Exhibit No. 9

Ameren – Exhibit 9
Steven M. Wills Testimony
Surrebuttal
Case No. ET-2025-0184

Exhibit No.:	
Issue(s):	Staff Tariff
Witness:	Steven M. Wills
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	ET-2025-0184
Date Testimony Prepared:	November 3, 2025

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ET-2025-0184

SURREBUTTAL TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
November, 2025

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SURREBUTTAL TESTIMONY

OF

STEVEN M. WILLS

FILE NO. ET-2025-0184

I. INTRODUCTION

Q. Please state your name and business address.

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

Q. Are you the same Steven M. Wills that submitted Direct Testimony in this case?

A. Yes, I am.

II. PURPOSE OF TESTIMONY AND OVERVIEW CONSIDERATIONS

Q. To what testimony or issues are you responding?

A. I am responding to the Rebuttal Testimony and Report of the Staff of the Missouri Public Service Commission ("Staff") as well as to the rebuttal testimony of Office of Public Counsel ("OPC") witness Lena Mantle. I also address issues or comments contained in the rebuttal testimonies of Staff witness Jim Busch, OPC witness Geoff Marke, Missouri Industrial Energy Consumers witness Maurice Brubaker, and Sierra Club witness Carolyn Palmer.

Q. What topics will you address?

A. First, I will provide an overview of the parties' general positions and postures in this case with recommendations on how the Commission can navigate this case to achieve the dual goal of creating an environment that promotes and attracts economic development in the state of Missouri while providing the reasonable assurance required under Senate Bill 4 ("SB 4") that large load customers' rates reflect their representative share of the costs of providing their service and that existing customers will not bear unjust or unreasonable costs arising from the service to those customers.

Next, I will respond to specific positions and allegations of Staff and OPC, including responses to many of Staff's criticisms of the Company's proposal as well as facts demonstrating the unreasonable nature of Staff's own proposal that it introduced in its Rebuttal Report.[1] I will discuss why the Staff's contentions related to the operations of regulatory lag are unbalanced and represent poor policy. I will also address the issues raised by both Staff and OPC related to the Fuel Adjustment Clause ("FAC") including identification of numerous errors and erroneous conclusions, in order to dispel misconceptions and generally demonstrate that significant changes to the FAC are unwarranted. Finally, I address a number of miscellaneous issues raised in the rebuttal testimony of various parties.

Q. Please summarize the key takeaways from your testimony.

A. 1) The Commission's focus in discharging its duties under SB 4 should be on ensuring that large load frameworks contain sufficient protections to ensure a long-term revenue stream from large load customers. Rate design issues are largely a distraction in this case and do little, if anything, to address long-term revenue certainty.

2) Staff's analysis of the Company's proposal is so riddled with massive errors – errors which I will meticulously document later in this testimony

[1] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, filed September 5, 2025.

and which introduce literally *billions of dollars of inaccuracy into Staff's analysis* - that it must be completely discarded by the Commission and given no weight whatsoever in evaluating the Company's proposal. More specifically:

- Staff misapplies the Company's proposed rate in a manner that causes Staff to misrepresent the revenues large load customers would provide under the Company's proposal, understating those revenues by literally billions of dollars across the horizon of Staff's analysis.
- Staff misapplies the formula in the FAC and therefore misrepresents the impact of its hypothetical large load customer on the net energy costs borne by existing customers, overstating that impact by hundreds of millions of dollars.
- Staff makes other errors that lead it to either understate the revenues large load customers would contribute or to overstate their cost impacts, including mismatching its revenue growth assumption with the period over which that growth occurs, omitting securitization contributions large load customers would make under Rider SUR,[2] and also omitting the tax benefits of accelerated depreciation.
- In addition the foregoing outright mistakes, Staff makes unreasonable assumptions that are further biased toward making it appear that adding large load customers will harm existing

[2] Rider SUR is the securitization charge rider the Commission approved in connection with costs approved for securitization arising from the retirement of the Rush Island Energy Center in File No. EF-2024-0021.

customers, such as assuming that future retail rates will only grow at a 2% compound annual rate despite the elevated investment environment all electric utilities, including Ameren Missouri, find themselves in today, overstating operation and maintenance expense of future power plants, and assuming unrealistically long periods of regulatory lag occur between Company rate cases. Further, Staff ignores the potential upside benefit of large load revenue contributions through voluntary clean energy programs.

- The net effect is that Staff's "net harm" analysis, when corrected for errors and unreasonable assumptions, reverses to be slightly *beneficial* to existing customers even in Staff's *worst case and least likely scenario* (prior to even considering potential clean energy revenues), but shows a *massive* benefit of up to $5.7 billion accruing to existing customers from large load customers over 35 years in a more likely scenario where those customers stay on the system for the long term.

3) Staff's own large load rate proposal is completely unworkable and unreasonable as a solution if the state of Missouri wants to compete for the economic development opportunity that large load customers represent. Staff's proposal is completely uninformed by input from utilities, prospective customers, and other key sources of information (including consideration of the tariff offerings for large load customers in other states), and is extreme in many ways such that it does not reflect

reasonable commercial terms for large load service, nor sound regulatory policy. Consequently, it must be rejected *in its entirety*.

4) Staff's proposals related to regulatory lag are unbalanced and represent poor policy and should be rejected.

5) Significant changes to the FAC are unnecessary and, if adopted, would be a recipe for disaster in the form of either incredible confusion and complexity, discriminatory treatment of large load customers, or both. The FAC's role in determining the impacts of large load service must be viewed in the totality of Missouri's ratemaking paradigm. Staff and OPC's proposals and analyses are flawed in several key ways, including because they completely ignore a key part of the equation – base rate revenues large load customers will pay to cover net energy costs - and also lack important context for understanding the impacts of large load customers on existing customers.

Q. You indicate that Staff's proposal is unworkable and unreasonable. Before getting into the details, would you please provide some context for that opinion?

A. Yes, and this context is also discussed in the Surrebuttal Testimony of Ameren Missouri witnesses Rob Dixon and Ajay Arora. The large load issue in this case should first and foremost be viewed as the historic opportunity that it is to attract massive investment to the state and avoid losing those investment opportunities and the benefits they will bring to other states with whom Missouri is competing. The large load issue, of course, must also be viewed in the context of the requirements of SB 4, which requires that the Commission conclude that there is reasonable assurance that large load customer rates will reflect their representative share of costs and will not result in unjust or unreasonable costs arising from their service being imposed on existing customers. It is critical, therefore, to be cognizant of the commercial terms reflected in any large load tariff proposal, and how those terms:

1) are reasonably in line with, so as to be competitive with, terms being established in the industry across various jurisdictions with whom Missouri is competing,

2) meet the needs and preferences of potential customers where those can reasonably be accommodated, and

3) provide reasonable assurance that large load service under those terms will not result in unjust or unreasonable impacts on existing customers.

Staff's proposal fails to achieve any of these three principles.

Q. Why do you say that Staff's proposal fails at achieving these three principles?

A. Frankly, I've never seen anything quite like the rate structure that Staff has constructed – except, of course, for Staff's very similar rate proposal in Evergy's large load tariff case (File No. EO-2025-0154) going on in parallel with this proceeding. Staff admits its approach is "novel."[3] It is certainly far afield of the large load rate structures in the industry with which I am familiar. Staff's proposal is marked by a lack of any meaningful basis in the utility's cost of serving large loads, is biased toward *overcharging* large load customers, and reflects extremely onerous terms of service for prospective large load

[3] File No. EO-2025-0154, Tr. (Vol. 2) p. 264, ll. 9-12 (Mr. Busch, responsible for the Staff's proposal in this case when it was submitted, testifying as follows about Staff's Evergy proposal, which is essentially the same proposal made in this case: "Q. Would you agree that the Staff's approach could be characterized as a novel approach? A. A novel approach, I think I could agree with that."

customers that are neither commercially reasonable nor aligned with service terms being adopted in the industry at large.

Moreover, Staff appears to have made no effort whatsoever to understand large load customers and their needs and preferences.[4] As Staff witness James Busch testified during the Evergy hearings, to his knowledge Staff made no contact with any large data center customer in developing its proposal, didn't consult with Evergy about Staff's proposal in that case, and did not consult with the Company about Staff's proposal before it developed and filed it.[5] The Company, however, has spent significant time developing an understanding of the needs and priorities of such customers and the competitive landscape Missouri faces vis-à-vis other states, and has developed a proposal that aligns with customer priorities, and the market, while still providing the assurances required under SB 4. Based on the Company's interactions with several different prospective customers, we have come to understand the key aspects that such customers are seeking above and beyond the basic availability of power. First and foremost, they are seeking a good utility partner that will work with them to establish transparent and fair pricing and contract terms. Beyond that, many of them are also actively seeking utilities that can help them achieve clean or carbon free energy goals. In my experience, large load customers generally express a willingness, indeed a preference, to pay their fair share (which the statute expresses as paying a representative share). But in doing so, they also do not want (nor should they be

[4] File No. EO-2025-0154, Tr. (Vol. 2) p. 214, ll 11-19.
[5] File No. EO-2025-0154, Tr. (Vol. 2) p. 213, ll. 11-19 ("I am not aware that Staff may any contacts with any large data center customer [before developing its proposal]" and to Mr. Busch's knowledge, the answer is "no" in terms of whether Staff sought input from any such customer. *Id*, p. 214, ll. 14-17 (Mr. Busch: "I don't believe it did" in response to a question as to whether Staff sought Evergy's input on the quite similar Staff proposal made in Evergy's case), to Mr. Busch's knowledge; *Id.* p. 220, l. 9 to p. 221, l. 12 (Mr. Busch indicating Staff doesn't "have the time or the Staff" to work with potential customers and that he would "be shocked to find out …. they were able to" when asked whether Staff had engaged in any such consultation).

expected) to pay *more* than their fair share. Staff's rate, as I will discuss in more detail, is neither transparent nor a reasonable representation of large load customers' fair (or representative) share. And on its face, it clearly wasn't the product of any meaningful interaction with or effort to understand the needs of prospective large load customers.

In summary, the Staff's approach is severely flawed and one can validly question whether the Staff even designed it with the thought that it would actually ever be applied to at least one category of customers, data centers, which are the single largest potential large load customer and economic development prospect the Company expects to serve (and the same is true for Evergy) in the immediate future. One should question this because we know that Mr. Busch testified in Evergy's case and filed testimony in this case that flat out expressed the opinion that serving data centers are not worth the risk: ("Q. But are not the economic advantages of locating large data centers in Missouri worth the risk? A. Not in my opinion.")[6] And not only is this Mr. Busch's opinion, but he also testified under oath that he was speaking for the Staff:

> Q. So if I understood your answer, you would agree that the legislature wasn't saying keep data centers out of Missouri? A. I don't believe that's what they [the legislature] were saying. I believe that's what *Staff is saying* (emphasis added).[7]

III. THE COMMISSION SHOULD FOCUS ON WHAT MATTERS, RATHER THAN MISS THE FOREST FOR THE TREES, AS STAFF HAS DONE

Q. What do you see as the primary theme underlying Staff and OPC's concerns about the Company's proposed large load framework?

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[6] File No. ET-2025-0184, James A. Busch Rebuttal Testimony, p. 5, ll. 15-17.

[7] File No. EO-2025-0154, Tr. (Vol. 2) p. 268, ll. 14-18. Mr. Busch also testified that he was speaking for the Staff generally when opined that serving data centers in Missouri was not worth the risk. *Id.*, p. 261, ll. 5 – 15.

A. Both Staff[8] and OPC[9] voice significant concerns with what they characterize as the potential for "stranded costs" associated with the provision of large load service. Both parties question the business model of data centers (i.e., the most likely large loads to seek service in the near term), and specifically those that are investing in Artificial Intelligence ("AI") technologies, and the durability of their commitment to paying retail electric rates for the long term.

