Exhibit No.:	
Issue(s):	Policy Considerations
Witness:	Steven Wills
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2024-0319
Date Testimony Prepared:	January 17, 2025

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2024-0319

REBUTTAL TESTIMONY

OF

STEVEN WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
January 2025

TABLE OF CONTENTS

REBUTTAL TESTIMONY

OF

STEVEN WILLS

FILE NO. ER-2024-0319

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Steven Wills. My business address is One Ameren Plaza, 1901 Chouteau Ave., St. Louis, Missouri.

Q. Are you the same Steven Wills that submitted direct testimony in this case?

A. Yes, I am.

Q. To what testimony or issues are you responding?

A. My rebuttal testimony responds to a variety of issues, parties, and witnesses' direct testimonies, as listed below:

- High Prairie revenue requirement adjustments sponsored by Staff witness Claire Eubanks, Missouri Energy Consumer's Group ("MECG") witness Greg Meyer, and Office of Public Counsel ("OPC") witness Manzell Payne.
- Class Cost of Service and revenue allocation proposal sponsored by Staff witness Sarah Lange.
- Net metering and Time of Use ("TOU") rate proposals sponsored by Renew Missouri witness James Owen and Staff witness Sarah Lange.
- Advanced Metering Infrastructure ("AMI") opt out proposal sponsored by OPC witness Dr. Geoff Marke.

- Renewable Solutions Program ("RSP") issues discussed by Staff witness Paul Amenthor and Renew Missouri witness James Owen.
- Green Button tariff proposal sponsored by Renew Missouri witness Michael Murray.
- TOU communications recommendations raised by OPC witness Dr. Marke.
- Residential battery storage pilot recommendation made by Renew Missouri witness James Owen.
- Discussion of the Energy Community Tax Bonus in the direct testimony of Consumer's Council of Missouri ("CCM") witness Caroline Palmer.

II. UNWARRANTED HIGH PRAIRIE REDUCTIONS TO REVENUE REQUIREMENT SHOULD BE REJECTED

Q. What parties sponsor proposed adjustments to reduce the revenue requirement in this case related to High Prairie Energy Center operations?

A. Staff, OPC, and MECG witnesses Eubanks, Payne, and Meyer, respectively, each propose some form of revenue requirement adjustments and other similar proposals related primarily to curtailment of wind generation operations at High Prairie that are being undertaken in order to ensure compliance with the Company's Incidental Take Permit related to endangered bat species in the area around the facility. These curtailments, not unlike dispatch limitations imposed by environmental regulations applicable to fossil units, have been prudently undertaken in compliance with the Endangered Species Act and to preserve the Company's longer term ability to maximize facility production, as discussed by Company witness Arora's rebuttal testimony.

Q. Do you agree that any or all of these revenue requirement adjustments are appropriate in this case?

A. No. They are all inappropriate for policy and factual reasons detailed in the rebuttal testimonies of Company witnesses Ajay Arora and John Reed. I fully agree with the opinions and conclusions of both witnesses Arora and Reed that the costs associated with the facility are prudently incurred based on what was known at the time the decision to invest in the facility was made, continue to be prudently incurred given the Company's ongoing prudent operation of the facility, and that the Company should be entitled to reflect the costs associated with the operation of the facilities in customer rates and to earn a reasonable return on its investment in it.

Q. Do you have any additional perspective to offer beyond that provided by witnesses Arora and Reed?

A. Yes, I would share one additional point that I am advised by counsel makes these proposals legally questionable at best. Further, I will discuss key considerations the Commission should contemplate before adopting any adjustments, should it be persuaded, in spite of the policy considerations presented in the Company's rebuttal testimony, that any adjustment should be made.

Q. Why do you claim the adjustments are "legally questionable" at best?

A. The Company's attorneys will address this point in other filings to be made in this docket. My focus is on the plain language of the Renewable Energy Standard ("RES") statute[1] in Missouri, which provides as follows:

> The commission . . . shall make whatever rules are necessary to enforce the renewable energy standard. Such rules *shall* include . . . Provisions for recovery outside of the context of a general rate case of *prudently incurred* costs and the

[1] RsMO 393.1030

> pass-through of benefits to customers of any savings *achieved* by an electrical corporation in meeting the requirements of this section.[2]

This provision of Missouri law expressly codifies the fact that the standard for recovery of RES compliance costs is prudence, and therefore by extension that such costs are not subject to other standards such as production guarantees or some kind of used and useful condition, even if either of those concepts were otherwise reasonable regulatory policy, which they are not as discussed by witnesses Arora and Reed. And this provision of law makes perfect sense. The RES law itself imposes a new obligation on utilities to provide a specific kind of energy – renewable energy – leading them to make specific types of investments at a significant scale (in renewable energy resources like High Prairie) and which would otherwise be at the discretion of utility management to undertake. In exchange for the obligation the RES imposes on the Company to comply with the state policy considerations reflected in the RES statute, the utility is given assurance that it will not be taking on extraordinary risks as a part of that investment (i.e., such as guaranteeing production levels). It simply has to undertake prudent decision making and the costs will be recoverable. Parties' attempts to thwart that recovery should be rejected.

The Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") tariff, which I am advised also has the force and effect of law and was approved by the Commission, specifically dictates that the RES compliance costs "consist of prudently incurred costs, both capital and expense," directly related to RES compliance and dictates that those costs be recovered. See Ameren Missouri Mo.P.S.C. Schedule 6, Sheet Nos. 93 to 93.3.

[2] Id. (emphasis added).

Q. Has any party challenged the prudence of the Company's investment in the High Prairie Energy Center or of how the Company is operating it?

A. No. And as to the decision to acquire the facility, most of the parties proposing adjustments cannot make such a claim. This is due to their express agreement that the decision to acquire High Prairie was prudent, which is evident from the Stipulation and Agreement in the Certificate of Convenience and Necessity ("CCN") case in which the Commission authorized the Company to acquire the High Prairie facility, File No. EA-2018-0202. That Stipulation and Agreement memorialized the parties' agreement that the decision to acquire the facility – with the signatories having full knowledge of the protected bat species that lived in the area and the potential that their presence could impact production – was prudent, as more fully discussed in witness Arora's testimony.

Any attempt to impute revenues (including Production Tax Credits ("PTCs")) through a production guarantee or used and useful standard, or disallow any amount of rate base in the facility, without proper evidence and a resulting finding of imprudence is a de facto disallowance of prudently incurred RES compliance costs, which I believe contravenes the plain language of the RES statute that imposes on the Commission the requirement that it "[p]rovi[de] for recovery outside of the context of a general rate case of prudently incurred costs and the pass-through of benefits to customers of any savings achieved by and electrical corporation in meeting the requirements of this section". Or said another way, such imputation would pass through savings that were not *achieved*, as the law requires, but rather savings that were merely assumed and imputed. Simply put, the proposals of Staff, OPC, and MECG go far beyond ensuring recovery of prudently incurred costs offset only with the return of *achieved* benefits, which is part of the bargain contained in the RES statute's imposition of obligations on utilities.

Q. Is it clear that the costs associated with High Prairie are RES compliance costs governed by the RES statute and its cost recovery provisions?

A. Yes. The costs of the facility have been included in the Company's RESRAM since the time the facility went into service[3], and further have been included in the Company's annual RES compliance filings as a source of compliance Renewable Energy Credits consistently since its acquisition[4]. Indeed, as Mr. Arora discusses, Staff itself found that the facility was needed for RES compliance purposes.

Q. What other issues related to the parties' proposed adjustments related to High Prairie do you wish to discuss.

A. The Commission should not approve any of the adjustments at all, but if it were to do so, any adjustment should be factually and conceptually sound. None of the proposed adjustments meet that standard.

Q. Why not?

A. To understand why not, one must understand the interaction of the RESRAM tariff mechanism (a mechanism required by the statute as discussed above) with the base rates to be set in this case.

