even be done. This is confirmed by Company witness Lansford as quoted in Staff's Initial Brief: "I'm definitely aware that we have no asset IDs on any of our overhead conductor."[90] Mr. Lansford estimated during the hearing that the Company had over a hundred million feet of overhead conductor recorded in Account 365.[91] Mr. Cunigan expressly recognized there is "wiggle room" such that it may **not** be feasible for some accounts, like conductor, to follow the process Staff outlines.

Realizing this, Mr. Cunigan expressed openness to discussions of the accounts and assets that

[89] Transcript, p. 555, l. 8 – p. 557, l. 17, emphasis added.
[90] EFIS Item No. 443, Staff's Initial Brief, p. 60 (quoting from Transcript, p. 542, ll. 16 – 17).
[91] Transcript, p. 535, ll. 2 – 7.

Staff's proposed process for tagging individual mass property assets and field personnel locating and sending the tag information to the property accounting group process[92] could be used on. Notably, Staff never mentions in its Initial Brief that, at a minimum, discussions are needed to look at individual asset groups and accounts to see if it is feasible to narrow down which accounts and assets, if any, Staff's proposed tagging process would be practical to be used on. Staff also conveniently never addresses in its Initial Brief the cost and time delays[93] that would be incurred through implementation of Staff's proposed process, nor has any clearly articulated benefit of such a costly effort been offered, other than Staff's plainly wrong claims that there is a bias toward higher future rate base and that Staff is powerless to assess estimates. And, Staff only speculates that incurring such costs and triggering time delays for years to come **may** yield more accurate records, perhaps not in customers' favor.[94] Staff's bewildering disregard of the costs to be borne by customers and time delays for little, if any, benefit to customers should cause its proposal to be rejected out of hand.

Nevertheless, even ignoring all the information and evidence presented by the Company in this case on Issue 2 (the Commission should not), the evidentiary record in this case simply does not support the Commission ordering the Company to change its process for mass property asset retirements in this case. As quoted above, Mr. Cunigan acknowledged that Staff's proposed process might not work for all asset types and expressed openness to further discussions. Staff did not seek discovery of the details of the PowerPlan estimation of mass property retirements works, and only speculates that it could be biased, an issue addressed above. Mr. Cunigan additionally confirmed he is not aware of how other regulated utilities in Missouri handle mass property retirement. Thus, with such a lack of understanding of the underlying process and practical implications of changing the

[92] Id., p. 558, ll. 4 – 22.
[93] Id., p. 503, ll. 9 – 18 & p. 508, l. 23 – p. 509, l. 10.
[94] Transcript, p. 570, ll. 5 – 9.

process, a reasonable outcome of this case would be for the Commission to order the Company, Staff, OPC and any other interested stakeholders, which may include other regulated Missouri utilities using the same mass property retirement estimation methods, to meet and discuss the mass property retirement process further. This would allow for a detailed explanation of the estimation process, an evaluation of any bias therein and impacts of any such bias, and an evaluation of the feasibility of alternative processes for the retirement of mass property assets, among other things.

II. <u>Reply to Renew's Initial Brief</u>

Renew Missouri raised the issue of whether the Net Metering Statute requires that optional TOU rates offered to non-net metered Residential customers be offered to net metered Residential customers in its Initial Brief under sub-issue 1F.b. Sub-issue 1F.b. relates to what changes, if any, should be made to the deployment of Residential TOU rate plans. The Company understood sub-issue 1F.b. to relate to Staff's recommended changes to the deployment of Residential TOU rate plans and did not address Renew's new interpretation of Missouri's Net Metering Statute in its Initial Brief. Similarly, no other party, except for Renew, addressed Renew's new interpretation of the Net Metering Statute in their initial briefs.

Although it is unclear whether the issue of the Net Metering Statute being interpreted by Renew to require all optional TOU rates to be offered to net metered Residential customers was a disputed issue for the evidentiary hearing, Ameren Missouri will take this opportunity to reply to Renew's new interpretation and explain the following: 1) why the Net Metering Statute does **not** require all optional rate plans to be offered to net metered Residential customers; 2) the implied historical interpretations of the Commission regarding optional rate plans not being offered to net metered Residential customers; 3) the economic underpinnings that support not offering higher-price-differential TOU rates to net metered customers under the netting across billing period construct prescribed by the Statute; and 4) the task force created just last year (2022 Legislative Session) to evaluate the necessary legislative changes to promote the overall public interest. Furthermore, the Company explains why Renew's request for yet another study should be rejected.[95]

A. Background

Section 386.890, RSMo., which is known as the "Net Metering and Easy Connection Act" (the "Act"), initially became effective in 2007. Subsection 2 of the Act sets out definitions, and provides the following:

> (5) "Net metering", using metering equipment sufficient to measure the difference between the electrical energy supplied to a customer-generator by a retail electric supplier and the electrical energy supplied by the customer-generator to the retail electric supplier over **the applicable billing period. (Emphasis added)**

A "billing period" is not separately defined in the Act, but the term is commonly understood and defined in Commission Chapter 13 rules for Residential customer service and billing practices as follows:

> (C) Billing period means a normal usage period of not less than twenty-six (26) nor more than thirty-five (35) days for a monthly billed customer nor more than one hundred (100) days for a quarterly billed customer, except for initial, corrected, or final bills….[96]

Under subsection 3 of the Act, a retail electric supplier shall *inter alia*:

> (2) Offer to the customer-generator a tariff or contract that is identical in electrical energy rates, rate structure, and monthly charges to the contract or tariff **that the customer would be assigned if the customer were not an eligible customer-generator** but shall not charge the customer-generator any additional standby, capacity, interconnection, or other fee or charge that would not otherwise be charged if the customer were not an eligible customer-generator… **(Emphasis added)**

Subsection 5 of the Act prescribes the netting method in pertinent part:

> 5. Consistent with the provisions in this section, the net electrical energy measurement shall be calculated in the following manner:

[95] Transcript, p. 88, ll. 4 – 25. Renew's counsel clarified Renew's request in this case as follows: "We're only asking for an order to conduct the study."
[96] 20 CSR 4240-13.015(1)(C).

> (2) If the electricity supplied by the supplier exceeds the electricity generated by the customer-generator **during a billing period**, the customer-generator shall be billed for the net electricity supplied by the supplier in accordance with normal practices for customers in the same rate class;
>
> (3) If the electricity generated by the customer-generator exceeds the electricity supplied by the supplier **during a billing period**, the customer-generator shall be billed for the appropriate customer charges for that billing period in accordance with subsection 3 of this section and shall be credited an amount at least equal to the avoided fuel cost of the excess kilowatt-hours generated **during the billing period**, with this credit applied to the following **billing period**…. **(Emphasis added)**

Shortly after the Act became effective, in January 2008, although Ameren Missouri offered Residential 1(M) customers a TOU rate known as the "Optional Time-of-Day Rate," the Commission approved changes to the Company's net metering tariff schedule, Schedule 1, Sheet No. 8, wherein net metering customers were **expressly not eligible** to participate in that optional TOU rate.[97] In compliance with subsection 3 of the Act, net metering customers were eligible for the 1(M) regular rate that the net metering customer would otherwise be assigned if the customer were a net metering customer, but net metering customers were not eligible for the optional TOD rate.[98] Indeed, the current "Grandfathered Option TOD (Time-of-Day) Rate Pilot," which was included in the tariffs to be updated in this case attached to Company witness Michael Harding's direct testimony, still shows: "Participation shall exclude customers with a net metering agreement."[99]

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[97] https://www.efis.psc.mo.gov/mpsc/CommonComponents/viewdocument.asp?DocID=3725572&Version=16. Click on Tracking No. JE-2003-01349. Then follow to the "New Tariff Submission.pdf" file. At page 38 of 82 of the pdf, in Section 1 (Application), second paragraph, "Net metering cannot be elected in conjunction with 'Optional Time-of-Day Rate' service of any of the Company's rate schedule." The quoted language remained on Sheet No. 8 through June 30, 2023, when the sheet was cancelled in a tariff reorganization. See pages 36 and 37 of the pdf, in Section 1 (Application), second paragraph.

[98] The issue of the Company's prior TOU pilot rates came up during questions from Chairman Rupp (then Commissioner Rupp) to Company witness Steven Wills at the On-The-Record Presentation of the Stipulations in File No. ER-2019-0335, EFIS No. 246, Transcript – Volume 16 (On-The-Record Presentation – Jefferson City, MO – March 4, 2020), at p. 225, l. 4 – p. 227, l. 5.

[99] Exhibit 32, Direct Testimony of Michael Harding, Schedule MWH-D1, Sheet No. 54.3, provision c.

In Ameren Missouri's 2019 electric general rate review, File No. ER-2019-0335, a new default, very mild TOU rate, now called the "Evening/Morning Saver" rate plan, was approved based on a stipulated agreement among signatories.[100] Per the 2019 Stipulation, new Residential customers or new accounts with an Advanced Metering Infrastructure ("AMI") meter were to be directly placed on the new default TOU rate, and Residential Customers who did not have an AMI meter were to be defaulted to the new default TOU rate within six months of an AMI meter being installed.[101] Renew did not sign the Stipulation, but indicated it had no objection to it.[102] During the On-The-Record Presentation ("OTR") in File No. ER-2019-0335 of the rate design stipulation, the question of how net metered customers or "customer-generators" under the terminology in the Act would be defaulting to the Evening/Morning Saver TOU rate plan, but net metering customers would not be eligible for the advanced TOU rate plans, was discussed.[103] At the OTR, Commissioner Holsman asked Renew's counsel, Tim Opitz, about net metering and advanced TOU rate options, and the following response was provided:

> COMMISSIONER HOLSMAN: Yes. Was there any discussion concerning the net metered customers and the prohibition on their ability to have time-of-use?
>
> MR. OPITZ [representing Renew in the 2019 case]: Commissioner, I don't want to get into any discussions that would be considered settlement discussion. I will say that for Renew Missouri's perspective the net metering customers were – some class of customers were very concerned about potentially being forced on to certain rates in the future. Whether they would be prohibited was not something we specifically identified within our positions we've taken.