Q. How can the Commission address this concern?

A. While I reject the notion that stranded costs, per se, are at all likely to occur, the solution to the real underlying concern of Staff and OPC in the context of large loads is fairly simple and straightforward – make sure that large load customers have a long-term commitment to providing a sufficient level of revenues to help cover the cost of long-lived assets that are being accelerated on their behalf.

Q. In what ways does Staff's approach in this case miss the mark related to this simple and straightforward solution of focusing on revenue certainty?

A. Staff's Rebuttal Report doesn't spend much time at all explaining the rationale for the tariff/contractual provisions that they propose to create long-term revenue certainty, nor does Staff ever provide *any* analysis that shows what large load customers would pay under Staff's proposal. Rather, Staff spends an inordinate amount of time and effort on rate design (i.e., the "trees" of *how* to collect the revenues that are obscuring the "forest" of creating long-term revenue certainty) – trying to come up with a brand new paradigm to slice and dice the Company's revenue requirement into different components and then subsequently design rates that will result in the billing of customers in a very

[8] File No. ET-2025-0184, James A. Busch Rebuttal Testimony, p. 5, ll. 1-14.
[9] File No. ET-2025-0184, Geoff Marke Rebuttal Testimony, p. 29 ll. 8-26.

granular way. To illustrate, the Company's proposal based on the 11(M) Large Primary Service tariff has basically four charges[10] – a customer charge, a demand charge, an energy charge, and a reactive demand charge. These charges are relatively simple and efficient in aligning with the basic and recognized cost classifications that drive costs, cost allocation, and rate designs for most utilities. Staff, by contrast, has designed a massively complex system of rates including as many as *fourteen* different rate elements, several of which can fairly be described as opaque and confusing charge types that are not well aligned with traditional cost allocation methodologies or industry standard rate structures (e.g., Staff's Fixed Variable Revenue Contribution charge).[11] This increased granularity of charges is simply not necessary to create just and reasonable rates for large load customers. If a fair allocation of the Company's revenue requirement says that large load customers should pay a thousand dollars, that thousand dollars can be generated on bills by applying 4 charge types, 14 charge types, or 40 charge types. But the result is still a thousand dollars of revenue that covers the representative share of costs that are appropriately allocated to the large load class. The number and granularity of unique charges on the bill does nothing to ensure that the revenue actually shows up.

What Staff doesn't do is focus on the terms that almost everyone in the industry, including Ameren Missouri in this case, focuses on in order to protect existing retail customers – contract term, minimum demand, credit and collateral provisions, and termination rights and fees. These are the parameters on which the Commission should

[10] These rate elements have differentiated rate levels between summer and non-summer seasons, and there is also a low-income pilot program charge that I am lumping together with the customer charge for purposes of this summary.
[11] Staff doesn't even propose values for two of its 14 charges, making it even more difficult for a prospective customer to gauge what service to the customer under Staff's tariff would cost.

focus. Sure, rate designs and rate levels eventually matter. But those rate designs and rate levels are going to be evaluated and reset roughly every couple of years when the Company files rate cases. And the Commission will have the opportunity to review cost allocations to ensure that they are and continue to be appropriate because the Commission has ongoing oversight and ratemaking authority over service to all customers, including large load customers. This case should be focused on laying out the framework that is going to enable the Company to capture the large load customers in the first place and on the contract structures that ensure long-term revenue stability when we bring a new large load customer onto the system. Period.

Q. You said previously that you don't agree with the notion that costs are likely to be stranded but then alluded to what you called the real underlying concern of Staff and OPC. Can you elaborate on that point?

A. Staff and OPC's references to stranded costs are really misnomers in this situation. The term stranded cost generally refers to costs of resources or infrastructure that are or become no longer useful in providing service prior to the end of their useful life, when there is still unrecovered investment on the utility's books. Generation that is *accelerated* to serve large load customers is not possible to be stranded. This is the case because, as the term "accelerated" implies, the generation that is being built to serve large loads is generation that would be needed a few years later anyway, to replace retiring generation and/or meet other load growth. Power plants that utilities construct, even if primarily driven by load growth from large load customers, will be needed to provide service to the whole system for the foreseeable future, and can meet retail customer needs and/or create revenues in wholesale power markets by serving the market at large. That said, I certainly appreciate that providing service to large load customers is likely to cause those significant investments in generation resources sooner than they otherwise would. And absent large loads to contribute revenues toward the revenue requirement of the acceleration of those resources, the potential exists for existing customers to bear additional costs on a net present value basis. To that end, Staff and OPC's real underlying concerns of potential cost impact on existing customers reflect a legitimate perspective – one that I believe was shared by the legislature in passing the provisions of SB 4 that require utilities to create large load tariffs. But that's exactly the point of Ameren Missouri's filing in this case. And that is why revenue certainty is such an important element of the large load framework, as I just explained. The Company's proposal includes a robust framework that reflects a requirement that prospective large load customers bring a long-term financial commitment along with their request for service that will reasonably ensure that those customers pay their representative share of costs over time.

Q. As you mentioned previously, Staff and OPC both question the viability of the AI business model[12] that some large load customers seeking service may be pursuing. Should the Commission's assessment of the long-term viability of AI drive their decision in this case?

A. No. Company witness Darryl Sagel's Surrebuttal Testimony provides some perspective on the data center trends as counterpoint to some of the concerns raised by Staff and OPC. But again, the whole question of what the Commission's view on AI is becomes moot if the contractual structures and the creditworthiness of the actual entities taking service (or the collateral that they provide in lieu of or to supplement their

[12] File No. ET-2025-0184, James A. Busch Rebuttal Testimony, p. 5, ll. 1-14 and Geoff Marke Rebuttal Testimony, p. 16, l. 13 to p. 24, l. 19.

creditworthiness) is what creates the revenue certainty. If we are serving financially strong customers that have the wherewithal to pay their bills or if there is adequate financial security and/or collateral to ensure those bills can be paid, then there is no reason to speculate on the underlying fundamentals of their business model. We certainly don't do that as utilities (and neither does the Commission) with any other customers we serve. Dr. Marke of OPC criticized the Company's risk analysis for failing to consider the type of business model concerns he articulated.[13] I disagree. While we didn't delve into *why* customers might terminate their service – i.e., whether the driver would be a flawed business model - the Company's risk analysis evaluated impacts on existing customers in scenarios that included the large load customers that the Company would serve all terminating their service prior to the fulfillment of their contractual terms. The credit and collateral provisions serve to ensure that the large load entities that the Company serves will have the financial wherewithal (or post sufficient collateral) to pay for the commitments they made, whether their business ventures succeed or not. Dr. Marke also suggested that the Commission's job in this case is to manage risk and assign it appropriately, which requires an assessment of uncertainties around this load.[14] Again, the Company is the only party that did provide a risk analysis – and it was an extremely robust analysis that gives the Commission the information and tools it needs to conclude that the Company's plan is appropriate for addressing the risk associated with large loads, irrespective of the nature of their operations. I'm perplexed at why Dr. Marke articulated his support for Staff's proposal[15], given that Staff recommends a much shorter contract

[13] ET-2025-0184, Geoff Marke Rebuttal Testimony, p. 24, ll. 18-19.
[14] ET-2025-0184, Geoff Marke Rebuttal Testimony, p.2, ll. 16-18.
[15] ET-2025-0184, Geoff Marke Rebuttal Testimony, p. 45, ll. 1-4.

term than Dr. Marke recommends – indeed, an even shorter contract term than that proposed by the Company – and has focused on rate design issues while conducting no analysis whatsoever of the efficacy of the Staff's proposal in generating revenue certainty to protect existing customers from the risk of higher costs.

Q. Focusing on the "forest" for a moment, can you please comment on the contract structure proposals made by the Company and Staff and how they provide the revenue certainty that you recommend the Commission to focus on?

A. The Company's proposal is much more thoughtful and transparent than Staff's. The Company's proposal is based on months of conversations with potential large load customers, review of approaches being taken elsewhere in the industry, and an extremely thorough analysis of the efficacy of the proposal in the context of the Company's Integrated Resource Plan ("IRP"), as discussed in depth in the risk analysis presented in my Direct Testimony in this case. That risk analysis provides clarity to the Commission about the potential range of impacts of large load service on existing customers under a variety of future assumptions about the retail rates and contractual provisions under which large load customers will take service.

Staff, in contrast, has put forth a proposal that is very opaque and does not appear to have been subjected to any analysis of its impact on existing customers. Staff's proposal is actually, in some ways, less stringent in terms of the revenue certainty it provides for than the Company's. And in other ways, Staff's proposal is extraordinarily onerous on prospective customers in a way that is simply unfair to them. It fails to strike an adequate balance that will attract economic development while also protecting existing customers.

I will take a moment just to walk through the four major areas that I identified as being core considerations that the industry is coalescing around as the cornerstones of large load frameworks.

Contract Term – Staff's proposed term is actually shorter than that proposed by the Company (a ramp period plus 10 years under Staff's proposal versus a ramp period plus 12 years in the Company's), providing less long-term revenue certainty than the Company's proposal.

Minimum Billing Demand – The Company proposes a transparent minimum billing demand of 80%[16] of the customer's contract demand. Every bill will have this minimum level of revenue that is easily discernable based on the customer's contract demand. Staff's proposal includes no minimum demand. It does, however, include a web of complex imbalance and deviation charges that create some de facto level of minimum revenue. How much minimum revenue? It's almost impossible to ascertain that based on the complex and interactive nature of Staff's proposal – and Staff has provided no analysis or perspective to characterize the level of revenue protection that its scheme is designed to ensure. That's extremely problematic to say the least for the Commission, the utility, and a prospective customer.

Credit and Collateral Requirements – The Company has detailed credit and collateral terms developed in consultation with its internal department of professionals within the Company with subject matter expertise on the topic. Staff's tariff, perplexingly, includes only a generic reference to a pledge of collateral "as ordered by the Commission

[16] This percentage is a change from the Company's original filed position and is explained in the surrebuttal testimony of Ajay Arora.

in this proceeding," essentially leaving to the Commission to figure out on its own more detailed collateral provisions for implementation in this case.

Termination Fees – The Company has a well-defined termination fee structure that would be instigated upon advanced notice from a customer of its intention to discontinue its electric service, and which was subjected to economic analysis as a part of the risk analysis presented in my Direct Testimony. Staff has a termination fee that has no provision for the customer to choose to terminate service but rather is automatically triggered if and when the customer's load drops to less than 50% of the expected load for a mere three straight months. This is truly remarkable! Termination fees exist to ensure the long-term revenue stream I have been discussing is available to provide a fair contribution to the costs of long-lived assets if a customer ceases to take service altogether, which should obviously be at the customers' election. If they don't choose to terminate service but just use at a lower level than planned, the minimum demand requirement is the appropriate mechanism to provide revenue certainty – not an artificially invoked termination fee. Because of the size of prospective customers and the size of the investments being accelerated to serve them, the potential exists for exit fees to be very substantial sums of money, even for entities the size of hyperscale data center customers. It is easily imaginable under Ameren Missouri's proposed paradigm for exit fees to approach or exceed a *billion* dollars. That Staff would propose to trigger mandatory payment of such fees due to a three-month reduction in usage is preposterous. A three-month reduction in usage is *not* a clear indication of a permanent termination of service. Presumably such a customer would continue to exist on the system and provide retail revenues going forward (they would continue to pay the significant ongoing service charges associated with their continued operations). Yet, they would be required to pay the very substantial exit fees immediately despite the customer's likely intent to continue operations in the service territory. This simply makes no sense whatsoever.