Q. Please describe generally how cost recovery associated with RES assets is achieved by Ameren Missouri?

A. In a rate case like this one, a test year (including true up items) snapshot of the revenue requirement (including both RES compliance costs and benefits) associated with such

---

[3] See, for example, page 4 of the testimony of Raysene Logan in the Company's most recent RESRAM rate filing, File No. ER-2025-0119, which documents the inclusion of capital costs associated with High Prairie related investments in the costs included in the Company's filed RESRAM rate.

[4] See, for example, page 5 of the Company's Renewable Energy Standard Compliance Plan 2024-2026, File No. EO-2024-0231.

RES compliance assets is included in the overall revenue requirement on which base rates are established. That is to say, base rates are designed to produce revenues that cover all of the Company's costs including costs of the RES-related investments based on trued up test year cost, benefit, and investment levels. The RESRAM tariff is based on the presumption that those costs *are* recovered by the Company through base rates. The test year level of net RES compliance costs reflected in base rates becomes the "base amount" for the RESRAM tariff. The RESRAM tariff tracks the difference between actual RES compliance costs and benefits that occur when rates are in effect and that "base amount" upon which those rates were established. That is to say, the RESRAM tracks *changes* in costs and benefits from the level reflected in base rates in order to ensure 100% of actual RES compliance costs are recovered from and 100% of RES compliance benefits are returned to customers.

For a simple illustration, let's assume that the total revenue requirement in a utility rate case is $1,000, and its RES compliance costs (net of RES benefits) are a subset of that $1,000 that totals $100. In this example, rates will be set in a manner that is designed to collect $1,000 (the total revenue requirement) from customers annually, with $100 of that $1,000 related to the utility's RES activities (this $100 subset of costs related to RES compliance becomes the "base amount" for the RESRAM). Now, presume that rates take effect from that rate case, and RES compliance costs increase to $110. Further assume, for simplicity, that the utility's other costs do not change from the test year, resulting in a revenue requirement during the period where rates are in effect of $1,010 (the original $1,000 revenue requirement plus the $10 increase in net RES costs). The utility will be operating under static base rates that only produce $100 of revenue *associated with RES compliance activities*. The RESRAM tariff would take the difference between the $110 of net RES costs incurred and the $100 of net RES costs covered by actual base rate revenues (the base amount) and allow the Company to recover that $10, ensuring what amounts to essentially full recovery of its net RES compliance costs. Again, assuming that no other costs changed relative to the revenue requirement used to establish base rates, the utility in question would have a reasonable opportunity to cover all of its costs and earn a return on its investments, because the RES-related cost increase that occurred after the rate case would be captured by the RESRAM. This hypothetical scenario is illustrated below in Table 1.

Table 1 – Simplified Illustration of Interaction of Base Rates and RESRAM in Scenario of Increasing RES Costs and Constant Non-RES Costs

Description	Rate Case Test Year	1st Year After Rate Case Takes Effect	Notes
RES Compliance Costs Net of Achieved Benefits	$100	$110	RES costs increase relative to test year
Non-RES Revenue Requirement	$900	$900	No Increase in other costs relative to test year
Total Revenue Requirement	$1,000	$1,010	Total revenue required is $10 higher than test year due to increase in net RES costs
RESRAM Base Amount	$100	$100	Equals the amount of RES costs reflected in total revenue requirement underlying base rates
Base Rate Revenues	$1,000	$1,000	Rates are designed to produce revenues that cover test year revenue requirement
RESRAM Recovery of Change in Actual Net RES Costs	$0	$10	RESRAM recovers changes from base rate recovery of net RES costs
Total Revenues	$1,000	$1,010	Total revenues equal base rate revenues plus RESRAM recoveries
Revenue Available to Meet non-RES Revenue Requirement	$900	$900	After covering RES costs, remaining revenues meet the remaining revenue requirement - utility earnings not impacted by increasing RES costs as a result of the protection provided by the RESRAM

This illustration is designed to demonstrate that the RESRAM is an effective mechanism for ensuring that utility earnings are neither positively nor negatively impacted by changes in prudently incurred RES costs and benefits from the levels used to establish base rates, *assuming the RESRAM base amount is in sync with the amount of RES costs and benefits reflected in the revenue requirement that underlies base rates*.

Q. What concerns do you have about Staff's High Prairie related adjustment to the revenue requirement in this case?

A. As I understand witness Eubanks' testimony, Staff proposes to impute RES benefits into the revenue requirement used to set base rates in this case (i.e., reflect benefits of higher levels of Off-System Sales, Renewable Energy Credit ("REC") and PTC benefits than are expected to really exist, in an attempt to "hold customers harmless" for lower production associated with curtailment of the facility during bat season), which lowers the revenue requirement below the level required for the Company to fully recover its costs and earn a return on its investments. Staff's intent appears to be to make the Company bear the negative financial impact of lower production from the facility when curtailed, which reduces these benefit sources that otherwise act as a reduction to the overall revenue requirement for the benefit of customers. However, because Staff reduces the revenue requirement used to set base rates but does not appear to adjust the RESRAM base amount to match the level of RES costs reflected in its revenue requirement, the Company would fail to recover its revenue requirement *even if production is not curtailed at all* when rates become effective. That is to say if, for example, the Company's mitigation efforts described in Mr. Arora's rebuttal testimony were completely effective and High Prairie electricity production was not impacted at all by curtailments, the increased benefits would flow back to customers through the RESRAM, rather than making the Company whole for the imputed revenues Staff proposes in this case.

Q. Please explain why that is the case.

A. Staff proposes to impute off-system sales, PTC, and REC benefits into the total revenue requirement in this case as if High Prairie is not curtailed. However, the production profile Staff uses to model its revenue requirement in this case does include curtailment, and Staff witness Amenthor indicates that it is that profile that is used to value the Production Tax Credits that are reflected in the calculation of the RESRAM base amount. Therefore, there is a mismatch between the amount of PTCs (and presumably off-system sales and RECs although witness Amenthor's testimony appears to be silent to those items) in the RESRAM base versus the general revenue requirement. The upshot of this is that using Staff's proposed approach customers would get the benefit of imputed revenues via lower base rates as if there is no curtailment in base rates, and then would get those benefits *again* through the RESRAM if higher, uncurtailed production should manifest once rates are in effect. This would double count those benefit streams, lowering rates for customers but depriving the Company of an opportunity to recover its costs and earn a return on its investment. It is this mismatch between the treatment of base rates and the RESRAM base amount that must be avoided to prevent the potential double counting that Staff's adjustment creates. To put numbers to it, Staff witness Eubanks calculates a $27.1 million base revenue requirement reduction, premised on the assumption that significant curtailments will occur during the period base rates are in effect, and which will reduce base rates by that amount annually until base rates are reset. But if curtailment does not occur and production is higher than assumed for purposes of Ms. Eubanks' calculation, every dollar of energy, PTC, and REC value from the higher production will flow-back dollar for dollar to customers through the RESRAM and the Company will not be made whole.

Q. What issues do you have with the mechanics of the proposed adjustment sponsored by MECG witness Meyer?

A. Witness Meyer takes a different approach, and it does not result in the same form of potential double counting as Staff's approach. However, Meyer proposes to make a future imputation within the RESRAM mechanism itself. This again implicates the point that I raised earlier, that this in fact runs afoul of the plain language of the RES statute that requires all prudently incurred costs and *achieved* benefits to flow through the RESRAM. In addition to that, though, there is an additional flaw with witness Meyer's adjustment, in that he takes a blunt approach that amounts to a full production guarantee for <u>any and all</u> sources of production variation in his attempt to insulate customers from bat-related curtailment impacts. What I mean by this is, witness Meyer attempts to guarantee a specific High Prairie capacity factor through the RESRAM. That means that a certain amount of production would be reflected in the RESRAM *regardless* of what factors might influence the actual level of production. That means that the Company's earnings will be negatively impacted under MECG's proposal if production is lower than anticipated simply because the wind does not blow as much as expected some year – even if there is no bat-related curtailment whatsoever at High Prairie. This would also be true for any other source of lower production that may manifest. This is a standard that I am not aware of having been imposed on any generation resource of the Company by the Commission ever without a finding of imprudence related to that generation source, and I cannot fathom how it can be considered a reasonable proposal. All generation resources are subject to variation in production, and experience unexpected outages, sometimes significant and lengthy outages, and never have I seen a Commission imposed production guarantee where the Company would have to absorb the impact of lower production that occurred for any reason, where the Company's prudence had nothing to do with the production impacts. MECG's unprecedented production guarantee proposal should be rejected out of hand.