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[100] File No. ER-2019-0335, EFIS Item No. 229, Corrected Non-Unanimous Stipulation and Agreement, filed March 2, 2020, at pp. 9 – 10, para. 27(a); & File No. ER-2019-0335, Order Approving Stipulations and Agreements, effective March 28, 2020, ordering para. 1 (approved the Stipulation).
[101] Id., at p. 9, para. 27(a)ii & iii.
[102] File No. ER-2019-0335, Order Approving Stipulations and Agreements, effective March 28, 2020, at p. 1.
[103] ER-2019-0335, EFIS Item No. 246, Transcript – Volume 16 (On-The-Record Presentation – Jefferson City, MO – March 4, 2020), at p. 245, l.15 – p. 247, l. 18.

In Ameren Missouri's direct case in File No. ER-2021-0240, Company witness Steven Wills addressed the issue of net metering customers not being eligible for optional advanced TOU rate plans stating in pertinent part:

> **Q. Does the Company share the Commission's goal of making all of its rate options accessible to net metered customers?**
>
> A. Yes. In fact, I testified at length in the 2019 case, and to some extent in this direct testimony already, about the fact that one of the driving factors behind the need to modernize rate design is to provide for the right price signals for, and equitable cost allocation to, customers adopting the rapidly emerging energy-related technologies that are transforming our industry. Behind-the-meter solar generation is among the most prominent of those technologies. The best way to encourage adoption of technologies in an economically efficient manner is for rates to reflect the cost structure of the utility. To the extent that the advanced rates represent the most cost-reflective rates for residential customers, these are the rates that make the most sense to make available to net metered customers. That said, there are certain barriers in the language of Missouri's Net Metering and Easy Connection Act ("the Act") – the legislation that defines the way net metering operates in the state – to offering appropriate net metered TOU rates to customers.
>
> **Q. What are the barriers you have identified to offering effective TOU rates to net metered customers?**
>
> A. While I am not an attorney, some of the provisions of the Act plainly conflict with the principles of effective TOU rates. For example, the Act requires that "[f]or a customer-generator, a retail electric supplier shall measure the net electrical energy produced or consumed during the billing period…." While that sounds like a pretty accurate and fair description of the concept that is net metering, it creates a framework where netting of usage and generation must occur over the entirety of the billing period. Any kWh of generation, regardless of the time it occurs, must be netted against any kWh of usage, regardless of the time of use. Said in another way, to measure net consumption across the whole billing period, all kWh must be valued equally, rather than at unique rates that depend on the timing of use and/or generation. This phenomenon of valuing kWh equally regardless of the time of use is reinforced later in the Act, when the Act dictates that a customer that has net zero usage over the billing period shall have a bill that reflects zero energy charges. If kWh of usage and generation could be valued by time-varying rates that apply different charges and credits to different kWh over the billing period, net zero usage over the entire billing period would not necessarily result in zero energy charges. At the time the Act was passed, TOU rates were not prevalent in Missouri, and this issue probably was not top of mind of the Legislature. However, as rate designs have evolved, the language does create some limitations for the application of net metering to TOU rates.

Q. What would be appropriate terms on which TOU rates could or should be applied to net metered customers?

A. Most importantly, for effective price signals to exist for net metered customers on TOU rates, net metering legislation would need to define netting to take place within each defined TOU period. Next, legislation should provide that generated kWh should not receive a premium (e.g., peak, mid-peak) price unless they are offsetting a premium kWh of usage. If these principles are observed, then the customer-generator will still receive actionable price signals that encourage more efficient use of the system. If not, the netting process will distort the price signals and reduce the incentive to use energy more efficiently, and set up the possibility of gaming the TOU prices once customers start to pair storage with behind-the-meter generation. This could occur if netting is allowed to cross TOU periods. This practice would allow a customer with a battery to essentially arbitrage the energy supplied by the Company during off-peak periods by storing it and selling it back at a significant premium in the on-peak period. This transaction would be unrelated to the solar generation, which is the reason for the net metering to exist in the first place, but would leverage that arrangement to create bill reductions for the customer that would not be accompanied by commensurate cost reductions on the system.[104]

Renew witness James Owen filed rebuttal testimony in File No. ER-2021-0240, which addressed two issues — neither was related to net metering Residential customers having access to optional, advanced TOU rate plans.[105] Net metered Residential customers having access to advanced TOU rate plans was not an issue for the evidentiary hearing, and was not a decision point in the Commission's Report and Order in File No. ER-2021-0240.[106]

In the 2022 Missouri Legislative Session, section 386.885 of the Revised Statutes of Missouri was promulgated, and the section became effective August 28, 2022. Section 386.885 establishes the "Task Force on Distributed Energy Resources and Net Metering." Under subsection 2 thereof, the Task Force's mission is described as follows:

2. The task force shall conduct public hearings and research, and shall compile a report for delivery to the general assembly by no later than December 31, 2023. Such report shall include information on the following:

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[104] File No. ER-2021-0240, Exhibit 17, Direct Testimony of Steven Wills, p. 38, l. 3 – p. 40, l. 11.
[105] File No. ER-2021-0240, Exhibit 800, Rebuttal Testimony of James Owen on Behalf of Renew, pp. 3 – 4.
[106] File No. ER-2021-0240, Report & Order, effective February 12, 2022.