Collectively, the picture that emerges is a stark contrast between the two proposals. Ameren Missouri has a coherent set of contract and tariff parameters that work to provide necessary revenue certainty while also being cognizant of the needs of large load customers. The totality of the effect of these terms has been analyzed in depth in the risk analysis presented in my Direct Testimony. Staff's proposal amounts to a haphazard set of terms and conditions that in some cases are less robust than the Company's (term length and credit/collateral provisions), in some cases are nearly unintelligible in terms of their expected impact (what is the minimum revenue level under Staff's web of imbalance charges that stand in for an actual and transparent minimum demand charge?), and/or are commercially unreasonable in the extreme to customers (termination fees with no optionality for the customer itself, but whereby the customer could be hit with exorbitant fees when they are not actually terminating service). Staff's proposed terms quite simply miss the mark. The Company's terms, in contrast, are a cohesive package that strikes a reasonable balance between the flexible commercial terms needed to attract economic development and a risk-tested structure that creates the revenue certainty that provides the reasonable assurances required by SB 4.

IV. STAFF'S ANALYSIS OF AMEREN MISSOURI'S PROPOSAL IS RIDDLED WITH *MASSIVE* ERRORS AND UNREASONABLE ASSUMPTIONS MAKING IT WHOLLY UNRELIABLE

Q. What positions does Staff take in its Rebuttal Testimony and Report with respect to Ameren Missouri's proposed approach to large load service?

A. Staff opposes the Company's proposed tariffs and programs. Some specific Staff claims include:

> Ameren Missouri's proposed LLCS tariffs, associated riders, and other tariff changes will not prevent other customer classes' rates from reflecting unjust and unreasonable costs to other customers.[17]

…and also….

> The analysis provided by Mr. Wills has no predictive value for the actual rates Missouri ratepayers should be expected to pay, and is not reliable for determining whether its proposed LLCS treatment complies with the statutory requirement that in approving LLCS rates and terms, this Commission "reasonably ensures such customers' rates will reflect the customers' representative share of the costs incurred to serve the customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers."[18]

…and also…

> …[T]hrough the operation of the FAC, for every 876,000 MWh of new load, the addition of an LLCS customer will raise the bills of existing Ameren Missouri customers approximately $22 million, each year, from the time the customer comes on to the system until the customer's load is recognized in a rate case.[19]

…and also…

> Ameren Missouri shareholders will benefit from around $31.6 million of new net revenue from the example 100 MW new LLCS customer, every year, until that customer and revenue level is recognized in a rate case.[20]

…and also…

[17] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 3, ll. 19-21, filed September 5, 2025.
[18] File No. ET-2025-0184, *Staff Recommendation/Rebuttal* p. 1, ll. 11-17, filed September 5, 2025.
[19] File No. ET-2025-0184, *Staff Recommendation/Rebuttal* p. 4, ll. 3-7, filed September 5, 2025.
[20] File No. ET-2025-0184, *Staff Recommendation/Rebuttal* p. 5, ll. 11-13, filed September 5, 2025.

> However, even with all of that revenue net of expense coming from the LLCS customer, and even with the power plant being perfectly sized for the LLCS customer (e.g., ignoring reserve margins), other ratepayers still pay $2.48 billion more over the next 35 years than they would have paid if the new power plant had not been built and the LLCS customer had not been acquired.[21]

The last quote from Staff above is based on its own analysis of its expectation of the impact of large loads on existing customers, purporting to find the potential for significant harm.

Q. Are Staff's observations and the analysis that underlies them right, that is, do they warrant rejection of the Company's proposal?

A. No. Staff's analysis that underlies these observations is plagued by *massive* errors that render the results meaningless. Beyond the things that are demonstrably just flat-out errors, Staff also makes assumptions that are unreasonable that further skew the results. Staff's opinions and observations about the FAC and regulatory lag also contain significant errors and lack critical context about the roles of the FAC and regulatory lag in Missouri's overall regulatory and ratemaking (via the FAC and via base rates and other riders) paradigm. Staff takes a one-sided view that ignores significant regulatory lag that negatively impacts Missouri utilities on a chronic basis and manufactures a narrative out of transient and relatively small effects (in the big picture) that result from the normal and fair operation of the FAC that are offset in other ways through rate cases and other riders. Staff's objections are without merit and should be dismissed by the Commission.

Q. How do you respond to Staff's assertions about the risk analysis you presented in your Direct Testimony?

[21] File No. ET-2025-0184, *Staff Recommendation/Rebuttal* p. 19, ll. 10-14, filed September 5, 2025.

A. It is noteworthy that Staff suggests in the second quote from its Rebuttal Report that I cited above that the analysis I conducted and presented in my Direct Testimony "has no predictive value for the rates Missouri ratepayers should be expected to pay". Staff's statement is conclusory, with no rationale or evidence identifying any errors, flaws, or unreasonable assumptions in my analysis. Staff simply declares the analysis is not reliable as if its assertion makes it so. That said, my analysis was not intended to "predict" future impacts on rates of existing customers. It was a risk analysis that tested the sensitivity of potential impacts that could be expected under different values for key sources of uncertainty about the future. What my analysis does do is provide the Commission with the best information available, grounded in the extremely robust modeling performed for the Company's IRP and the *plans the Company has actually developed to serve large loads*, to have a sense of the scale and direction of potential impacts that are likely to arise from large load service. And as noted, Staff has provided no evidence whatsoever - other than its bare opinion, backed with no facts - that that analysis does not do exactly that. It is also ironic that Staff claims the Company's analysis has no predictive value and then launches into its own analysis of a somewhat similar (but far less robust) nature to try to predict future rate impacts (or "harm", as Staff calls it) on existing customers from large load service.

Q. You have already characterized Staff's analysis multiple times in this testimony as being riddled with, or plagued by, massive errors that render it meaningless. Please explain the flaws you have identified in Staff's analysis.

A. Straight to the punchline, Staff makes simple errors that *skew its results by literally billions of dollars* that when corrected, demonstrate that under all but one unlikely scenario, adding large load customers will in fact provide significant unearned *benefits* to other customers (that is, large load customers will likely provide a significant subsidy to them based on Staff's analysis as corrected). When further corrected for unreasonable assumptions, even the last "worst case" scenario demonstrates the likelihood that large load customer impacts on existing customers are essentially neutral or even provide modest benefits for all customers.

Q. What is Staff's first error?

A. By far the largest single error is Staff's calculation of the revenues that would be provided by large load customers under the Company's proposal. And the error is egregious and very elementary. Staff's calculation of large load revenues included the application of the demand charge, which is stated in dollars per kilowatt in the Company's tariff, to customer demand stated in megawatts. Megawatts are different from kilowatts by a factor of one thousand, meaning that Staff understated the demand charge revenues that will arise from large load service by *1,000 times,* meaning that Staff's analysis assumes large load customer demand revenues would be 1/1000th of what they would actually be. I'll illustrate the error with screenshots directly from Staff witness Sarah Lange's workpapers which tie to the figures provided in the Staff Rebuttal Report.

Figure 1 – Lange Workpaper (500 MW Tab) Calculation of Summer Demand Determinant for Staff's Net Harm Analysis[22]

SUM | =E47*4

	A	B	C	D	E	F
46						
47		MW:	100		500	
48	LPS	Load Factor:	100%		85%	
49	Customer Charge	$ 412.66	12	$ 4,952	12	$ 4,952
50	LIPP	$ 291.99	12	$ 3,504	12	$ 3,504
51	Energy Charge - Summer	$ 0.04060	292,000,000	$ 11,855,200	1,241,000,000	$ 50,384,600
52	Energy Charge - Winter	$ 0.03710	584,000,000	$ 21,666,400	2,482,000,000	$ 92,082,200
53	Demand Charge - Summer	$ 23.90	400	$ 9,560	=E47*4	$ 47,800
54	Demand Charge - Winter	$ 10.63	800	$ 8,504	4000	$ 42,520
55		Revenue:		$ 33,548,120		$ 142,565,576
56		Average $/kWh:		$ 0.03830		$ 0.03829
57						
58						

Figure 1 shows Staff's calculation of retail revenues across the four summer months as defined in Ameren Missouri's tariff from hypothetical 100 MW and 500 MW customers Staff used in its analysis of purported harm from large load service from its workpaper titled "CONFIDENTIAL – General Workbook" on the tab called "500 MW." Note the formula that is activated in cell E53 shows the demand as 500 being multiplied by 4. Note also the label (which I have circled for convenience) in cell B47 clearly indicating the units of *MW* for this customer we know to be 500 MW, as also described in Staff's Rebuttal Report. The multiplication by 4 (see formula bar at the top of Figure 1) is intended to come up with the Summer revenues for a given calendar year from this customer, with 4 being the appropriate multiplier because there are 4 summer months per year under Ameren Missouri's tariffs, and line 53, as the label indicates, is calculating the impact of the Summer seasonal demand charge. Figure 2 below will show the same portion of the same workpaper, but in this figure with the formula highlighted from cell F53, illustrating that that cell is multiplying the total summer demand from cell E53 by the summer demand rate

[22] This figure, along with all other figures that depict Staff's workpapers, is also contained in Schedule SMW-S1 to this testimony but in a larger format for greater ease of reference.

in cell B53 in order to produce a total Summer seasonal demand charge revenue for the hypothetical large load customer.[23]

Figure 2 – Lange Workpaper Calculation of Summer Demand Revenue for Staff's Net Harm Analysis

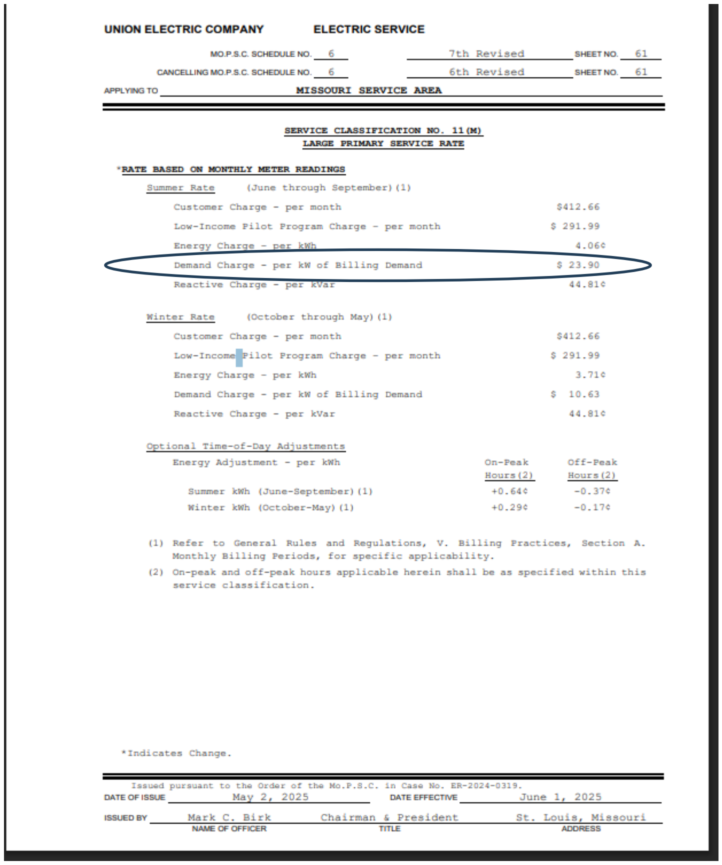
SUM =E53*$B53

	A	B	C	D	E	F
46						
47		MW:	100		500	
48	LPS	Load Factor:	100%		85%	
49	Customer Charge	$ 412.66	12	$ 4,952	12	$ 4,952
50	LIPP	$ 291.99	12	$ 3,504	12	$ 3,504
51	Energy Charge - Summer	$ 0.04060	292,000,000	$ 11,855,200	1,241,000,000	$ 50,384,800
52	Energy Charge - Winter	$ 0.03710	584,000,000	$ 21,666,400	2,482,000,000	$ 92,082,200
53	Demand Charge - Summer	$ 23.90	400	$ 9,560	2000	=E53*$B53
54	Demand Charge - Winter	$ 10.63	800	$ 8,504	4000	$ 42,520
55		Revenue:		$ 33,548,120		$ 142,565,576
56		Average $/kWh:		$ 0.03830		$ 0.03829
57						

Figure 3 below shows the Company's Rate 11(M) tariff,[24] clearly indicating that the demand charge of $23.90 shown in cell B53 is stated in the Company's Commission-approved tariff in units of dollars per *kilowatt* (kW).