Q. Are there any other issues raised by MECG witness Meyer that you wish to address?

A. Yes. Witness Meyer's direct testimony suggests that off-system sales associated with High Prairie flow through the Company's Fuel Adjustment Clause ("FAC") mechanism, and REC and PTC benefits flow through the RESRAM. This is contrary to the both the Company's FAC and RESRAM tariffs. The FAC specifically excludes "amounts for Renewable Energy Standard compliance" (See Tariff Sheet 71.1). The RESRAM tariff mandates that it shall include "the pass-through of benefits to the extent those benefits are not passed through to customers" in the FAC. The annual RESRAM adjustments include the REC and PTC benefits (as well as energy revenues from RES compliance assets).[5] The FAC does not include energy revenues from any of our RES compliance generation, including High Prairie. Witness Meyer's references to FAC impacts arising from the High Prairie revenue requirement are therefore incorrect and should be disregarded.

Q. Beyond policy-based disagreement with the concept, what issue do you take with the mechanics of the OPC's High Prairie related adjustment?

A. OPC witness Payne attempts to calculate a rate base disallowance based on a percentage of hours during which High Prairie production is curtailed. However, his calculation

[5] When the RESRAM was first implemented, energy revenues remained in the FAC (with a provision that did not share 5% of higher revenues with the Company, i.e., customers received full benefit of all RES compliance asset energy revenues. This was changed in File No. ER-2022-0337, as agreed upon by the settling parties, so that all revenue streams, including energy revenues, are included in the RESRAM.

is overly simplistic and overstates the likely impact of curtailment on total production. Witness Payne simply takes the number of hours subject to curtailment and divides that number by the total hours in the year. This calculation completely fails to recognize that, from a wind resource perspective, not all hours are created equal. In fact, the winter months where *no curtailment is taking place at all* related to mitigation of wildlife impacts are generally the months with the most wind and best production of the whole year. In contrast, the summer months that protected species are most active are characterized by lower wind levels that should naturally experience lower levels of production. To put "wind resource" in more layperson's terms – the wind blows a lot harder and for longer periods during the winter than it does on hot and muggy summer nights. By treating each hour equally, witness Payne is overstating the impact of curtailment on production, and thereby proposes an unreasonably high percent disallowance.

Q. Can you provide any data that puts the issue you just identified into perspective? How different is the typical wind resource capability seasonally?

A. Yes. The seasonal difference in wind resource availability is striking. This is immediately evident through a simple review of the production profile that quantifies expected resource output when using a 6.9 meter per second cut in speed. Use of a minimum cut in speed of 6.9 meters per second was what the Company (and other parties to the CCN case where the Commission approved High Prairie) understood to be the worst case production level, which would result in full avoidance of protected bat take, and which was central to the Company's and other parties' understanding of the potential effects of mitigation that might be required when the facility was in operation.[6] In fact, several of the parties' positions in this case seek to anchor on that 6.9 meter per second production level as the amount of production that they seek

[6] Mr. Arora's rebuttal testimony discusses the understanding that use of a minimum cut-in speed of 6.9 meters per second would provide full avoidance in his rebuttal testimony.

to have the Company implicitly or explicitly "guarantee". Table 2 below shows the number of hours by month where there is no expected production from High Prairie based on a minimum cut-in speed of 6.9 meters per second.

Table 2 – High Prairie Zero Production Hours by Month at 6.9 M/S Cut In

Month	Hours of Zero Production	Total Hours in Month	Percent of Hours with no Production
Jan	13	744	2%
Feb	12	672	2%
Mar	3	744	0%
Apr	67	720	9%
May	102	744	14%
Jun	82	720	11%
Jul	138	744	19%
Aug	142	744	19%
Sep	93	720	13%
Oct	94	744	13%
Nov	10	720	1%
Dec	9	744	1%
Annual	765	8760	9%

It should be immediately striking that Table 2 reveals that the winter season months of November through March, which are not subject to bat-related curtailment at all, typically have between just zero and two percent of hours with no expected production – essentially the wind is producing energy almost constantly during these times of year. Yet in the months of the seasons subject to potential curtailment (April to October), zero production hours range from 9% to 19% of *all* hours. There is obviously a strong non-bat season bias to the production at the facility, and bat-related curtailments do not impact those high production periods *at all*. There is simply no credible argument that taking a simple average of the total hours of the year that may be subject to curtailment and applying it to annual production (that includes higher levels of production outside the bat season) is a fair representation of the actual impact of the bat curtailment on generation levels and the financial impacts that arise from that generation.

Witness Payne's overly simplistic calculation cannot be relied upon as the basis of any rate base disallowance or adjustment to the revenue requirement associated with bat-related curtailment.

III. ADOPTION OF STAFF'S CLASS COST OF SERVICE RESULTS AND/OR REVENUE ALLOCATION PROPOSAL WOULD PUSH THE COMPANY'S RATES AWAY FROM INDUSTRY NORMS

Q. What is the significance of the Class Cost of Service ("CCOSS") and revenue allocation portion of the case?

A. While the determination of the revenue requirement establishes how much rates will increase as a result of this case, the CCOSS and revenue allocation portions determine what customer classes will pay what proportion of the increase. Decisions on these issues are impactful to individual customers and customer classes. Company witnesses Tom Hickman, Nick Phillips, and Nick Bowden each address certain elements of these issues.

Q. What perspective will you share on these issues?

A. I will attempt to put Staff's CCOSS results and revenue allocation into some broader perspective, and in so doing will reinforce conclusions of witnesses Hickman and Phillips regarding the unreasonableness of Staff's study results and ensuing recommendations in that broader industry context.

Q. Please provide that broader industry context.

A. The Edison Electric Institute ("EEI"), an industry organization made up of investor-owned electric utilities ("IOUs"), conducts rate surveys and compiles the results for industry benchmarking analysis. The last full survey report the Company received from EEI[7] demonstrates the following relationship of the Company's residential, commercial, and industrial rates relative to national average rates of other IOUs.[8]

Table 3 – Comparison of Ameren Missouri Class Rates to National Averages

(cent per kWh average realized rate)	Residential	Commercial	Industrial	Total Retail
National Average	16.54	13.28	8.14	13.45
Ameren Missouri per EEI	11.78	8.93	7.28	9.96
Ameren Missouri versus National Average per EEI	-29%	-33%	-11%	-26%

Q. What observations do you have regarding the comparison of the Company's rates to national averages?

A. First, it is noteworthy that the Company's rates are well below – more than 25% below, in fact – national average rates in total. That is a good thing for Missouri in terms of affordability of electric utility service.

Next, it is also noteworthy that there is a significant disparity in the relative relationships of our various class rates to the national averages. I would observe that, relatively speaking, the Company's industrial rates are much closer to the national average than are our residential or commercial rates. From a relative standpoint (again, on an absolute level the Company is below average across the board), industrial rates are high when put in the national context. This is important to think carefully about, given the important role that the affordability of industrial electric rates plays in driving economic activity in the region, which of course benefits the region in a number of significant ways.

[7] The latest such report received by the Company is based on analysis of the rates in effect for the 12-month period ended December 2023. I have observed this EEI rate comparison data for many years in my professional role, and the results for this period are generally consistent with the relative comparison of our rates to national averages over time. In my opinion, this snapshot of rates can be considered generally representative of the ongoing relationship of the Company's rates to national averages.