(1) **A distributed energy resources study, which shall include a value of solar study along with the practical and economic benefits, challenges, and drawbacks of increased distributed energy generation in the state;**

…and

(3) **Potential legislation, including but not limited to changes to the net metering and easy connection act, if any, that would promote the overall public interest. (Emphasis added)**[107]

Therefore, the Task Force will be evaluating potential legislative changes to the Act.

B. Argument — Net Metering Customers Have Access to the Default Morning/Evening TOU Rate Plan and the Anytime User Rate Plan Consistent with the Act, Historical Interpretation, and Rational Economic Price Signals. Renew's Recommended Study Is Undefined, Likely Duplicative, and Should Not Be Ordered.

When it comes to statutory interpretation, a court does not presume the legislature enacts meaningless provisions; rather, the court must presume every word, sentence or clause in a statute has effect, and the legislature did not insert superfluous language.[108] As explained in the Background section above, under subsection 3 of the Act, a retail electric supplier shall *inter alia*:

> (2) Offer to the customer-generator a tariff or contract that is identical in electrical energy rates, rate structure, and monthly charges to the contract or tariff **that the customer would be assigned if the customer were not an eligible customer-generator** but shall not charge the customer-generator any additional standby, capacity, interconnection, or other fee or charge that would not otherwise be charged if the customer were not an eligible customer-generator… **(Emphasis added)**

In contravention of the maxim to give every word in a statute effect, Renew attempts to focus on the offering of a tariff or contract that is identical to net metered customers and to treat the related language "that the customer would be assigned if the customer were not an eligible customer" as

[107] §386.885, RSMo. (2022).

[108] In the Matter of the Application of Liberty Utilities (Missouri Water) LLC d/b/a Liberty Utilities for Certificates of Convenience & Necessity Authorizing It to Install, Own, Acquire, Construct, Operate, Control, Manage, & Maintain A Water Sys. & Sewer Sys. in Bolivar, Polk Cnty., Missouri, WA-2020-0397, 2021 WL 3421151, at *4 (Mo. P.S.C. July 28, 2021), reconsideration denied, WA-2020-0397, 2021 WL 3836991 (Mo. P.S.C. Aug. 25, 2021) (citing *E & B Granite, Inc. v. Dir. of Revenue,* 331 S.W.3d 314, 317 (Mo. banc 2011), *quoting Kilbane v. Dir. of Revenue,* 544 S.W.2d 9, 11 (Mo. banc 1976) & *Wehrenberg, Inc. v. Dir. of Revenue*, 352 S.W.3d 366, 367 (Mo. banc 2011)).

superfluous. The interpretation giving every word in the statute effect is that the default contract or tariff otherwise offered to a non-net metered customer must be offered to a net metered customer, and the net metered customer cannot be charged any additional, standby or other fee that would not otherwise be charged to a non-net metered customer. As a matter of fact, in response to questions from Commissioner Kolkmeyer during opening statements for the issue, Renew's counsel quite clearly affirmed that this is the intent of the statute, saying, "… the statute is there to prevent solar fees from saying, All right, if you're going to take service under a net metering contract, you owe this much, you know, a, sort of a punitive fee for going solar."[109]

It is this interpretation giving every word in the statute effect that has apparently been relied upon by the Commission since 2008. Shortly after the Act became effective, in January 2008, the Commission approved changes to the Company's net metering tariff schedule, Schedule 1, Sheet No. 8, wherein net metered customers were **expressly not eligible** to participate in that optional TOU rate.[110] But in compliance with subsection 3 of the Act, net metered customers were eligible for the 1(M) regular rate that the net metered customers would otherwise be assigned if the customers were not net metered customers.[111] That eligibility limitation persists even in the currently effective "Grandfathered Option TOD (Time-of-Day) Rate Pilot" rate schedule attached to Company witness Michael Harding's direct testimony, stating: "Participation shall exclude customers with a net metering agreement."[112] Consequently, the Commission must have interpreted the Act, and specifically subsection 3, so that every word was given effect and to **not** require net metered customers to be eligible for all optional Residential rate plans from 2008 to present.

Notably, Renew commenced its discussion of the Net Metering Statute in its Initial Brief with

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[109] Transcript, p. 87, ll. 6 – 9.
[110] See Footnote 97 above.
[111] See Footnote 98 above.
[112] See Footnote 99 above.

the foundational principle: Missouri courts have long recognized that, "…the 'interpretation and construction of a statute by an agency charged with its administration is entitled to great weight'…[.]"[113] Yet, in the entire remainder of Renew's Initial Brief, Renew ignores, and certainly does not defer "great weight" to, the Commission's long-held (2008 to present) interpretation and administration of the Act — the Act does **not** require net metered customers to be eligible for all optional Residential rate plans. Instead, Renew seeks to focus on only select language of the Act to forge a new, contradictory interpretation of subsection 3 of the Act.