[23] The same error exists in the calculation of the Winter demand revenue, such that over the course of the annual period being modeled, all 12 months' demand revenue are similarly understated.
[24] Which is the rate the Company proposes for large load customers, with certain added provisions in a new Section 5 in that tariff, such as minimum demand, term, etc.

Figure 3 – Rate 11(M) Tariff Screenshot



UNION ELECTRIC COMPANY ELECTRIC SERVICE

MO.P.S.C. SCHEDULE NO. 6 7th Revised SHEET NO. 61
CANCELLING MO.P.S.C. SCHEDULE NO. 6 6th Revised SHEET NO. 61
APPLYING TO MISSOURI SERVICE AREA

SERVICE CLASSIFICATION NO. 11(M)
LARGE PRIMARY SERVICE RATE

*RATE BASED ON MONTHLY METER READINGS

Summer Rate (June through September)(1)

Customer Charge - per month	$412.66
Low-Income Pilot Program Charge - per month	$ 291.99
Energy Charge - per kWh	4.06¢
Demand Charge - per kW of Billing Demand	$ 23.90
Reactive Charge - per kVar	44.81¢

Winter Rate (October through May)(1)

Customer Charge - per month	$412.66
Low-Income Pilot Program Charge - per month	$ 291.99
Energy Charge - per kWh	3.71¢
Demand Charge - per kW of Billing Demand	$ 10.63
Reactive Charge - per kVar	44.81¢

Optional Time-of-Day Adjustments

Energy Adjustment - per kWh	On-Peak Hours(2)	Off-Peak Hours(2)
Summer kWh (June-September)(1)	+0.64¢	-0.37¢
Winter kWh (October-May)(1)	+0.29¢	-0.17¢

(1) Refer to General Rules and Regulations, V. Billing Practices, Section A. Monthly Billing Periods, for specific applicability.
(2) On-peak and off-peak hours applicable herein shall be as specified within this service classification.

*Indicates Change.

Issued pursuant to the Order of the Mo.P.S.C. in Case No. ER-2024-0319.
DATE OF ISSUE May 2, 2025 DATE EFFECTIVE June 1, 2025
ISSUED BY Mark C. Birk Chairman & President St. Louis, Missouri
NAME OF OFFICER TITLE ADDRESS

What Ms. Lange should have done is multiply the per kW demand charge by *kWs*, so that the calculation of demand revenue for each month would be based on 500,000 kW times $23.90 per kW for the summer months and times $10.63 per kW for the winter months.

Correcting this error is simple as one only needs to enter the hypothetical customer's load in *kilowatts* into cell E47,[25] which I have done in Figure 4.

[25] I made only this one change to the original workpaper plus I changed the formulas in cells E51 and E52 to remove the multiplication by 1,000, since Staff's workpaper had correctly converted the *energy* billing determinant into kilowatt-hours. When I state the demand value in kilowatts, the workpaper's formulas produce kWhs of energy so multiplying the value of 500 by 1,000 is no longer necessary.

Figure 4 – Staff's Workpaper Corrected for Grossly Understated Large Load Customer Demand

F53 =E53*$B53

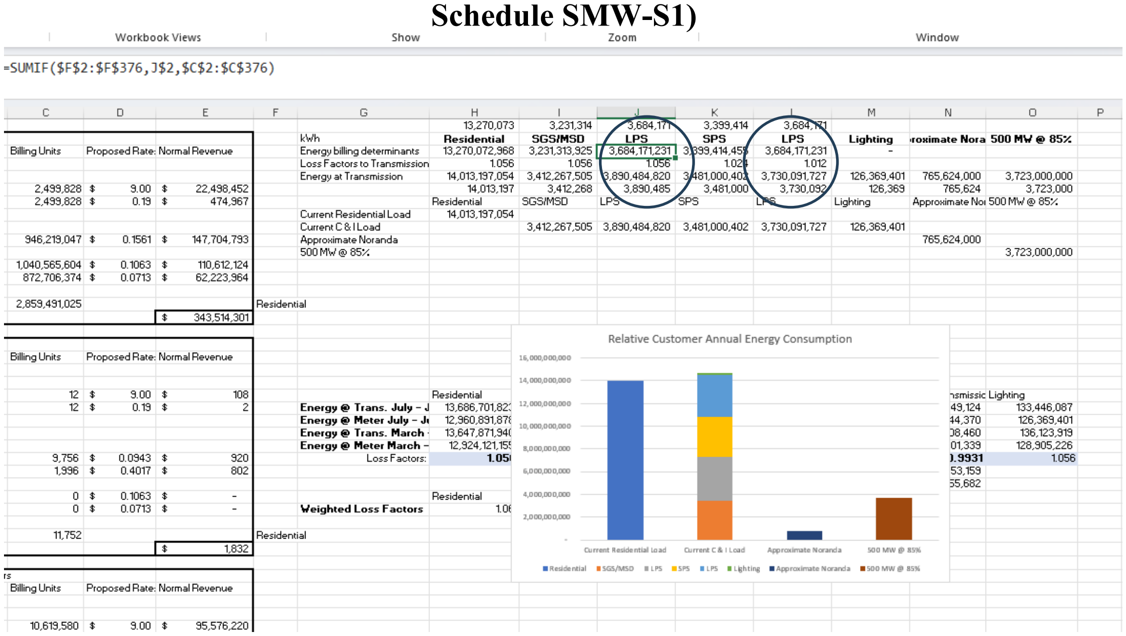
	A	B	C	D	E	F
47		kW	100		500000	
48	LPS	Load Factor:	100%		85%	
49	Customer Charge	$ 412.66	12	$ 4,952	12	$ 4,952
50	LIPP	$ 291.99	12	$ 3,504	12	$ 3,504
51	Energy Charge - Summer	$ 0.04060	292,000,000	$ 11,855,200	1,241,000,000	$ 50,384,600
52	Energy Charge - Winter	$ 0.03710	584,000,000	$ 21,666,400	2,482,000,000	$ 92,082,200
53	Demand Charge - Summer	$ 23.90	400	$ 9,560	2000000	$ 47,800,000
54	Demand Charge - Winter	$ 10.63	800	$ 8,504	4000000	$ 42,520,000
55		Revenue:		$ 33,548,120		$ 232,795,256
56		Average $/kWh:		$ 0.03830		$ 0.06253

As Figure 4 shows, with the correct units for the customer demand, the correct level of annual revenue from this customer increases from Staff's original and incorrect calculation of $142.6 million (see cell F55 in Figures 1 and 2 above) to a corrected value of $232.8 million (also cell F55 in Figure 4). The large load customer revenue Staff used for its analysis is inaccurate, based on nothing but a sloppy error, by *$90 million per year*, or said another way, was *understated by 39%.* It's also noteworthy that the calculation of "Average $/kWh" in row 56 of these screenshots shows that Staff's original revenue calculation (Figure 1) resulted in an average large load revenue per kilowatt hour of approximately 3.8 cents, while the corrected value is approximately 6.3 cents. It is somewhat stunning that the Staff would make an error of this magnitude given (a) how elementary it is that a per kW demand charge must be multiplied by kWs, and (b) the fact that a 3.8 cent per kWh average rate is far below the Company's Large Primary Service ("LPS") rate, with which Staff (and Ms. Lange specifically) should be quite familiar since it was just set in the Company's last rate case concluded earlier this year.

Q. What is the second error?

A. The second error I will highlight is the least impactful of those I will discuss, but I address it next because it has a compounding impact with the next larger error that I will discuss. In the same workpaper I discussed in Figures 1, 2, and 4 above, but this time on the tab called "energy", Staff witness Lange performs some calculations of the Company's total *existing* retail load based on information from the Company's last rate case (File No. ER-2024-0139). However, in aggregating the loads of the various rate classes, Staff, I expect inadvertently, included the load of the LPS rate class in the calculation twice, and failed to include the Large General Service ("LGS") class's load at all. Figure 5 below is a screenshot of the workpaper tab in question:

Figure 5 – Staff Calculation of Ameren Missouri Total Retail Sales (See also Schedule SMW-S1)

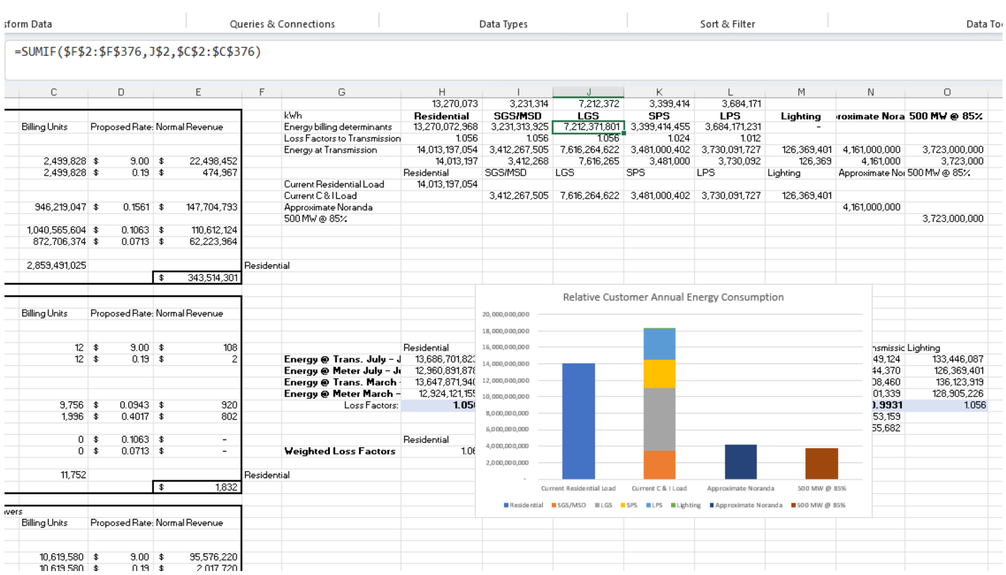


Note in Figure 5 that the LPS class label appears over two different columns (circled in the image), and the LGS class label does not appear at all. Also note in the formula bar shown near the top of the screenshot, that the formula that is calculating the highlighted cell ("J3") is referencing cell J2 as a part of the calculation. The SUMIF formula in Microsoft Excel[26] adds up the values in all of the cells in the referenced range

[26] All of the workpapers I reference are Excel files.

where a corresponding cell (in a range also defined in the formula) meets a certain condition. In this instance, the cell is adding up all of the values in Column C where the corresponding value in Column F contains the Rate Class name that matches the value in cell J2 (in this case, the LPS rate class). The total load reported in cells J3 and L3 in this screenshot are identical, validating the fact that the LPS class is double counted and as noted, there is no column or value for the LGS class at all. A corrected workpaper is shown below in Figure 6 below, where the only change I made to Ms. Lange's original workpapers was to change the value in cell J2 to say "LGS", to remove the double counting of LPS load and to substitute for the duplicated LPS load in that cell the missing LGS load from the rate case. In this correction, I will also correct the figure related to the historical load of the Noranda aluminum smelter, which Staff reported as 95 MW, but which was actually approximately 500 MW[27] – the same size (at least with respect to demand) as the hypothetical large load customer in Staff's examples.