[8] Typical Bills and Average Rates Report – Winter 2024, EEI

Q. How does this context provide insight about Staff's CCOSS and revenue allocation proposal?

A. Staff's CCOSS (and resulting revenue allocation proposal) have significant conceptual and methodological flaws. Those flaws are addressed directly by Company witnesses Hickman and Phillips. I will discuss the consequences of those flaws. At a high level, the context I just provided about the Company's comparative rates demonstrates that the results of the study are far outside of the mainstream.

Q. Please elaborate.

A. I calculated how the Company's rates would compare to national averages by holding all other things constant, and simply applying two sets of rate increases to the Company rates used in the comparison. The first comparison I made was based on the class increases implied by Staff's CCOSS as necessary to achieve an equal rate of return from all classes. The second comparison was based on the class increases recommended by Staff for implementation in this case as a result of its revenue allocation proposal. I will provide the detailed results in a moment, but I can say as a high-level conclusion, the Staff's CCOSS and revenue allocation recommendations would both impose a greater increase on industrial rates than on commercial or residential rates. That increase would be on top of the already relatively higher industrial rates that are reflected in the EEI benchmarking analysis. Suffice it to say, the class shifts recommended by Staff go the wrong way with respect to aligning the Company's relative rates with industry norms.

Q. How did you calculate the residential, commercial, and industrial rate increases that would arise from application of Staff's CCOSS and revenue allocation proposals?

A. I started by making calculations that are critical to making the rates associated with the Company's rate classes comparable to the definitions of commercial and industrial rates contained in the EEI report. It is critical to recognize that the Company's tariff rate classes (except in the case of residential) do not align with those EEI definitions. That is to say, it is a meaningless "apples to oranges" comparison to try to compare, for example, the Company's Large Primary Service rates to the EEI definition of industrial rates on a standalone basis. The Company has both commercial and industrial customers within *each* of its non-residential rate classes, including rates 2M – Small General Service, 3M – Large General Service, 4M – Small Primary Service, and 11M – Large Primary Service, and the impact of increases on each of those tariffed classes must be considered for both the commercial and industrial rate comparisons. Again, I would emphasize that, without adjustment, no meaningful comparison can be directly made between our rate classes and the commercial and industrial rate reported by EEI.

However, the Company does have the data to decompose the load in the various rate classes (2M, 3M, 4M, and 11M) into its commercial and industrial components. So, by taking a load weighted average of the increases applicable to each rate class associated with Staff's CCOSS and revenue allocation proposal – weighted by the proportion of the total commercial or industrial load served by the Company in each of those rate classes[9] – one can construct a

[9] No such weighted averaging need to be done for the residential class, since the rate (1M tariff) class and revenue class (residential, as used by EEI) definitions align.

commercial and industrial rate increase that would arise from application of Staff's CCOSS and revenue allocation proposal.

Q. Please provide a rate comparison of the rates that would result from applying the weighted average implied residential, commercial, and industrial rate increases to the Ameren Missouri baseline rates in the EEI analysis and comment on the results.

A. Table 4 below shows the residential, commercial, and industrial class rates that would result from this process based on the rate class increases that would be required to achieve an equal rate of return from the classes as reflected in the Staff's CCOSS. Table 5 presents the results of the same exercise using Staff's revenue allocation proposal in this case.

Table 4 – Ameren Missouri Class Rates Versus National Averages After Applying Staff CCOSS Results

(cent per kWh average realized rate)	Residential	Commercial	Industrial	Total Retail
National Average	16.54	13.28	8.14	13.45
Ameren Missouri per EEI as Adjusted for Staff CCOSS	13.01	10.25	8.53	11.36
Ameren Missouri Adj. versus National Average per EEI	-21%	-23%	5%	-16%

Table 5 – Ameren Missouri Class Rates Versus National Averages After Applying Staff Revenue Allocation Proposal

(cent per kWh average realized rate)	Residential	Commercial	Industrial	Total Retail
National Average	16.54	13.28	8.14	13.45
Ameren Missouri per EEI as Adjust for Staff revenue allocation	13.43	10.21	8.36	11.36
Ameren Missouri Adj versus National Average per EEI	-19%	-23%	3%	-16%

What this analysis demonstrates is that Staff's CCOSS methodology and revenue allocation recommendations push the Company's class rates further out of relative alignment than they already are as compared to national average class rates. It is quite noteworthy that this simplified analysis suggests that the Company's industrial rates would be above the national average. Keep in mind, this is a "holding all else constant" analysis, and other factors ultimately will impact whether that is the case. But given that overall retail rates remain 16% below the national average, it is troubling nonetheless that Staff would push industrial rates to a level that could potentially push them above the national average. This would certainly not be a good thing for Missouri's competitive economics in terms of attracting business and economic activity to the region.

Q. How would you interpret this analysis in the context of evaluating Staff's CCOSS and revenue allocation proposal?

A. I certainly do not claim that this analysis proves that any individual criticism of Staff's study is the cause of this result. I leave those criticisms to Messrs. Phillips and Hickman. However, there are really only two reasonable possibilities that I can come up with that explain the phenomenon that I just described, and those are:

- Staff's allocation methods are outside of the mainstream methods that are used typically in the industry, driving a divergence of results from industry benchmarks; and
- Other states have made policy decisions, above and beyond any such decisions Missouri has made, that influence the utilities' rates in those jurisdictions, to deliberately subsidize industrial customers through electric rates.

Theoretically it would also be possible that just underlying differences in the cost structure of the Company versus industry norms could cause this, but in my professional opinion, that is highly unlikely to be the most significant driver here. I believe the largest contributor, by far, is the unorthodox and, quite frankly, flawed, methods of cost allocation sponsored by Staff. And to the extent that the second reason comes into play – that is to say, that other states are seeking to keep industrial rates competitive – that is useful context that may help inform the Commission, along with the many other important considerations related to rate design, in deciding whether to follow Staff's results – especially when there is evidence that those results arise from questionable methodologies. Regardless of the reason for higher relative industrial rates in our service territory, the effect of those higher rates on our competitive economic position will be the same.

In summary, I think this context is a useful perspective to help illustrate to the Commission that Staff's results are out of the mainstream and should not be adopted for purposes of setting rates in this proceeding.

IV. ADVANCED TIME OF USE RATES ARE NOT COMPATIBLE WITH MISSOURI'S NET METERING FRAMEWORK

Q. Please describe the proposals made by other parties in their direct testimony that would expand net metering availability to the Company's advanced TOU rate options?

A. Both Staff and Renew Missouri make such proposals. Renew Missouri witness Owen recommends that net metered customers be allowed to adopt advanced TOU rates, and that the customer be credited at the applicable TOU rate for any exports that occur within a given TOU period. Staff recommends that the TOU rates be reconfigured such that a base rate is applicable to all hours and the higher priced periods be structured as a rate adder that also applies to kilowatt hours consumed during that period and the lower priced periods be structured with an incremental credit applicable to kilowatt hours consumed during that period. However, neither of Staff's nor Renew's TOU net metering paradigms result in economically rational price signals to customers. This phenomenon was discussed in more detail in the TOU net metering report attached to my direct testimony in this case. Under both Staff and Renew Missouri paradigms, as I understand them,[10] customers may actually end up with negative retail bills if they over-generate during peak (higher priced) periods, creating credits at high retail rates, and consume during off-peak (lower priced) periods, creating off-peak charges that are lower than the peak credit amounts. This would unquestionably result in significant subsidization of net metered customers from other non-net metered customers (well above and beyond the subsidy that generally exists with net metering applied to non-TOU rates). It should go without saying that all customers should be contributing at least *some amount of revenue* to cover the large amount of fixed costs on the system. Retail rates reflect those fixed and embedded costs of the system that are and should be shared by all customers that use the system. That is another way of saying that retail rates are not equal to, nor are they intended to be equal to, the marginal cost of energy or capacity that may be avoided when a generating customer exports power to the grid. Providing retail credits at these higher peak and intermediate rates will almost certainly exceed the avoided marginal costs of energy and capacity that would result from customer-generators' exports to the grid. In such a circumstance, the generating customer would contribute absolutely *nothing* to cover the costs of the fixed network of poles, wires, transformers, and other devices that are *essential to all customers – including customer generators*. This economic outcome cannot be considered reasonable or fair to all customers and should be avoided.