Renew's efforts to forge a new interpretation in this case are particularly perplexing given the OTR discussion about net metering and advanced TOU rate options in File No. ER-2019-0335, and Renew witness Owen's lack of any reply to Mr. Wills' direct testimony in File No. ER-2021-0240 as described in the Background section above. Tellingly, Renew's Initial Brief never attempts to explain why Renew chose this case to attempt to forge its new interpretation of the Act and/or did not discuss the issue at all in File No. ER-2021-0240. Even more perplexing, if not downright troubling, Renew attempts to disparage the Company by suggesting that the Company continuing to give the Commission's long-held interpretation of the Act great weight, and further explain the economically irrational outcomes that could occur if the netting across a billing period were followed for net metered customers, is wrong. Renew goes so far as to wrongly allege: "Given this reality, Mr. Wills' assertion that, [t]he Company has sincere interest in making these rates available to net metering customers,' belies the Company's true concern that it will experience reduced revenue and loss of control as more customers adopt and install DG technologies."[114] Such allegation is plainly false, and such disparagement is plainly unjustified.

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[113] EFIS Item No. 442, Renew Missouri's Initial Post-Hearing Brief, at p. 3, first sentence of section II(a) (*citing In re Laclede Gas Co.*, 417 S.W.3d 815, 819 (Mo. App. 2014) (*citing State ex rel. Office of Pub. Counsel and Mo. Indus. Energy Consumers v. Mo. Pub. Serv. Comm'n*, 331 S.W.3d 677, 684 (Mo. App. 2011)).
[114] Id., p. 6.

Similar to Mr. Wills' direct testimony from File No. ER-2021-0240 excerpted above, in Mr. Wills' surrebuttal testimony in this case, Mr. Wills explained that, when the Act is applied as written, the Act does not allow the billing of TOU rates in an economically rational manner.[115] More specifically, the Act requires that all energy consumed by a net metered customer from the grid during a billing period be netted with all energy produced and delivered to the grid by the net metered customer during the same billing period. This means that any kilowatt-hour ("kWh") of energy produced can net with any kWh of consumption — i.e., these kWh's must be economically valued equally irrespective of the time (peak versus off-peak, etc.) they occur. This dynamic is accordingly completely counter to the concept of TOU rates, which makes it clear that kWh have unique economic values during different time periods.[116]

Two attachments from the Company's response to a data request ("DR") referenced by Mr. Owen in his rebuttal testimony in this case, DR Renew-MO 2.2, were attached to Mr. Wills' surrebuttal testimony as Schedule SMW-S2. The first attachment to Schedule SMW-S2 walks through different TOU net metering examples, and the second attachment thereto are slides with a couple examples of netting over the entire billing period. Example #1 – April in the second attachment in Schedule SMW-S2 shows a net metering customer who is a net generator for the month (April), with excess generation in the intermediate time period and net consumption in the peak and the off-peak time periods. Under Example #1, netting across the billing month would allow peak usage to be offset by lower value excess generation, eliminating peak period price signal. Example #2 – August with Battery Arbitrage in the second attachment in Schedule SMW-S2 shows that under TOU rates with net metering netted over the entire billing period, battery storage could allow the customer to arbitrage the utility's power against the rate structure, while creating a less favorable

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[115] Exhibit 41, Surrebuttal Testimony of Steven Wills, p. 20.
[116] Id.

load profile. These examples show the types of economically irrational outcomes arising from the netting across a billing period construct.

The Company explained why it offers net metered customers the default Evening/Morning Saver TOU rate plan. The Company offers net metering in connection with the Evening/Morning Saver rate because the Evening/Morning Saver plan is a rate to which the Company would otherwise assign net metered customers, and as such, under the Company and implicitly the Commission's long-held assumed interpretation, the Company is legally obliged to offer it to net metered customers. Fortunately, the peak/off-peak pricing differentials in the Evening/Morning Savers rate plan are small enough that the irrational nature of the economic outcomes of offering the rate to net metered customers are not highly impactful. However, if a default rate with a wider differential were available in the future, the Company would have serious concerns about the appropriateness of that, due to the fact that the Company would need to offer it to net metered customers under the Act.

At page 8 of Renew's Initial Brief, Renew seems to suggest that the Commission can look beyond Missouri statutes for its authority, as long as its actions serve the public interest and/or further policy objectives,[117] which does not comport with Missouri Supreme Court precedent. The Court has actually recognized the Commission is "a creature of statute" which "can function only in accordance with its enabling statutes" and "[i]ts powers are limited to those conferred by statutes, either expressly or by clear implication as necessary to carry out the powers specifically granted."[118] The Commission cannot disregard the Act as Renew seems to suggest.

Remarkably, Renew further states:

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[117] EFIS Item No. 442, Renew Missouri's Initial Post-Hearing Brief, at p. 8, stating: "Aside from the question of whether Ameren is required to offer TOU rates to customer-generators, the Commission has the authority to determine that integrating net metered DG and TOU rates is in the public interest."

[118] Matter of Amendment of Commission's Rule Regarding Applications for Certificates of Convenience & Necessity, 618 S.W.3d 520, 524 (Mo. 2021), reh'g denied (Apr. 6, 2021) (*citing State ex rel. MoGas Pipeline, LLC v. Missouri Pub. Serv. Comm'n*, 366 S.W.3d 493, 496 (Mo. 2012)).