Figure 6 – Corrected Retail Load Calculation from Staff Workpaper



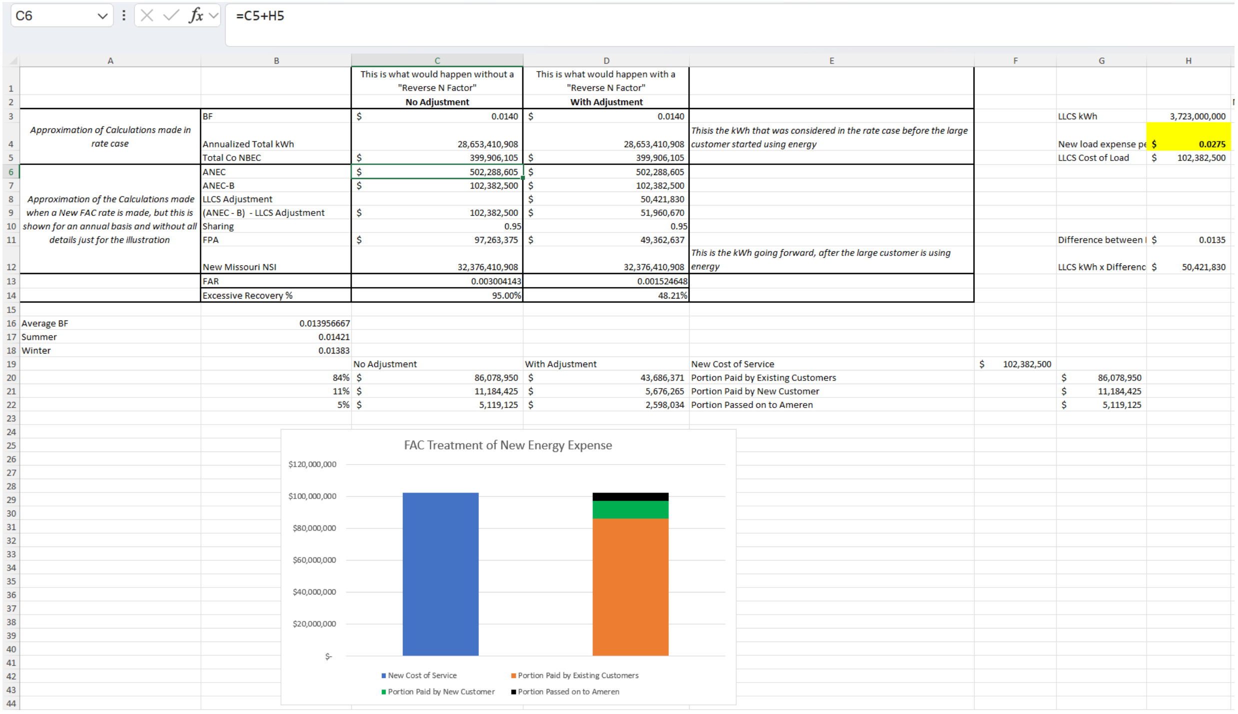
[27] Ms. Lange herself corrected this error on the witness stand during the Evergy evidentiary hearing.

Note that these screenshots also include an image of the graph that Staff included on page 2 of its Rebuttal Report, which reflected these errors. Figure 5 contains the graph as originally included in the Rebuttal Report and Figure 6 contains a corrected version of the graph. The impacts of this correction also flow onto the tab of this workpaper that I previously referenced, called "500 MW," and I will return to that tab to illustrate an additional error of significance in Staff's analysis. The impact of correcting the double counting of LPS and omission of LGS load will flow into the next correction I make as well.

Q. Please discuss this third error.

A. Staff's FAC calculations are erroneous and misstate the large load impact of the FAC on existing customers by a substantial amount. The illustration of this error will also be referenced in my later testimony in the section addressing Staff and OPC's inaccurate and misleading contentions about the FAC. Returning to the 500 MW tab of the same workpaper that I have been discussing (the tab shown in my Figures 1, 2 and 4), I will now look at the section that contains FAC-related calculations associated with this hypothetical 500 MW customer. The first screenshot, shown below in Figure 7, shows the relevant section of the workpaper as Staff submitted to the parties via EFIS.

Figure 7 – Staff FAC Workpaper Calculations



C6 =C5+H5

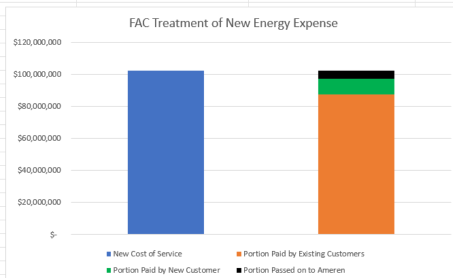
	A	B	C	D	E	F	G	H
1			This is what would happen without a "Reverse N Factor"	This is what would happen with a "Reverse N Factor"				
2			**No Adjustment**	**With Adjustment**				
3	*Approximation of Calculations made in rate case*	BF	$ 0.0140	$ 0.0140			LLCS kWh	3,723,000,000
4		Annualized Total kWh	28,653,410,908	28,653,410,908	*Thisis the kWh that was considered in the rate case before the large customer started using energy*		New load expense pe	$ **0.0275**
5		Total Co NBEC	$ 399,906,105	$ 399,906,105			LLCS Cost of Load	$ 102,382,500
6	*Approximation of the Calculations made when a New FAC rate is made, but this is shown for an annual basis and without all details just for the illustration*	ANEC	$ 502,288,605	$ 502,288,605				
7		ANEC-B	$ 102,382,500	$ 102,382,500				
8		LLCS Adjustment		$ 50,421,830				
9		(ANEC - B) - LLCS Adjustment	$ 102,382,500	$ 51,960,670				
10		Sharing	0.95	0.95				
11		FPA	$ 97,263,375	$ 49,362,637			Difference between I	$ 0.0135
12		New Missouri NSI	32,376,410,908	32,376,410,908	*This is the kWh going forward, after the large customer is using energy*		LLCS kWh x Differenc	$ 50,421,830
13		FAR	0.003004143	0.001524648				
14		Excessive Recovery %	95.00%	48.21%				
15								
16	Average BF	0.013956667						
17	Summer	0.01421						
18	Winter	0.01383						
19			No Adjustment	With Adjustment	New Cost of Service	$ 102,382,500		
20		84%	$ 86,078,950	$ 43,686,371	Portion Paid by Existing Customers		$ 86,078,950	
21		11%	$ 11,184,425	$ 5,676,265	Portion Paid by New Customer		$ 11,184,425	
22		5%	$ 5,119,125	$ 2,598,034	Portion Passed on to Ameren		$ 5,119,125	

Next, I will show Figure 8, which is the same workpaper, but I have made the correction to the total load that I discussed previously related to the double counting of the LPS class and the omission of the LGS class (see Figures 5 and 6 and the related discussion). I made this change by changing cell J2 from the "energy" tab that I discussed previously to show "LGS" instead of "LPS". The updates flow through this calculation, and the screenshot below shows this workpaper section with the impacts of this correction (I changed nothing else in the original workpaper).

Figure 8 – Staff FAC Workpaper Calculation with First Correction Related to Total Retail Sales

C6 =C5+H5

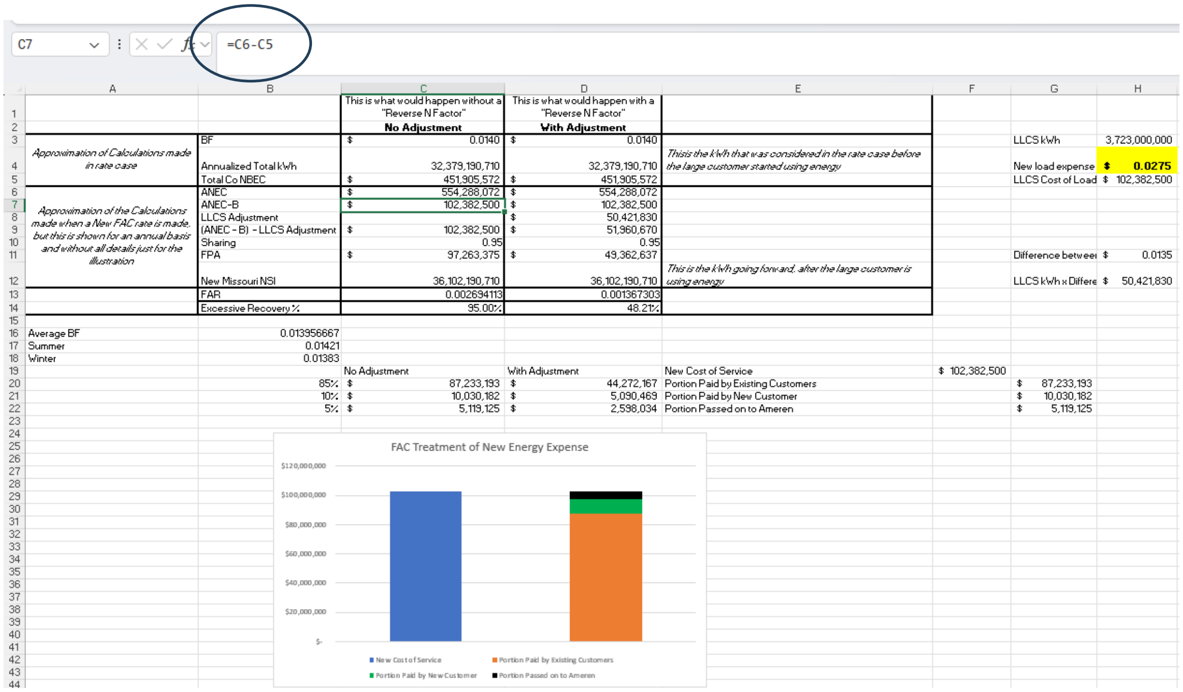
	A	B	C	D	E	F	G	H
1			This is what would happen without a "Reverse N Factor"	This is what would happen with a "Reverse N Factor"				
2			**No Adjustment**	**With Adjustment**				
3	*Approximation of Calculations made in rate case*	BF	$ 0.0140	$ 0.0140			LLCS kWh	3,723,000,000
4		Annualized Total kWh	32,379,190,710	32,379,190,710	*Thisis the kWh that was considered in the rate case before the large customer started using energy*		New load expense pe	$ **0.0275**
5		Total Co NBEC	$ 451,905,572	$ 451,905,572			LLCS Cost of Load	$ 102,382,500
6	*Approximation of the Calculations made when a New FAC rate is made, but this is shown for an annual basis and without all details just for the illustration*	ANEC	$ 554,288,072	$ 554,288,072				
7		ANEC-B	$ 102,382,500	$ 102,382,500				
8		LLCS Adjustment		$ 50,421,830				
9		(ANEC - B) - LLCS Adjustment	$ 102,382,500	$ 51,960,670				
10		Sharing	0.95	0.95				
11		FPA	$ 97,263,375	$ 49,362,637			Difference between l	$ 0.0135
12		New Missouri NSI	36,102,190,710	36,102,190,710	*This is the kWh going forward, after the large customer is using energy*		LLCS kWh x Differenc	$ 50,421,830
13		FAR	0.002694113	0.001367303				
14		Excessive Recovery %	95.00%	48.21%				
15								
16	Average BF	0.013956667						
17	Summer	0.01421						
18	Winter	0.01383						
19			No Adjustment	With Adjustment	New Cost of Service	$ 102,382,500		
20		85%	$ 87,233,193	$ 44,272,167	Portion Paid by Existing Customers		$ 87,233,193	
21		10%	$ 10,030,182	$ 5,090,469	Portion Paid by New Customer		$ 10,030,182	
22		5%	$ 5,119,125	$ 2,598,034	Portion Passed on to Ameren		$ 5,119,125	



To understand the impact of the third error, I would direct the reader to the activated cell in Figure 8, cell C6 (with an outlined border indicating it as the active cell in Excel). In this cell the formula adds the value from cell C5, which is labeled as the "Total Co NBEC", which represents, in this hypothetical, the total net base energy cost of the Company to serve its existing retail load prior to the addition of a large load customer, and which appears to stand in for the Actual Net Energy Cost ("ANEC") of that existing retail load for a hypothetical year-long Accumulation Period, and the value from cell H5, which is labeled as "LLCS Cost of Load" in cell G5. The obvious intent of the activated cell C6, which is labeled as simply ANEC, is to determine the *new* ANEC for this hypothetical year-long Accumulation Period considering the full retail customer base *including* a new large load customer.