[10] The specific mechanics of Staff's proposal are not entirely clear to me, and pending receipt of a response to a Data Request issued to Staff on that topic, my understanding may be further refined.

Q. Does Staff acknowledge that its proposal is not economically rational?

A. I believe so. Witness Sarah Lange describes her TOU net metering proposal as not being reflective of cost causation and revenue responsibility.[11] I interpret this to be acknowledgment that even Staff does not believe that its proposal is good policy, but rather an option it is presenting to the Commission given the interest that has been expressed in the past in making TOU rates available to net metered customers. I fully agree with witness Lange that Staff's proposal is inconsistent with cost causation and revenue responsibility and strongly believe that such a proposal should not be adopted.

Q. Are there any other paradigms that could be considered if the Commission is convinced that TOU rates should be available to net metered customers?

A. Yes. The Commission recently approved an Evergy proposal that makes TOU rates available to net metered customers, and I believe that it is a reasonable economic paradigm under which to provide TOU rate options for net metered customers. I have hesitated to propose this approach in the past due to the complexity of its interpretation in light of specific provisions of the Net Metering and Easy Connection Statute. However, during my cross examination in the Company's ER-2022-0337 electric rate case, Renew Missouri's attorney and Commissioner Holsman both suggested that this approach could work in conjunction with Missouri law, and it was recently approved by the Commission for Evergy's Missouri West operations. The Company continues to have concerns about the lawfulness of this approach but putting those issues aside, should the Commission wish to make TOU rates available to net metering customers in Ameren Missouri's service territory, it makes absolutely no sense to deviate from the paradigm it has already established in the state for Evergy's service territory since it does

---

[11] Sarah Lange Direct, p. 49, ll. 8-10.

avoid the completely irrational economic outcomes Renew Missouri's proposal in this case would create. Rather, the Commission should seek a uniform approach across the state (if it is going to go down this path at all). With that said, I have attached as schedule SMW-R1 to my testimony what was originally a schedule to Evergy witness Bradley D. Lutz's testimony in File No. ER-2024-0189, and which includes the language that Evergy has now implemented to address the TOU and net metering issue. While my primary recommendation remains that advanced TOU rates should remain unavailable to net metered customers, the only reasonable alternative would be to follow the Evergy approach.

Q. If the Commission were to order any solution to offering advanced TOU rates to net metered customers, would the Company be capable of implementing such an approach in time for an expected June 1, 2025, effective date of tariffs to take effect from this proceeding?

A. No, it would simply be impossible for it to do so. TOU rates are complex. Net metering is also complex. The interaction of the two is even more so. The Company has not developed the billing logic to implement any of the approaches that have been proposed in this case, including the Evergy paradigm. The Company's billing experts would need to be given a runway of at least several months after the expected June 1st effective date of tariffs in this case in order to program and test the billing system to accommodate any offering of advanced TOU rates to net metered customers.

V. AMI OPT OUT PROVISIONS SHOULD NOT BE MODIFIED OR EXPANDED

Q. Please describe the recommendation of OPC witness Dr. Marke related to customers' ability to opt out of taking service using the Company's standard AMI metering arrangements.

A. Dr. Marke recommends that the Company adopt a policy that was agreed to by Evergy in its recent rate case, whereby customers that prefer to opt out of utilization of standard metering arrangements be allowed to "self-read" their meters the majority of the time. As a result, the fees for non-standard metering would be waived in those months and only assessed twice per year when the utility read the meter to ensure that accurate readings were being obtained periodically.

Q. Does the Company agree that this is an appropriate approach to follow for purposes of serving customers that elect to opt out of standard metering arrangements?

A. No. The Company's standard metering arrangements exist for very good and important reasons. As the Commission knows, the Company serves approximately 1.3 million electric customers. That means that every month the Company obtains and processes nearly that many sets of meter readings (some of which include hundreds or thousands of interval observations) and uses those to generate customer bills. While the creation of bills is not something folks probably tend to spend much time thinking about it, the reality is that this is an enormously complex operational task. And it is one that is greatly facilitated by automation and standardization. Simply put, having standard processes and automation of many of the meter reading and billing processes is highly efficient and *saves all customers money*. Non-standard processes undermine that efficiency and raise costs for all customers. It is certainly reasonable that customers that elect such a non-standard process be charged for the direct costs that they cause.

Q. Are the Company's non-standard metering charges reflective of the direct cost of the non-standard service arrangements requested by opt out customers?

A. Yes. The one-time upfront charge for installation of non-standard metering in the Company's tariff is $100. The ongoing monthly meter reading fee in the tariff is $40. These charges are both reflective of the costs of the activities the Company must perform directly on behalf of opt out customers.

The cost to change out a customers' meter to a non-standard meter is estimated by the Company to be between $93.17 and $101.64, based on 2024 labor rates, including wages, benefits, tools and transportation, and assuming 1.1 to 1.2 hours per job to install the non-standard metering equipment.

For monthly meter reading of non-standard metering, the Company contracts with a third-party vendor. For the months of January through August 2024, the Company's vendor conducted 3,925 meter readings within the St. Charles, Berkeley, Geraldine, and Mackenzie districts, at a cost of $179,028. That results in an average cost per meter reading of $45.61, which is just slightly higher than the $40 monthly fee charged to customers for this service.

Q. Couldn't those costs be avoided for customers if they read their own meters and supplied the readings to the Company for billing?

A. The direct costs of the third-party vendor would be avoided. However, there would still be indirect costs and operational complexities that would be inefficient and would surely raise costs for all customers in the long run.

Q. What are some of those operational complexities?

A. As I mentioned, a billing process that must be capable of generating well over a million bills a month needs to be standardized and automated as much as possible to keep overall costs down in order to promote affordability of electric service. Non-standard processes inherently result in more exceptions to be worked manually by the Company's customer accounts department, more estimated bills, more corrected bills, and more customer inquiries to the call center. This is particularly true for a non-standard process that would depend on hundreds or thousands of individual customers to timely and accurately gather and submit meter readings to the Company. Customers are not trained meter readers. Non-standard meters have a series of dials that can sometimes be difficult to interpret and translate into readings. While some customers may be comfortable taking those readings and will be able to do so timely and accurately, invariably other customers will submit faulty or delayed readings that create even more exceptions, estimates, and errant bills. On this point, I would emphasize that in addition to the need for accurate meter readings, meter readings must also be timely. Inevitably when the Company had used customer-submitted postcards in years past, there was a chronic problem with customers not sending in the readings in a timely manner. The billing process is driven by a very specific calendar. An individual's account is associated with a Bill Group. Each Bill Group comes due at varying calendar dates throughout the year in order to maintain a steady volume to accommodate weekends and holidays. If the meter reading for an individual account does not get into the system by its due date for that month, then the bill is estimated. Repetitive estimated bills lead to further manual intervention and inefficiencies, plus they introduce undesirable variations that accurate metering otherwise provides. Although an individual customer may assert that they will be diligent in delivering timely meter readings, the potential for untimely meter reading still exists across a wide number of customers, and it will undoubtedly drive up estimated bills and further manual intervention. And at some point, the faulty or missing meter reads will need to be trued up, resulting in some customers facing a large difference between what had been previously billed and what was truly owed. And beyond this, these additional non-standard processes will create a need for the Company to develop procedures and train employees to handle these situations. This is the type of complexity that will invariably make the Company's operations less efficient, more prone to unintentional error, and ultimately less affordable for all customers, given that none of the types of costs I am describing are direct costs to the opt out customer that are avoided by the "self-reading" paradigm.