> On first glance, the concern Mr. Wills raises may seem fatal. However, other states have confronted the same challenge and charted a course forward that has allowed customer-generators to use time-varying rates to increase the savings from their DG systems and increase aggregate load shifting and demand reduction.[119]

There are two key pieces to unpack from that quote. First, Mr. Wills' referenced concern is for the economically irrational outcomes under the netting across a billing period construct, and that concern should indeed be fatal to imposing a netting across a billing period construct for advanced TOU rates. Second, Renew conveniently does not detail the specifics of the statutes in these other states who have charted a different course which presumably allow them to chart a different course whereas the Missouri Act does not.

As referenced in the surrebuttal testimony of OPC witness Dr. Geoff Marke, the newly formed Task Force will likely be addressing Renew's TOU and net metering concerns, and no additional study as proposed by Renew is needed.[120] Section 386.885, RSMo., establishes the "Task Force on Distributed Energy Resources and Net Metering." The Task Force is composed of 13 members, including two members of the senate, two members of the house of representatives, the chair of the Commission or their designee, a representative of investor-owned utilities, and a representative from the retail distributed energy resources industry.[121] The Task Force must compile a report to be delivered to the general assembly by no later than December 31, 2023, including a distributed energy resources study and potential legislation/changes to the Act that would promote the overall public interest.[122] Enigmatically, Renew's Initial Brief never mentions the Task Force or its report due by the end of this year. The Company posits that the Commission will likely be anxious to review the Task Force's report, and may thereby be better equipped to determine whether

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[119] EFIS Item No. 442, Renew Missouri's Initial Post-Hearing Brief, at p. 9,
[120] Exhibit 201, Surrebuttal Testimony of Geoff Marke, Ph.D., p. 28, l. 25 – p. 29, l. 2.
[121] §386.885.1, RSMo. (2022).
[122] §386.885.2, RSMo. (2022).

legislative changes may be pursued to avoid economically irrational outcomes using the netting across a billing period construct before ordering that net metered customers be offered optional rate plans.

At page 7 of Renew's Initial Brief, Renew recommends the Commission order Ameren Missouri to conduct a study on how to integrate distributed generation with the Company's Residential TOU rate plans, but is scant on details. Renew does not describe how the cost of conducting its requested study would be accounted for, nor if the Task Force's report will be duplicative at least in part of Renew's requested study. Renew does cite to Evergy's recent settlement term wherein Evergy agreed to conduct a study similarly requested by Renew. However, one utility's decision to conduct a study requested by Renew as part of a compromise settlement to resolve its general rate case is in no way binding on another utility. This further begs the question of whether Evergy's stipulated study, the Task Force's legislated study, and Renew's requested study to be performed by Ameren Missouri would be duplicative and unnecessary.

In summary, Renew's attack of a long-standing and reasonable interpretation of the Act whereunder all optional TOU rate options do not have to be offered to net metered customers should be thwarted, and Renew's request for yet another study without regard to the cost of such study should be denied.

III. <u>Reply to OPC's Initial Brief</u>

Under Issue 1, the Company replies to two points within OPC's Initial Brief — one a mere clarification and the other a correction. First, OPC stated:

> For stability while Ameren Missouri is still rolling out AMI meters for its residential customers, but to give those residential customers with AMI meters the greatest flexibility, Public Counsel recommends that the Commission make Ameren Missouri's Residential Evening/Morning Savers Plan the default for residential customers Ameren Missouri serves through an AMI meter; however, those customers should be able to elect to switch from Ameren Missouri's Residential

> Evening/Morning Savers Plan to any of Ameren Missouri's other residential rate plans, including its Anytime (flat) rate plan, **and they should be eligible to make that switch in less than six months**.[123]

To clarify, Residential customers with an AMI meter **are currently** able to select any of the Ameren Missouri's rate plans for which they are otherwise eligible in less than six months.[124] The Grandfathered Optional Time-of Day Rate Pilot, for example, is no longer offered to new enrollees.[125]

Second, OPC incorrectly characterizes the Company's proposed two-way rate-switching tracker as effectively "rate decoupling."[126] Actually, the requested tracker would be calculated by comparing what a customer's bill on the new rate will be to what their bill would have been on their legacy Anytime User rate plan. Since the calculation is based on application of two different rate plans to the same level of usage, the tracker is not in any way analogous to the concept of revenue decoupling as it exists in the industry.[127]

Regarding Issue 2, similar to Staff, OPC misunderstands how survivor curves are used in depreciation rates and estimating mass property asset retirements, which was addressed in reply to Staff's Initial Brief above and therefore will not be repeated here.