Next, let's look at Figure 9, which will again represent the same section of workpaper, but this time highlighting the formula in a different cell.

Figure 9 – Staff Workpaper as Corrected – 2nd View

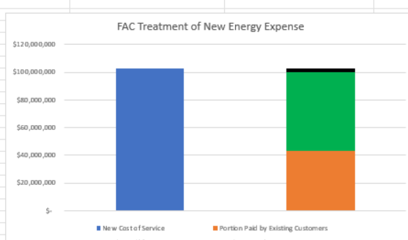


In Figure 9, the formula shown in the formula bar (circled) relates to the active cell – cell C7, which is denoted by the outlined border. That formula, based on the row labeling, is calculating ANEC – B, which is the key formula in the FAC tariff that will determine the Fuel Adjustment Rate ("FAR") that will be paid by retail customers since rates paid by customers under the FAC cover only the difference between ANEC and B. Note that the first cell referenced in this formula – C6 – is the cell that I just discussed, which calculates the ANEC value for this hypothetical Accumulation Period *including* the new large customer load. Now let's look at the second cell referenced in this formula – cell C5, which, if the formula is calculating ANEC – B as the label indicates, and cell C6 is the ANEC, means that cell C5 must be (and is) the "B" term in the FAC. However, Staff has made a mistake because cell C5, as was discussed previously, is the NBEC[28] for the retail load *as it existed prior to the addition of the large load customer* yet this entire calculation, according to Staff, includes the large load customer load. This means that the formulaic application of ANEC – B modeled by Staff is clearly mismatching, by *including* the impact of the new large load customer on the determination of ANEC, but *excluding* the large load customer from the determination of B. This mismatch can be corrected by incorporating the impact of the large load on factor B within this cell C7, by subtracting the product of the large load kWh in cell H3 and the BF ("Base Factor") from cell C3. Figure 10 below shows a screenshot of the workpaper with this correction and also including the correction I made to the workpaper in Figure 8.[29]

Figure 10 – Corrected Calculation of ANEC – B in Staff Workpaper FAC Calculations

C7 =C6-C5-H3*C3

	A	B	C	D	E	F	G	H
1			This is what would happen without a "Reverse N Factor"	This is what would happen with a "Reverse N Factor"				
2			**No Adjustment**	**With Adjustment**				
3	*Approximation of Calculations made in rate case*	BF	$ 0.0140	$ 0.0140			LLCS kWh	3,723,000,000
4		Annualized Total kWh	32,379,190,710	32,379,190,710	*This is the kWh that was considered in the rate case before the large customer started using energy*		New load expense	**$ 0.0275**
5		Total Co NBEC	$ 451,905,572	$ 451,905,572			LLCS Cost of Load	$ 102,382,500
6	*Approximation of the Calculations made when a New FAC rate is made, but this is shown for an annual basis and without all details just for the illustration*	ANEC	$ 554,288,072	$ 554,288,072				
7		ANEC-B	$ 50,421,830	$ 50,421,830				
8		LLCS Adjustment		$ 50,421,830				
9		(ANEC - B) - LLCS Adjustment	$ 50,421,830	$ -				
10		Sharing	0.95	0.95				
11		FPA	$ 47,900,739	$ -			Difference betwee	$ 0.0135
12		New Missouri NSI	36,102,190,710	36,102,190,710	*This is the kWh going forward, after the large customer is using energy*		LLCS kWh x Differe	$ 50,421,830
13		FAR	0.00132681	0				
14		Excessive Recovery %	95.00%	0.00%				
15								
16	Average BF	0.013956667						
17	Summer	0.01421						
18	Winter	0.01383						
19			No Adjustment	With Adjustment	New Cost of Service	$ 102,382,500		
20		85%	$ 42,961,026	$ -	Portion Paid by Existing Customers		$ 42,961,026	
21		113%	$ 56,900,383	$ -	Portion Paid by New Customer		$ 56,900,383	
22		5%	$ 2,521,092	$ -	Portion Passed on to Ameren		$ 2,521,092	



[28] In this case the NBEC is standing in for the tariff formula BF x S_{AP}, and is indeed calculated as such in this workpaper.

[29] I've also made the same correction in column D. Further, I've adjusted the formula in cell C21 to recognize that through the reflection of the BF in base rates, the large load customer implicitly contributed revenues to cover a portion of the increase in costs incurred to serve the large load customer.

When one compares the value in cell C7 labeled ANEC – B in Figure 10 that includes the necessary corrections to Staff's errors to the same cell in Figure 7 (Staff's original and incorrect workpaper), we see that this error resulted in an inflated estimate of the large load customer addition impact of *over $50 million* for the hypothetical Staff depicted. And this huge error perpetuates through Staff's "net harm" calculation for every single year in the four-year interval that Staff assumes between the time the customer initiates service until the time that their revenues are reflected in base rates set in a future general rate case.[30]

Q. Are there any additional errors in Staff's analysis of claimed "harm" from adding large load customers?

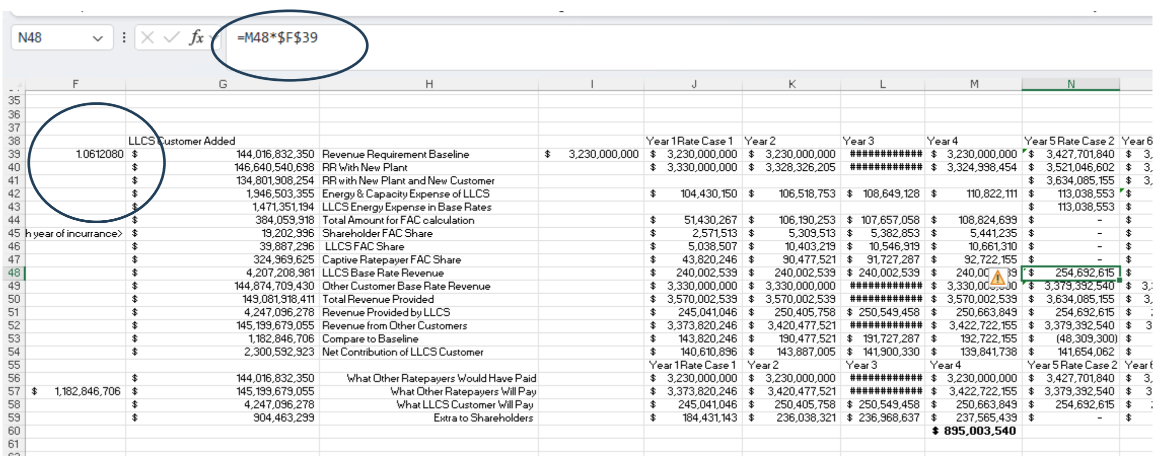
A. Yes, there are. On the "Regulatory Lag" tab of the same Staff workpaper I have discussed in connection with Figures 1, 2 and 4 - 10, Staff models many interactive effects of hypothetical rate cases and escalating costs and revenues over time. On that tab, Staff uses an escalation factor to reflect increases in the base rate revenues that would be paid by large load customers over time – revenues that offset the revenue requirement to the benefit of existing customers (and reduce any perceived or actual harm to them). Here too, Staff makes an error (together with using unreasonable assumptions) in calculating the increases in large load revenues over time, which all serve to *understate* future large load customer revenues and thus inaccurately increase the calculated "harm" to existing customers. I will focus only on the error for now, just to show the impact on Staff's

[30] The FAC calculations in my screenshot do not directly link to the net harm analysis, and therefore I had to edit additional cells to reflect this effect properly in the remainder of Staff's analysis. Specifically, I added the value that results from taking the product of the large load kWh and the BF, the same thing that I built into the formula in the screenshot in Figure 10, to cells J43:M43 on the "Regulatory Lag" tab of the workbook, and also to the same cells on the "Perpetual Customer" tab of the workbook.

calculation of correcting actual mechanical execution errors in the workpaper that flowed into Staff's Rebuttal Report, and will refrain for the moment addressing the unreasonable assumptions, since, while I think it will be self-evident to folks that Staff's assumptions are unreasonable, there is at least some subjectivity in what more reasonable assumptions would be.

Figure 11 below is a screenshot of the section of the workpaper tab that I just referenced that is impacted by this issue, with the active cell set to the cell where the large load revenue is calculated after the first rate case that is concluded following the initiation of the large load customer's service.

Figure 11 – Staff Workpaper of Cost and Revenue Impacts of Large Load Addition Over Time


N48 =M48*$F$39

	F	G	H	I	J	K	L	M	N	
35										
36										
37										
38		LLCS Customer Added			Year 1 Rate Case 1	Year 2	Year 3	Year 4	Year 5 Rate Case 2	Year 6
39	1.0612080	$ 144,016,832,350	Revenue Requirement Baseline	$ 3,230,000,000	$ 3,230,000,000	$ 3,230,000,000	############	$ 3,230,000,000	$ 3,427,701,840	$ 3,
40		$ 146,640,540,698	RR With New Plant		$ 3,330,000,000	$ 3,328,326,205	############	$ 3,324,998,454	$ 3,521,046,602	$ 3,
41		$ 134,801,908,254	RR with New Plant and New Customer						$ 3,634,085,155	$ 3,
42		$ 1,946,503,355	Energy & Capacity Expense of LLCS		$ 104,430,150	$ 106,518,753	$ 108,649,128	$ 110,822,111	$ 113,038,553	$
43		$ 1,471,351,194	LLCS Energy Expense in Base Rates						$ 113,038,553	$
44		$ 384,059,918	Total Amount for FAC calculation		$ 51,430,267	$ 106,190,253	$ 107,657,058	$ 108,824,699	$ -	$
45	h year of incurrance>	$ 19,202,996	Shareholder FAC Share		$ 2,571,513	$ 5,309,513	$ 5,382,853	$ 5,441,235	$ -	$
46		$ 39,887,296	LLCS FAC Share		$ 5,038,507	$ 10,403,219	$ 10,546,919	$ 10,661,310	$ -	$
47		$ 324,969,625	Captive Ratepayer FAC Share		$ 43,820,246	$ 90,477,521	$ 91,727,287	$ 92,722,155	$ -	$
48		$ 4,207,208,981	LLCS Base Rate Revenue		$ 240,002,539	$ 240,002,539	$ 240,002,539	$ 240,00[illegible]39	$ 254,692,615	$
49		$ 144,874,709,430	Other Customer Base Rate Revenue		$ 3,330,000,000	$ 3,330,000,000	############	$ 3,330,00[illegible]00	$ 3,379,392,540	$ 3,
50		$ 149,081,918,411	Total Revenue Provided		$ 3,570,002,539	$ 3,570,002,539	############	$ 3,570,002,539	$ 3,634,085,155	$ 3,
51		$ 4,247,096,278	Revenue Provided by LLCS		$ 245,041,046	$ 250,405,758	$ 250,549,458	$ 250,663,849	$ 254,692,615	$
52		$ 145,199,679,055	Revenue from Other Customers		$ 3,373,820,246	$ 3,420,477,521	############	$ 3,422,722,155	$ 3,379,392,540	$ 3
53		$ 1,182,846,706	Compare to Baseline		$ 143,820,246	$ 190,477,521	$ 191,727,287	$ 192,722,155	$ (48,309,300)	$
54		$ 2,300,592,923	Net Contribution of LLCS Customer		$ 140,610,896	$ 143,887,005	$ 141,900,330	$ 139,841,738	$ 141,654,062	$
55					Year 1 Rate Case 1	Year 2	Year 3	Year 4	Year 5 Rate Case 2	Year 6
56		$ 144,016,832,350	What Other Ratepayers Would Have Paid		$ 3,230,000,000	$ 3,230,000,000	############	$ 3,230,000,000	$ 3,427,701,840	$ 3,
57	$ 1,182,846,706	$ 145,199,679,055	What Other Ratepayers Will Pay		$ 3,373,820,246	$ 3,420,477,521	############	$ 3,422,722,155	$ 3,379,392,540	$ 3
58		$ 4,247,096,278	What LLCS Customer Will Pay		$ 245,041,046	$ 250,405,758	$ 250,549,458	$ 250,663,849	$ 254,692,615	$
59		$ 904,463,299	Extra to Shareholders		$ 184,431,143	$ 236,038,321	$ 236,968,637	$ 237,565,439	$ -	$
60								**$ 895,003,540**		
61										