Q. Dr. Marke referenced the comments of several Commissioners in response to a complaint case, which suggested the Commission's sense that the opt out fees may be considered excessive. How do you respond to those comments?

A. I appreciate the sentiment of the Commissioners and understand why it may seem on the surface that the costs appear high. However, the charges are reflective of the cost incurred to provide this service. Further, it is a form of service that is customized to meet individual customers' preferences at their election. No one is required to pay these fees. In fact, there is little if any benefit of this less efficient form of providing service. If the fees appear to be high, that is not inherently a bad thing, so long as they are cost based. The high fees act as a fair and equitable natural barrier for customers to request unnecessary service arrangements with few if any discernable benefits, and which ultimately reduces the efficiency and therefore affordability of the Company's operations for all other customers.

Q. You say there are few if any discernable benefits of non-standard metering. But don't customers have health concerns with the radio frequencies used to transmit meter readings over the AMI network?

A. There is certainly a *perception* that that is the case by some customers. But research does not bear out that AMI meters pose any health risk. The radio frequencies are very similar to a smart phone, and notably, very similar to the radio frequencies associated with the Company's legacy Automated Meter Reading ("AMR") meters that the Company's customers have been served with for more than the last two decades. In fact, the Smart Energy Consumer Collaborative, a non-utility independent third-party organization, in its publication titled "Myths vs. Facts: The Truth about Smart Meters" includes the following statements intended to dispel myths about the health impacts of smart meters like those employed in the Company's AMI network:

- In-depth review of the scientific literature by the World Health Organization (WHO) revealed that the small amount of radio frequency (RF) energy produced by smart meters is not harmful to human health.
- RF emitted by smart meters is well below the limits set by Federal Communications Commission and it is below levels produced by other common household devices like cell phones, baby monitors, satellite TVs, and microwaves. In fact, you would have to be exposed to the RF from a smart meter for 375 years to get a dose equivalent to that of one year of 15-minutes-per-day cell phone use.
- No credible evidence shows any threat to human health from RF emissions at or below RF exposure limits developed by the FCC. With over 25,000 articles

> published on the topic over the last 30 years, scientific knowledge in this area is now more extensive than for most chemicals.

Simply put, AMI meters are not causing health issues, and certainly not causing issues any more so than countless other devices that are ubiquitous in our daily lives.

Q. Do you have any other comments on Dr. Marke's testimony regarding the Evergy agreement to allow this type of "self-reading" option for opt out customers?

A. Yes. Dr. Marke's testimony discusses the Evergy West settlement, but does not reference the fact that, per the terms of the settlement,[12] Evergy's implementation of the self-read option is subject reassessment, and the company may request a variance from it, if up to 200 customers take up the self-read option. This is hardly a broad-based policy change that allows unlimited access to low-cost non-standard metering. While not referred to as a pilot per se, the settlement's description has all of the hallmarks of a limited pilot. Perhaps through this effort, Missouri stakeholders will learn more about the pros and cons of this approach before it is widely adopted and impacts all utilities and customers in the state with higher costs.

[12] File No. ER-2024-0189, Unanimous Stipulation and Agreement, Paragraph 11 (Page 8)

VI. RENEWABLE SOLUTIONS PROGRAM

Q. In your direct testimony, you quantified the expected revenues associated with the implementation of the first two phases of the RSP – service associated with the Boomtown Solar Energy Center ("Boomtown") and the Cass County Solar Energy Center ("Cass"). The Company reflected this level of revenues as an offset to its proposed revenue requirement increase in this case, and recommended this level also be established as the base amount for the RSP revenue tracker ordered by the Commission at the time the program was approved. Does Staff address these RSP revenues in its direct case, and if so, do you have any concerns about Staff's treatment of the RSP in its direct case?

A. Yes, Staff witness Amenthor discusses the revenues from the RSP in his direct testimony. I won't necessarily say that I have concerns about Staff's discussion of the treatment of RSP revenues, but rather, have some clarifications I would like to provide to address some inaccuracies and other issues that were not entirely clear in Staff's presentation.

Q. What do you wish to address?

A. Witness Amenthor reported the level of revenues that I estimated in support of my direct testimony for each RSP resource – Boomtown and Cass – in his testimony. He correctly reported the revenues I estimated associated with Boomtown. However, the number he provides for Cass was actually equal to the total RSP revenues I developed in my direct testimony (i.e., he reported Boomtown revenues correctly, but then also included the Boomtown revenues in the amount he reported for Cass, resulting in a double count of the Boomtown revenues). I believe this may have just been an issue of picking up the wrong numbers for purposes of drafting his testimony, as my understanding is that Staff's workpapers showed Staff picking up in its projected true-up adjustment total RSP revenues consistent with the total RSP revenues from my direct testimony. However, to be clear I will reiterate the revenues associated with each program phase here in Table 6 below. These calculations are supported by a workpaper provided by the Company with my direct testimony.

Table 6 – RSP Net Revenues by Program Phase

Boomtown RSP Subscriber Net Revenue	
Subscriptions (kW)	150,000
Renewable Resource Rate ($/kW-Month)	$8.27
Months	12
Total RRC Revenue	$14,886,000
Annual Production (kWh)	333,473,420
Renewable Benefits Credit ($/kWh)	$0.0388
Total RBC Credits	$12,938,769
Net Subscriber Revenue	**$1,947,231**
Cass County RSP Subscriber Net Revenue	
Subscriptions (kW)	150,000
Renewable Resource Rate ($/kW-Month)	$10.34
Months	12
Total RRC Revenue	$18,612,000
Annual Production (kWh)	338,050,180
Renewable Benefits Credit ($/kWh)	$0.0400
Total RBC Credits	$13,522,007
Net Subscriber Revenue	**$5,089,993**
Total RSP Net Subscriber Revenue	**$7,037,224**

Witness Amenthor reported the exact value shown in Table 6 above as Total RSP Net Subscriber Revenue as the projected revenues associated with Cass.

Q. Witness Amenthor goes on to say, "[t]he net actual revenue experienced as of December 31, 2024, should be used to establish the base amount for tracking purposes going forward." What clarification do you have to offer on this point?

A. There will have been no actual net revenues under the program by December 31, 2024. Recall that the Boomtown and Cass facilities are just going into service immediately preceding the true-up date in this case of December 31, 2024. The number that I calculated in direct testimony is, rather than any measurement of actual revenues, simply an annualization adjustment to reflect a known and measurable estimate of net revenues that will be realized going forward from the true-up date. RSP service will first be billed in January 2025, as the first full month of operation following the placement of Boomtown and Cass in service. This is similar to annualization adjustments that reflect changes in the levels of wages or contract prices for various commodities or services that take effect right at the end of the true up period into the test year as a representation of conditions in effect going forward when rates will take effect. So this is to say, Staff's characterization was slightly inaccurate. What the Company proposed, and I believe the Staff intended to also reflect in its case are two things:

1. An annualization adjustment of approximately $7 million associated with expected going forward net RSP revenues that are included as an offset to the revenue requirement in this case, and
2. A base amount – at that same approximately $7 million level - against which actual program net revenues will be tracked in order to ensure that customers realize 100% of the benefits of Program revenues as a reduction to the revenue requirements that are paid by all customers.

Q. Are there any other issues related to the RSP that you wish to address from any party's direct testimony?

A. Yes, briefly. Renew Missouri witness Owen recommends that the Company develop additional program resources to include in future RSP phases. Witness Owen notes the success of the program in attracting subscribers and his expectation that additional demand exists that could be used to generate net revenues from future renewable energy centers.

Q. How do you respond to the recommendations of Renew witness Owen?

A. I generally agree with his characterization of the current state of and future opportunities under the program. I would observe that his testimony correctly notes the Company's expectation of offering future additional phases of the program. As the Commission is aware, the Company's Preferred Resource Plan calls for continued investment in new renewable energy resources, complemented by dispatchable generation, to meet customers' energy and capacity needs in the future. To the extent that any future development of renewable energy resources is not needed to meet the Company's statutory RES requirement, new resources will be evaluated for use in the RSP and are likely to be subscribed in the program to the extent that customer demand exists. To that end, I do not think there is any issue in this case to be addressed by the Commission. But rather the Company and Renew Missouri are both aligned with respect to the goal of utilizing the program going forward to support new generation resources, while meeting subscribing customers' desire for access to renewable energy, and also promoting affordability of service for all customers.