IV. Reply to Sierra Club's Initial Brief

The Sierra Club's Initial Brief reflects its fundamental dissatisfaction with the statutes and Commission regulations that govern both utility decisions to invest in resources, and the Commission's treatment of those investments for ratemaking purposes. In short, Sierra Club considers the Commission's current regulations inadequate, arguing that they do not protect

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[123] EFIS Item No. 440, OPC's Initial Brief, pp. 12 – 13.
[124] Exhibit 32, Direct Testimony of Michael Harding, Schedule MWH-D1, Sheet Nos. 54, 54.4 (Evening/Morning Saver), 54.7 (Smart Saver), 54.10 (Overnight Saver), & 54.13 (Ultimate Saver).
[125] Id., Sheet No. 54.3.
[126] EFIS Item No. 440, OPC's Initial Brief, p. 13.
[127] Exhibit 39, Direct Testimony of Steven Wills, p. 17, ll. 10 – 18.

customers. Yet Sierra Club fails to point to – and the record is devoid of any such evidence – a single instance where a utility in general, much less Ameren Missouri, has made imprudent investments against which the Commission was unable to protect customers.

Lacking any basis other than its own anti-coal-fired generation agenda to make such recommendations, Sierra Club then proceeds to ask the Commission to order two requirements, one of which its witness in this case did not even address or support at all:

- Order Ameren Missouri to seek a Certificate of Convenance and Necessity ("CNN") prior to installing Selective Catalytic Reduction ("SCR") or Flue Gas Desulfurization ("FGD") equipment at Labadie,[128] and
- Order Ameren Missouri to track environmental costs incurred that could be avoided by an early retirement of Labadie.

Both of these recommendations are inappropriate and unneeded. And both should be rejected.

A. Requiring Ameren Missouri to seek a CCN for permission to install SCRs or FGD equipment at Labadie.

The Sierra Club provides three reasons for this recommendation.

- First, it says that Ameren Missouri's actions at Rush Island were imprudent.
- Second, it points out that Labadie faces significant environmental compliance risks in the future.
- Third, it alleges that the existing CCN and IRP processes do not provide adequate scrutiny of the Company's plans.[129]

Rush Island Imprudence. First, the Sierra Club overstates its argument about Rush Island imprudence. It is true that the prudence of Ameren Missouri's actions related to NSR permits and

[128] Sierra Club provided no evidence in support of this recommendation but raised it for the first time in its Initial Brief.
[129] EFIS Item No. 446, Sierra Club's Initial Brief, p.7.

the resulting decrease in production as it operates as a MISO SSR have been raised as issues in this case. It is also true that Ameren Missouri supplied extensive evidence countering these arguments. The main proponent of the argument, the Staff, in fact did not actually base any claimed adjustment in this case on a claim of imprudence, suggesting only that it had affirmatively not concluded that Ameren Missouri's actions were prudent.[130] Regardless, the revenue requirement in this case has been settled in a stipulation and agreement that, under the Commission's applicable rules, is considered unanimous[131] (subject to its approval by the Commission). There is no basis in this case for finding the Company has acted imprudently, no party is asking that it do so, and thus there is no "imprudence" basis that can justify this Sierra Club recommendation. This makes Sierra Club's statements such as "That (IRP planning) process did not work out for Rush Island…"[132] and "…Ameren's failure to appropriately plan around Rush Island…",[133] which were made without citation to the record, irrelevant. Such unsupported and overblown assertions reflect nothing more than Sierra Club's opinion. Sierra Club is a party to this case and it did not object to the stipulation.[134] It knows the stipulation resolved all revenue requirement issues in this case for the purposes of this case and it was involved in the settlement discussions — all of which means the Sierra Club certainly knows that any Rush Island-related issues were resolved within the black box of the settlement, leaving whatever arguments Sierra Club or another party may or may not choose to make for resolution in a later case. To imply otherwise is to twist the truth.

Environmental Costs. The second argument used to justify this first recommendation are the

[130] See Staff Response to Motion to Strike, EFIS Item No. 231, p. 7 ("Staff witness Eubanks makes clear that she is not proposing her Rush Island adjustment on the grounds of prudence, [but] this does *not* equate to an affirmative endorsement of the prudence of Ameren Missouri's decision making.").
[131] 20 CSR 4240-2.115(1)(C).
[132] EFIS Item No. 446, Sierra Club's Initial Post-Hearing Brief, p. 1.
[133] Id, p. 6.
[134] File No. ER-2022-0337, Stipulation and Agreement, p.1, Footnote 1.

environmental challenges that Labadie (like most coal plants) will face in the future.[135] Ameren Missouri does not deny that real costs will be involved or that prudent resource planning requires the Company to consider these as part of the required Supply Side Resource Analysis for its upcoming 2023 IRP filing as well as future IRPs. As required by the Commission's regulations, that filing will look carefully at environmental regulations, both current and expected, including the costs of compliance with those regulations.[136] As Ameren Missouri witness Matt Michels testified, "In any case, the Company will include consideration of compliance with this [the Good Neighbor Rule] and other environmental regulations as part of its 2023 IRP analysis."[137] The Sierra Club is afforded several months to review and supply comments on the IRP.[138] If Ameren Missouri does not consider compliance methods and costs of compliance for these environmental regulations, Sierra Club has the right to claim a Deficiency[139] in the Company's planning. Interestingly, the Commission should take note that the Sierra Club's testimony and brief do not say that Ameren Missouri will not or cannot properly conduct this planning. Sierra Club does not allege any imprudence in the resource planning around Labadie. Sierra Club simply speculates that the Company might not comply with applicable planning rules in the future. This argument is only theoretical, likely because Sierra Club knows that the very issues Sierra Club raises are specifically called out and required to be addressed as part of the IRP process.