The row label for line 48 indicates that this is Staff's calculation of LLCS Base Rate Revenue. Cell N48 shows the calculation of this revenue in Year 5, which is labeled as a rate case year (confirming Staff is contemplating a 4-year rate case cycle in this analysis) where the large load revenue would be subject to increase based on an assumed escalation rate, which the circled formula in the formula bar shows is coming from cell F39. The formula in Cell F39 is "=1.02^3". This is the formula for compound annual growth. It is clear from this formula that Staff assumed a 2% compound annual growth in utility rates that would be implemented in each rate case. That compounding, however, must be performed for the actual number of years of escalation – the number of years from rate case to rate case. The number 3 that is being applied as an exponent to the 1.02 factor in this cell indicates that Staff is applying only *three* years' worth of compounding between rate cases, but Staff assumed that those rate cases would occur at *four*-year intervals. So while it is very clear that Staff used a 2% rate escalation assumption, Staff mismatched the number of years in its compound annual growth formula with the number of years over which that growth would be actually experienced. Correcting the exponent in the formula in cell F39 to be 4[31], which matches with the rate case timing assumption, would increase the factor that is applied to large load revenues from approximately 1.061 to 1.082.[32] This compounding effects every future rate case in Staff's modeling. So over time, the large load revenues Staff models are quite significantly lower than they should be due to the errantly understated growth rate in retail rate levels. In fact, the revenues that Staff actually modeled by including this error only grow at a compound annual growth rate of 1.49% instead of the 2% that Staff assumed.

Q. Was that the last error that over- or mis-stated the "harm" Staff claimed?

A. No. The next error I will discuss is an error of omission. Staff (and OPC) have fixated on impacts that large load customers will have on other customers through the FAC as evidenced by pages and pages of testimony on the topic. And yet somehow both managed to completely ignore any impacts that large load customers will have on other

[31] I made the same correction to the same calculation on the "Perpetual Customer" tab.
[32] 1.061 is 1.02^3 (three years) and 1.082 is 1.02^4 (four years).

customers through any of the Company's *other* riders. I would expect large load customers to be likely to opt out of Rider EEIC (energy efficiency) as they are entitled to do by law, and I'll conservatively assume that the Commission approves the Company's requested rule variance that would exempt some large load customers from being impacted by the RESRAM,[33] so it is probably reasonable to ignore those two riders. It is not, however, at all reasonable to contemplate the (transient) impact of large load customers on the FAC while ignoring lasting and long-term impact that large load customers will have in *reducing* existing customers' cost responsibility for the securitization charges associated with the retirement of the Company's Rush Island Energy Center under Rider SUR, which by statute is a mandatory, non-bypassable charge all customers, including large load customers, must pay. Further, there essentially is a finite pool of dollars to be recovered to pay off the securitized utility tariff bonds, so *every dollar* a large load customer pays into Rider SUR represents a dollar that *will not be paid by someone else*. It is also noteworthy that all of the costs of this securitization are associated with the recovery of costs associated with a plant that is already retired today, prior to any large load customer taking service, and therefore large load customers will *never* receive any benefits from. Large load customers will clearly be subsidizing existing customers through Rider SUR, many or most of whom did benefit from Rush Island, by paying down the unrecovered balance from that plant. Staff makes no mention of this fact, and the benefit provided by prospective large load customers to existing customers through Rider SUR.

A reasonable estimate of the impact of this error of omission can be calculated using a pro forma version of the existing Rider SUR rate by taking the Total Securitized Revenue

[33] Renewable Energy Standard Rate Adjustment Mechanism.

Requirement from the currently effective Rider SUR rate and dividing by the billing units for the current Rider SUR rate adjusted for the projected billing units of the 500 MW customer in Staff's hypothetical. The resulting Rider SUR rate from this calculation applied to the annual kWh consumption of the 500-MW customer represents a good estimate of the annual amount of revenue that that customer would contribute through Rider SUR that would directly benefit (or reduce harm for) all existing customers. Working through the math I just described, the 500 MW customer would pay about $4.8 million per year in Rider SUR charges on a persistent basis until the securitized utility tariff bonds have been paid in full. Since Staff's hypothetical does not indicate what year the customer starts service, I'll assume for this analysis that the customer would provide 10 years' worth of Rider SUR contributions based on the fact that the bonds are expected to be fully amortized in 2039. Under this assumption, another approximately $48 million in benefits accrue to all customers as a result of the hypothetical 500 MW large load customer, which neither Staff nor OPC considered.

Q. Was that the only error of omission in Staff's analysis?

A. No, another error of omission in this analysis was explicitly recognized by Staff in a footnote in its Rebuttal Report.[34] Staff ignored the existence of benefits that arise from Accumulated Deferred Income Taxes ("ADIT") related to income from the investment in the plant in its hypothetical analysis. As justification for this omission, Staff's footnote indicated, "as this plant is entirely hypothetical, the complexity of detailed income tax accounting is not reflected."[35]

[34] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 18, footnote 33, filed September 5, 2025.
[35] Id.

This comment is quite striking, as the entirety of Staff's hypothetical analysis is *very* complex, irrespective the fact that this is a hypothetical. That this material revenue requirement element was omitted due to complexity simply doesn't make sense. And while tax concepts are conceptually complex, the calculations needed to quantify this were not particularly complex. In fact, I was able to estimate the impact of ADIT by adding just five rows of calculations to Staff's spreadsheet, which already had dozens of rows of complex formulas that Staff did choose to create. It took about fifteen minutes to do those calculations. There is simply nothing about the hypothetical nature of the calculation that makes it appropriate to ignore the very real benefits that will arise from the beneficial tax treatment related to investment in plant. My calculation indicates that the revenue requirement of the plant over the 35 years of Staff's analysis – and Staff's conclusion about "net harm" - would have been approximately $116 million *less* if Staff had quantified the impact of ADIT that it acknowledges will exist. I provide additional observations later in this testimony about Staff's choices related to ADIT, which consistently seem to inappropriately bias its results in favor of its eventual conclusions.

Q. Are there any other errors that bear mentioning?

A. Yes, and this one cuts the other way, meaning its correction increases the calculated "net harm". But I want to be fair and transparent since I identified it. In this same workpaper, Staff applies the Company's proposed rates to the customer load (as described earlier) using its tariff rate but omitted the impact of the Rider B discount that applies to all customers served at the voltage level at which large load customers will be served. While I won't depict the error as I did the others above, since I would assume Staff isn't going to take issue with correcting its work in favor of its stated conclusions (the

Company will provide the parties with the corrected workpapers discussed herein), the error has about a $9 million (nominal dollars) impact on first year revenues (escalating with the assumed escalation rate over the 35 years Staff modeled). I will include the correction of this error in my calculation of the cumulative impact of all of Staff's errors below.

Q. How does the correction of *all* of these errors – the several where Staff greatly understated large load customer revenues and the one where Staff overstated them - cumulatively impact the conclusions of Staff's "harm" analysis?

A. Correction of them reduces the alleged "harm" to existing customers by billions of dollars and in most (and the most plausible) scenarios Staff examined turns this claimed "harm" into a benefit for (a subsidy of) non-large load customers.

Q. Please explain.

A. Staff originally reports the "punchline" of their analysis in a table on page 21 of its Rebuttal Report. Table 1 below shows a comparison of Staff's original calculations, as reported in its Rebuttal Report, to the corrected values that I have calculated based on a cumulation of the errors identified above. Each row of the table represents the "net harm" under Staff's analytical framework associated with a different scenario created by Staff. I would note that the first two rows are not really relevant to anything, as they represent scenarios where the Company invests in new generation but does not serve any large loads and thereby realize revenues to pay toward the cost of that generation. I include these rows in the interest of completeness since Staff also included these in its Rebuttal Report but dismiss the notion that they have any value for understanding the impact of actually serving large loads. I would also note that the version of this table in Staff's workpaper contains one additional row of data and calculations that Staff omitted from its Rebuttal Report. That row calculated Staff's "net harm" based on a scenario that assumed that the large load customer impact persisted after the first 16 years, meaning the hypothetical customer effectively continued on as a customer in perpetuity (this is the "35 Year" scenario described below). I will include the values for that row in the table as well as the ones that Staff chose to share in its Rebuttal Report. The "16 year" scenario in Staff's table is effectively very much a worst-case scenario, where the customer leaves the system almost immediately following the term of its initial service agreement. The "35 Year" scenario that Staff did calculate in its workpaper but did not include in its Rebuttal Report is likely a more realistic scenario where the customer continues to operate beyond its initial term. I would further note that the version of the table I will present below only corrects actual mechanical errors and omissions in the execution of Staff's model as I outlined them above but does not address unreasonable assumptions that also underlie Staff's calculations and which, if we substituted more reasonable assumptions, would lead to an even greater subsidy *by* large load customers *of* non-large load customers (or far less harm in the one, worst-case scenario). The far-right column labeled "Magnitude of Error Impact" shows the cumulative dollar value of Staff's errors on that scenario, where a negative number is a reduction in the calculated "harm". Note that a positive number in either of the first two columns represent costs borne by non-large load customers, a negative number in those columns represents a benefit to non-large load customers.

Table 1 – Staff's Original Net Harm Analysis vs. Analysis Correcting Staff Errors[36]

Staff Scenario	Staff's Original Harm	Corrected Benefit/Harm	Magnitude of Staff Errors Impact
Net Harm from Adding Plant (Perfect Ratemaking)	$2,564,049,937	$2,448,155,953[37]	-$115,893,984
Net Harm from Plant, with Regulatory Lag	$2,597,536,969	$2,481,642,984[38]	-$115,893,984
Net Harm from Plant & LLCS Customer (16 Year)	$2,481,406,393	$880,916,165	-$1,600,490,228
Net Harm from Plant & LLCS Customer (35 Year)	$1,767,028,232	-$2,895,418,008	-$4,662,446,240
Net Harm with Deferrals & Perfect Ratemaking	$1,434,478,313	-$867,057,895	-$2,301,536,208
Net Harm with Deferrals & Regulatory Lag	$1,473,276,406	-$817,712,628	-$2,290,989,034

The obvious takeaway from the corrections shown in Table 1 is that, in every scenario where large load is present in Staff's analysis except one, the net harm is "negative harm," which could also be characterized as a "benefit" or "subsidy." In these scenarios, there is in fact a *net benefit* to all customers - a benefit of up to approximately *$2.9 billion*. In the scenarios that reflect Staff's proposed deferrals, those deferrals serve to generate subsidies (net benefits that are unearned) for existing customers at the expense of either the large load customer, the Company's shareholders, or both. In the worst-case scenario possible (the scenario where the customer terminates service at 16 years), the net harm as calculated by Staff is reduced by $1.6 billion to a total of approximately $881 million over 35 years – or about $25 million per year, which is in the neighborhood of three-quarters of a percent of the Company's current revenue requirement (with that percent declining over time as the revenue requirement rises).[39]

[36] I have included the first two rows from Staff's Rebuttal Report because Staff included them but those rows are irrelevant because they depict costs for generation purportedly to serve large load customers but account for *no* revenues from large load customers, meaning the generation costs would not be incurred.
[37] This isn't real harm and this scenario is irrelevant – the Company won't build the generation if it doesn't have the large load customers.
[38] This isn't real harm and this scenario is irrelevant – the Company won't build the generation if it doesn't have the large load customers.
[39] And that percentage will decline over time as the revenue requirement increases.