VII. THE COMMISSION SHOULD NOT ORDER A TARIFF ASSOCIATED WITH GREEN BUTTON CONNECT MY DATA FUNCTIONALITY

Q. Renew Missouri witness Murray makes several recommendations related to implementation of Green Button Connect My Data functionality, suggesting that the Commission order the Company to develop this technology and order a tariff to govern its use. What is the Company's response to these recommendations?

A. Company witness Clark Allen discusses in detail the specific reasons that Green Button Connect My Data ("CMD") functionality should not be ordered by the Commission at this time. I will address witness Murray's proposal to create a tariff governing the deployment of this capability.

Q. If the Commission were to adopt Renew Missouri's recommendation to order the Company to implement this functionality, should it be the subject of a Company tariff?

A. No. Mr. Murray's recommendation related to a tariff is solely based on his speculation that the Company may not implement Green Button CMD in an appropriate manner, if ordered to do so. Essentially, this recommendation can only be a result of witness Murray's presumption that the Company will act either in bad faith or incompetently, which results in his ask of the Commission to preemptively establish strict tariff requirements governing the details of a technology implementation that should properly be subject to the Company's management. The Commission is not intended to stand in for Company management in determining how the Company conducts its business and builds its technology solutions, so long as the Company is meeting Commission rule requirements and providing reasonable levels of service to its customers. The notion that the Commission should, if it were persuaded to order or encourage the Company to adopt this technology, micromanage its deployment is counter to good regulatory policy, which relies on the utilities to manage their affairs and develop their customer facing systems and policies. Rather than undertaking such an inappropriate tariff-based approach to micromanaging utilities, the Commission should do what it is designed to do, and that is regulate the utility to ensure it is acting in the public interest. If the utility implements a program or technology solution in a manner that is unreasonable in terms of the impacts on or accessibility to customers, there are avenues for the Commission to address those issues when they arise. Using traditional regulatory oversight, including authorizing its Staff to bring forward any concerns it may have to be addressed if, and when they have been identified, is a far more appropriate approach than creating a detailed tariff to micromanage what amounts to the utility's management of its interactions and communication with its own customers. I can only imagine that if the Commission orders a tariff related to this customer interaction/communication, the number of additional Company systems, communications, and processes that parties may try to dictate the terms and administration of through tariffs, which, if adopted, would create an incredibly inefficient and bureaucratic web of regulatory complications for a utility to navigate in managing its business, which would ultimately stifle creativity, usurp management's prerogative to determine the manner in which it will run its own business, and increase costs for customers.

VIII. THE COMMISSION SHOULD NOT DICTATE THE MANNER THE COMPANY CHOOSES TO COMMUNICATE TO CUSTOMERS REGARDING OPTIONAL TIME OF USE RATE PLANS

Q. What recommendation does OPC witness Dr. Marke make with respect to TOU-related customer communications?

A. Dr. Marke suggests that the Company should use Public Service Announcements ("PSA") to educate customers about the benefits of TOU rates in order to prepare for a future scenario where higher differential TOU are rates rolled out. For purposes of this recommendation, I presume Dr. Marke means higher differential rates that would be rolled out on a default or mandatory basis, since the Company does have high differential TOU rate offerings available today for its residential customers. Dr. Marke discusses the potential benefits of TOU rates and encourages a path to facilitating greater levels of advanced TOU rate adoption. He suggests this will save participants money on their bills and at scale may reduce overall costs for all customers.

Q. What is your response to Dr. Marke's recommendation?

A. I appreciate the sentiment, and generally agree that there are real benefits that can arise from broader adoption of advanced TOU rates. That said, there are also real barriers to that widespread adoption that can and should be navigated carefully subject to the Company's discretion to manage its own business prioritization around customer communications. For that reason, I do not think it is appropriate for the Commission to weigh in with a dictate about TOU communications for modified TOU rates that are not even proposed in this case.

Q. How is the Company communicating about TOU rates with its customers today?

A. Company witness Kelly Doria describes our communications efforts on the topic in her rebuttal testimony, as well as describes why use of a PSA approach is not viable. In summary, Ms. Doria explains that this would not truly be a PSA, thus it is not a cost-free option as Dr. Marke's testimony may imply. Ms. Doria goes on to explain that these types of advertisements aren't effective, and we have other, likely better, options for getting out the message that Dr. Marke desires. The Company appreciates that Dr. Marke specifically mentioned in his testimony that he did not take issues with the Company's communications on this topic to date.

Q. Why do you believe that the Company should retain management discretion with respect to the nature and timing of changes to those communications?

A. There are at least a couple of compelling reasons that this is the case. First, Dr. Marke notes in his testimony the recent situation experienced by Evergy related to a backlash to a TOU rollout strategy that had been ordered by the Commission. While its certainly true that that was a unique situation that had a lot of things contributing to the dynamic that developed, it is also illustrative of the fact that this issue is, or at least can be, a sensitive and surprisingly controversial topic at least amongst some folks. Rather than being dictated to message customers on the topic, the utility, with its prerogative to manage its business and maintain relationships with its customers, ought to be allowed to try to "read the room" with respect to the prevailing sentiments on the topic and craft its own communications in terms of both content and timing on such topics that may ultimately influence its standing with its customers.

Second, as I testified to at length in the Company's prior electric rate review (File No. ER-2022-0337), increased adoption of TOU rates can negatively impact the Company's opportunity to actually realize the revenues that the rates ordered by the Commission in this case are designed to produce. This is because TOU rates provide customers with savings opportunities if they either select a rate that is a good fit for their load profile, or if they actively manage their usage to optimize their cost of electric service according to the TOU rate schedule. These savings manifest as lower customer bills than were presumed in a rate case based on legacy rate application – i.e., lower Company revenues than would exist on the legacy rates on which customers were previously taking service during the determination of trued up test year revenues. My prior rate case testimony presented the Company's request for a TOU rate switching revenue tracker to insulate it against significant revenue erosion between rate cases if TOU adoption rates were high. While most parties to our case opposed the concept of the tracker, none meaningfully challenged the notion that revenue erosion is a real phenomenon associated with rate switching with real financial implications for the utility.

Ultimately, this ability to manage energy costs through adoption of rate options that produce savings opportunities is good for customers, and the Company supports the utilization of TOU rates to create those benefits for customers. But it is important to the Company that any increases in adoption be gradual to avoid significant transient revenue impacts that may reduce the Company's opportunity to recover its prudently incurred costs and earn a reasonable return on its investments used to provide service to customers. It is noteworthy that the Commission declined the opportunity to institute the rate switching tracker that would have aligned the Company's incentives with promoting a more rapid adoption of TOU rates and the benefits those could bring to customers. Given the real financial consequences of rapid TOU rate adoption on the Company's shareholders in the absence of a tracker, it should be within the Company's discretion to determine its communication strategy in a way that it can use to manage and/or mitigate the pace of revenue erosion.

For these two reasons, I do not believe it is appropriate for the Commission to step into the role of dictating to the Company the type and pace of communications around TOU rates.