Inadequate CCN and IRP processes. Finally, Sierra Club argues that existing CCN regulations and the IRP processes are inadequate. Sierra Club provides no evidence that those processes are not working, especially when one considers the Commission’s authority in rate reviews

[135] EFIS Item No. 446, Sierra Club's Initial Post-Hearing Brief, p. 3.
[136] 20 CSR 4240-22.040.
[137] Exhibit 51, Rebuttal Testimony of Matt Michels, p. 3, l. 21-22.
[138] 20 CSR 4240-22.080(8).
[139] 20 CSR 4240-22.020(9).

to ensure that imprudent investments that harm customers are not reflected in the revenue requirement. In an IRP case, if Ameren Missouri did not meet the rules for planning adequately, say in evaluating the costs of certain environmental regulations, the Commission could find the Company's filing deficient and can order analysis to be redone. Sierra Club has made allegations of deficiencies in Ameren Missouri's IRP cases in the past, the Commission just hasn't agreed with the Sierra Club's arguments. Not winning an argument before the Commission does not mean the process is inadequate.

Certainly, rate reviews can and do function to protect customers from imprudent expenditures. If a utility makes an imprudent decision that harms its customers, the appropriate place to raise that concern is in the rate review where the utility seeks to include those costs as part of its revenue requirement. The potential for nonrecovery of a large investment is a huge incentive to avoid imprudent expenditures for any utility.

One final point on this request. Sierra Club requests relief that is not available to it under the law. Under the CCN rule, Ameren Missouri may be required to seek a CCN for installation of SCR or FGD equipment, depending on the cost. It is premature to know whether such a filing will be necessary, but if the costs are 10% or more of the Company's rate base, it must and it will request a CCN from the Commission, consistent with the rules.[140] What Sierra Club is asking the Commission to do is require Ameren Missouri to seek a CCN, regardless of the cost and regardless of whether the law requires it. Forcing Ameren Missouri to seek a CCN for such investments that do not reach the 10% threshold in the CCN rule would violate the Commission's regulation. If the Commission wanted to change that requirement to be, e.g., 5%, or if it wanted a CCN to be filed for all SCR or FGD installations, it could do so. However, it is required by law to follow the notice and comment

[140] 20 CSR 4240-20.045.

rulemaking procedures in Chapter 536, RSMo. if it desires to make such a change. It cannot simply change a regulation in a utility rate review.

Sierra Club's quotation to the Court of Appeals decision that upheld the Commission's 2018 revisions to its CCN rules does not authorize the Commission to simply ignore its own rule. In fact, Sierra Club misapplies the quote set forth in its brief. The question at issue in the cited case to which the quote applied was whether it was lawful for the Commission to *implement a rule* that applied to certain retrofit projects given that its prior rule had not reached that far. The Court of Appeals concluded that it did have the power to promulgate such a rule. Ameren Missouri agrees the Commission has the authority to further *revise its CCN regulations* — as noted, it could change them to use 5% increase as the trigger or it could require a CCN for all environmental upgrades. And it did just that in 2018, and the Court of Appeals affirmed that authority. But that does not mean the Commission can just add a requirement without changing its regulations at any time and without undergoing the required administrative process. The Sierra Club requested relief that cannot be granted in this case.

B. Requiring Ameren Missouri to track environmental compliance costs that could be avoided with early retirement

As justification for this recommendation, Sierra Club points to Ameren Missouri's planned capital investment at Labadie over the next five years and argues that justifies its recommendation to track expenditures that could be avoided if Labadie is retired early.[141] Here, again, the Sierra Club does not allege imprudence or wrongdoing on the part of Ameren Missouri. Instead, it wants to require Ameren Missouri to track certain costs to assist it in building its potential future prudence arguments. As pointed out in the Company's initial brief, all of this information can be gained through discovery. Additionally, as Company witness Michels pointed out in his rebuttal, there is

[141] EFIS Item No. 446, Sierra Club's Initial Post-Hearing Brief, p. 5.

already information available to it in the IRP. "[In the IRP,] The Company develops explicit capital investment assumptions for each retirement date contemplated. A comparison of the assumed investments for two different retirement dates would thus indicate which investments are needed for the later of the two retirement dates that could be avoided for retirement at the earlier of the two dates."[142] Much of what the Sierra Club requests is already or will be available to it for use in future rate reviews. As a party to future rate reviews, Sierra Club can conduct discovery on this question and to make disallowance recommendations as it feels is appropriate. Adding further administrative burdens not required by the Commission's rules — an additional tracking requirement — would be of no real value and is not needed to address any actual harm. There is no need to identify these costs ahead of an actual rate review filing. This recommendation should be rejected.

[142] Exhibit 51, Rebuttal Testimony of Matt Michels, p. 4, ll. 6-12.

Respectfully submitted,

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Certificate of Service

I hereby certify that a true and correct copy of the foregoing was served electronically on this 15th day of May, 2023, to the parties of record as set out on the official Service List maintained by the Data Center of the Missouri Public Service Commission for this case.

/s/ ***Wendy K. Tatro***
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