Q. Are there any other points raised by Dr. Marke on this topic that you wish to address?

A. Yes. As a part of the justification for his recommendation regarding TOU rates, Dr. Marke states:

> A failure to properly promote TOU rates in a manner that results in meaningful savings to customers would call into question the prudence of the hundreds of millions of dollars spent on the collective AMI hardware, software, and LTE private operating network investments. To date, the espoused benefits for ratepayers for this collective investment has been minimal at best. To rectify this, customers need to be engaged in a meaningful conversation for why pricing electricity in a manner that reflects its actual costs is in their best interest.[13]

I strongly disagree with this suggestion for multiple reasons. First, Dr. Marke completely fails to either understand or acknowledge the Company's primary business case for making its AMI investment. The Company's legacy AMR network was at end of life and was soon to be completely unsupported by the vendor that operated the communications network for that AMR system, making it obsolete. The AMI investment was not an early replacement of an otherwise viable metering system that was creating stranded costs with the promise of some level of benefits to offset those stranded costs. But rather, the AMI investment was made based on an evaluation of options to replace an obsolete, end of life, system, and to that end the AMI system was a cost-effective means in and of itself for obtaining meter data needed to bill

[13] File No. ER-2024-0319, Geoff Marke Direct Testimony, p. 28, ll. 9-15

customers. It is noteworthy that by the time the Company has completed full installation of its AMI meters, which will occur this calendar year, it anticipates annual operations and maintenance savings of $16 million relative to the time period prior to its AMI deployment.[14]

But moreover, customers *are* experiencing real benefits from the Company's investment in AMI already. For one thing, residential customers now have more rate options available to them. And thousands of them have made the election to adopt advanced TOU rates that help them manage their energy bills. Beyond that, the Company is providing tools for customers to understand and thereby better manage their energy usage irrespective of what rate plan they are on, through its My Energy Manager portal. Additionally, the Company and its customers are saving money using remote connect/disconnect capabilities, and the meters themselves are providing operational data to improve service to customers through things like more rapid outage detection, detection of theft of service, and identification of malfunctioning meters or hot meters that may have a loose connection. The notion that customers are not benefiting from the Company's AMI system simply does not square with reality.

IX. THE COMMISSION SHOULD NOT ORDER A RESIDENTIAL BATTERY STORAGE PILOT PROGRAM

Q. What is Renew Missouri witness Owen's recommendation related to residential battery storage?

A. Witness Owen recommends that the Commission order the Company to essentially duplicate a pilot already being undertaken in the state by Evergy.

[14] This was addressed in the Company's response to Staff DR 0331 in this case.

Q. Do you agree that the Commission should order the Company to propose such a pilot in its next rate case, as Renew Missouri recommends?

A. No. As may be evident based on a review of the various issues I have addressed throughout this testimony, there seems to be a theme of more and more parties to cases asking the Commission to intervene in management decisions regarding the operations of the utilities they regulate. This recommendation is yet another instance of that in this case. The Company should not be dictated what type of pilots it proposes. Particularly given the fact that such a pilot is already ongoing in the state, and the Company's efforts would largely duplicate that ongoing study. While Ameren Missouri and Evergy obviously do have distinct customer bases, I do think that for purposes of understanding this type of program, there would be plenty of learnings from the Evergy pilot that could potentially be extrapolated to the Company's service territory. But moreover, while witness Owen discusses some categories of potential benefits from such a program, he provides no evidence whatsoever of the level of those benefits with which to even screen such a program for cost effectiveness. The decision to propose offering discretionary programs to customers ought to be the prerogative of Company management, subject to the approval of the Commission.

Q. Do you have any other reactions to witness Owen's discussion of the battery storage topic?

A. Yes. Witness Owen presents this recommendation as if the Company has expressed no plans to promote the utilization of batteries as a part of its system at all, referring to his proposal, for example, as an opportunity for the Company to "[b]egin a path to integrate more battery resources."[15] I'm surprised at Renew Missouri's allusions to a lack of consideration

[15] File No. ER-2024-0319, James Owen Direct Testimony, p. 18, ll. 7-8

of battery technology by the Company. My surprise is based on the fact that Renew Missouri is a signatory to a recent Stipulation and Agreement that resolved the Company's request for a CCN to construct the Castle Bluff simple cycle gas peaking plant that was approved by the Commission recently in File No. EA-2024-0327, which included a commitment by the Company to file for a CCN[16] for at least 200 MW of battery storage with the Commission, with a goal of implementing new battery storage resources by 2027. That Stipulation also reflects the Company's commitment to model 800 MW of battery storage in its 2026 IRP for implementation by 2034. These commitments are a demonstration of the Company's interest in advancing battery storage solutions on its system. Given those commitments, along with the other policy related considerations that I discussed just above, I recommend that the Commission deny Renew Missouri's request to order the Company to file a residential battery storage program in its next electric rate review.

X. ENERGY COMMUNITY TAX CREDIT BONUS

Q. CCM witness Palmer recommends that the Company prioritize taking advantage of provisions of the Inflation Reduction Act that provide enhanced tax credits for renewable energy resources cited in "energy communities". Is the Company considering the energy community bonus in its pursuit and implementation of new renewable energy centers?

A. Yes. The Company is very aware of and keenly interested in the energy community tax credit bonus, as it is an opportunity to increase the affordability of service for its customers while adding new clean energy resources to its system. While not every renewable energy center can or will be located in an energy community, many of the Company's existing

[16] The Company filed a 60-day notice on January 6, 2025 in furtherance of that commitment.

projects and projects under development do qualify for this enhanced tax credit. The Company also considers the availability of the energy community bonus when evaluating future potential locations for renewable energy projects. Specifically, the Company's existing Boomtown and Cass solar facilities qualify for this bonus, as will the New Florence facility that is being developed as a Community Solar resource, and for which the Commission recently granted a CCN in File No. EA-2024-0212. Other future projects under development and/or consideration also may be eligible for this enhanced tax credit.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

NET METERING OPTION FOR RESIDENTIAL TIME OF USE
ELECTRIC

PURPOSE:

To modify the DETERMINATION OF NET ELECTRICAL ENERGY section of the Company Net Metering Interconnect Application Agreement tariff, sheet 113 to allow residential customers receiving service under a Time of Use (TOU) rate schedule to participate in Net Metering.

APPLICABILITY:

Applicable to Customer-Generators with a Company approved interconnection agreement, receiving service under Schedule RTOU, RTOU-2, or RTOU-3. All aspects of the Company Net Metering Interconnect Application Agreement tariff, sheets 100 through 119.9, except for the DETERMINATION OF NET ELECTRICAL ENERGY section are applicable to customers receiving service as a result of this option.

DETERMINATION OF NET ELECTRICAL ENERGY UNDER TOU RATE SCHEDULES:

Net electrical energy measurement shall be calculated in the following manner:

A. For a Customer-Generator, the Company shall measure the net electrical energy produced or consumed during the billing period for the applicable TOU period (peak/off-peak/super off-peak) in accordance with normal metering practices, either by employing a single, bidirectional meter that measures the amount of electrical energy produced and consumed, or by employing multiple meters that separately measure the Customer-Generator's consumption and production of electricity;

B. If the electricity supplied by the Company exceeds the electricity generated by the Customer-Generator during a TOU period, the Customer-Generator shall be billed for the net electricity supplied by the Company in accordance with normal practices;

C. If the electricity generated by the Customer-Generator exceeds the electricity supplied by the Company during a given TOU period, the Customer-Generator shall be credited with the product of the excess kilowatt-hours generated during the TOU period and the rate identified in Parallel Generation Contract Service tariff, Sheet 102.1 in the following billing period. This rate is calculated from the Company's avoided fuel cost;

D. The Customer-Generator shall be billed for the appropriate Customer charges for the billing period in accordance with the Company Obligations section of the Company Net Metering Interconnect Application Agreement tariff;

E. Any credits granted by this subsection shall expire without any compensation at the earlier of either twelve (12) months after their issuance, or when the Customer-Generator disconnects service or terminates the net metering relationship with the Company.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues for Electric Service.	)))	Case No. ER-2024-0319

AFFIDAVIT OF STEVEN WILLS

STATE OF MISSOURI	**)**
	) ss
CITY OF ST. LOUIS	**)**

Steven Wills, being first duly sworn states:

My name is Steven Wills, and on my oath declare that I am of sound mind and lawful age; that I have prepared the foregoing *Rebuttal Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Steven Wills
Steven Wills

Sworn to me this 16th day of January, 2025.