Even more interesting is the fact that, in this one scenario in which the corrected result still represents a modest net harm (averaging less than a percent per year), the net harm occurs more than *a decade and a half into the future,* after the large load termination occurs. That's right - while the assumption in Staff's analysis is that the large load customer ceases taking service after 16 years, the analysis extends out for 35 years, calculating revenue requirement impacts from the plant that continues to exist after the large load customer's termination. It is these late year revenue requirements that represent modeled increases to existing (or perhaps in this instance it is more appropriate to say future) customers. However, there exists a *net benefit* over the duration of the large load customer's service term. The impact on other customers in this "worst case" scenario is *a net benefit of $244 million* during the 16-year term during which the customer takes service, with all of the net harm occurring in the back half of the 35-year period.

And none of this accounts for unreasonable assumptions made by Staff that are skewing even this result toward overstated harm, nor other potential benefits that may further offset any remaining harm or generate incremental benefits. Specifically, unreasonable assumptions and possible upside benefits that are ignored, and the potential impacts of each of these, include:

- Staff assumes utility rates increase at a compound annual growth rate of 2%. I discussed in my Direct Testimony more realistic expectations of annual retail rate growth as being in the 3-5% range. The total net harm in Staff's worst-case scenario is reduced by roughly $300 million per each additional percent of rate growth above Staff's assumed 2%.

- Staff's assumed operations and maintenance expense ("O&M") for the plant built to serve the large load customer appears unreasonably high and seems as though it was set as an arbitrary "plug" to get to the $100 million annual revenue requirement that Staff simply came up with as an assumption but which Staff did not back up with any actual cost basis or other justification at the outset of its analysis.[40] Using a more realistic O&M assumption – an assumption based on another analysis in Staff's workpapers[41] - would reduce the annual O&M by $13 million and reduce the net harm over the 35-year period of analysis by an additional $643 million.

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[40] Staff's response to Data Request 62 issued by the Company basically confirms this, saying "[t]he value represented by $32,846,875 is intended to be generally representative of the net cost of service of operating and maintaining a generation facility for purposes of the illustration discussed in the Report that was not otherwise identified in cells J6:J12. The exact valuation was derived by calculating the sum of the other components in cells J6:J12 and subtracting them from $100,000,000 for purposes of making the illustration more understandable." Staff's response is attached as Schedule SMW-S2.

[41] In Staff's workpaper titled, "Ameren LLCS Other Rate" Staff calculated the Company's total generation gross investment and the other operating costs of that investment in order to determine a unit cost of the various operating costs, per billion dollars of gross investment as a part of its determination of the generation demand charge. Scaling that unit cost down to the $750 million gross investment level Staff assumed for the new generation reflected in its net harm analysis would mean that the annual O&M costs for its hypothetical plant would be closer to $19.6 million rather than the $32.8 million apparent "plug" that Staff used based on its assumption. I utilize this $19.6 million data point as a more reasonable assumption since it is grounded in Staff's own analysis used to develop its rate proposal in this case. I consider it still to be a very conservative assumption (i.e., potentially overstate "harm"). I say it is conservative because using, for example, the O&M assumptions from the Company's IRP for a combined cycle gas turbine would result in an annual O&M expense value more like $14 million for a 500 MW plant like that in Staff's hypothetical.

- Staff assumes a very unlikely and unreasonable rate case cycle of four years between cases. While adjusting Staff's workpaper to model a shorter rate case cycle is beyond the scope of what I could do in the time allotted for surrebuttal, it is reasonable to assume that 2 year rate cases, consistent with recent history and with the Company's anticipated need for capital investment, would likely cut Staff's calculation of the cumulative regulatory lag impact – an additional approximately $50-70 million depending on the scenario - roughly in half.[42]
- Staff makes no allowance for large load customers to subscribe to clean energy programs, which will both meet those customers' needs and preferences, as well as generate incremental revenue to increase net benefits to existing customers. In my Direct Testimony, I estimated the potential for such programs to generate hundreds of millions of dollars of benefits.

Q. Can you estimate the impact of substituting reasonable values for Staff's unreasonable values for *just* the growth in base rates, O&M, and rate case timing assumptions?

A. Yes, Table 2 below replaces the last two columns from Table 1 with two new columns. The first new column shows the "net harm" including all corrections described above, plus the following more reasonable assumptions for the first three bulleted items above:

[42] This estimate of the impact of regulatory lag in Staff's scenarios is based on a comparison of scenarios that are otherwise equivalent, except where Staff provides one of the scenarios based on "perfect ratemaking" and the other scenario based on "with regulatory lag." I suspect due to the complexity of Staff's model, the true impact may be higher, but will conservatively assume this level because it is directly discernable from the data in Staff's workpaper.

- Annual rate increase percentages of 3% rather than 2%, which I still believe be quite conservative,
- Annual O&M for the hypothetical plant Staff modeled in line with the unit costs Staff calculated in the other workpaper I referenced above, and
- Adding back half of the regulatory lag from the lower end of the range I estimated above to assume rate cases occur twice as often as Staff's unreasonable 4-year assumption.

The second column shows the calculation of the impact of the cumulative impact of the corrections and updated, more reasonable, assumptions.

Table 2 – Staff's Original Net Harm Analysis with Corrections and Updated Assumptions

Staff Scenario	Original	Harm/Benefit with Corrections and Updated Assumptions	Magnitude of Staff Errors and Unreasonable Assumptions Impact
Net Harm from Adding Plant (Perfect Ratemaking)	$2,564,049,937	$1,785,728,948	-$778,320,990
Net Harm from Plant, with Regulatory Lag	$2,597,536,969	$1,838,014,346	-$759,522,623
Net Harm from Plant & LLCS Customer (16 Year)	$2,481,406,393	-$35,838,150	-$2,517,244,543
Net Harm from Plant & LLCS Customer (35 Year)	$1,767,028,232	-$5,697,549,586	-$7,464,577,818
Net Harm with Deferrals & Perfect Ratemaking	$1,434,478,313	-$1,850,890,589	-$3,285,368,902
Net Harm with Deferrals & Regulatory Lag	$1,473,276,406	-$1,780,814,166	-$3,254,090,571

As shown by Table 2, even very conservative assumptions (e.g., only 3% retail rate growth) result in no "net harm" and in fact result in large benefits in most scenarios (and in even the worst-case scenario, shows a small benefit to other customers). And if large load customers sign up for Rider RSP-LLC or other clean energy programs it would all serve to increase what is already a *net benefit* of serving this large load customer.

Q. Please summarize your testimony on Staff's analysis of the "net harm" to existing customers from large load service.

A. I've gone on long enough already, so I'll summarize it extremely succinctly. Staff's analysis contains a staggering number of errors that dramatically skewed Staff's results. It also had unreasonable assumptions that further skewed those results. When the errors are corrected and reasonable assumptions are overlaid, Staff's analysis suggests that large load service under the Company's plan will be not only net beneficial, but most likely significantly so. Instead of harming customers by as much as $2.5 billion, the correction of errors alone results in benefits of up to $2.9 billion and updated more reasonable assumptions, suggests that that net benefits could be well over $5 billion.

Q. What is the implication of your conclusions about this testimony?

A. This analysis represents Staff's primary justification for its recommendation to reject the Company's proposal in this case, as well as its rationale for coming up with its own proposal. Given the fact that the analysis no longer even comes close to supporting Staff's conclusions, both the analysis itself and Staff's recommendations based on it must be summarily rejected.

V. STAFF'S RATE DESIGN IS OVERLY COMPLEX FOR LITTLE, IF ANY, BENEFIT

Q. What concerns do you have with the complexity of Staff's large load rate design proposal?

A. As I suggested in my introductory comments, Staff's rate structure is unnecessarily and *extremely* complex. Staff's rate design includes rate values or placeholders for up to *fourteen unique rate elements* that would apply to large load customer bills, including at least *nine brand new discrete charges* above and beyond what other industrial customers' rates reflect, with opaque, obscure, and confusing charge names such as "variable fixed revenue contribution." To my knowledge "variable fixed revenue" is a term of Staff's invention that is not used anywhere in the industry, and which is perplexingly convoluted (i.e., is it variable or is it fixed – those are inherently contradictory). What is a prospective customer supposed to make of this charge?

All of the complexity reflected in Staff's rate structure does little, if anything, to provide benefits to anyone. But it does dramatically reduce the transparency and understandability of the rate offering for prospective customers that are very likely to desire detailed information about the trends, trajectories, and potential risks of each of these very specific costs that will be on each and every one of their bills so that they can model their expected energy costs in the process of making decisions about taking service from a particular utility. In my opinion, Staff's rate would be practically impossible for a prospective customer to model with the level of confidence it would need to invest billions of dollars in Missouri. Staff notes that large load customers are among the most sophisticated of energy consumers, and therefore should be able to understand and contend with the complexity of the rate.[43] While I agree, in general, with the notion that most large load customers are sophisticated energy consumers, in my opinion the complexity of the rate and the difficulty in understanding and modeling its potential impacts would be a red flag for them related to the lack of transparency of energy pricing and the potential for uncertain and unpredictable outcomes.

[43] ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 46, ll. 13-14, filed September 5, 2025.

Q. Is the complexity of Staff's rate proposal consistent with other large load rates you have seen in the industry across jurisdictions?

A. No, it is an obvious outlier. I have reviewed information from large load cases of several utilities. Rate proposals for Evergy, Ameren Missouri, AEP Ohio, Dominion Virginia, Consumers Energy (Michigan), Kentucky Power, Santee Cooper, and Arizona Public Service all rely on the same rate elements for large load base rate charges as their existing industrial rates.[44] A couple of utilities, including Indiana & Michigan Power and Florida Power & Light supplement their existing rate framework with a small number of additional charges for large load customers. One utility, Wisconsin Electric Power, has a more complex large load rate offering but it is predicated on market-based pricing and it still has substantially fewer charges than Staff's rate proposal. Staff's rate design is completely out of step with the industry and that will impact Missouri's competitiveness for the investment of large load customers.

Q. Are there other elements of Staff's rate proposal that introduce unnecessary complexity?

A. Yes. Staff is focused on the idea of requiring large load customers to be served under dedicated commercial pricing nodes ("CP Nodes") that would be separately registered with the utility's regional transmission organization ("RTO"), in the Company's case, Midcontinent Independent System Operator ("MISO"). This is an example of Staff adding tremendous administrative complexity in what appears to be a pursuit of "to the penny" accounting of the impacts of large loads on existing customers. Let's be clear about the standard articulated by SB 4, which requires *reasonable* assurance that no "unjust or

[44] Some of these utilities may introduce a new rider, such as Evergy's Rider SSR in this case, but the base rate charges are the same as existing large load service.

unreasonable" costs be reflected in other customer classes' rates as a result of large load service. That standard, however, does nothing to remotely require "to the penny" tracking of every potential source of cost impacts associated with large load service. The statutory requirement is to "reasonably ensure" a rate that reflects "the customers' representative share of the costs incurred to serve." I am not an attorney, but "reasonably ensur[ing]" that the rate reflects a "representative" share certainly means there is not a requirement to be exact or "to the penny." Furthermore, the existence of the qualifiers "unjust or unreasonable" also in that same sentence in SB 4 necessarily means that there could exist a level of costs (or benefits) that are reflected in other customer classes' rates that would not reach the threshold of being considered unjust and unreasonable. Those words would not be there if there was to be a complete ringfencing of every possible cost down to the penny. It is absolutely the case that utility ratemaking is not a perfect science and that the Commission establishes just and reasonable rates for various classes of service all of the time using various estimates, allocations, and averages that are imperfect, but reasonable. The important thing in establishing the justness and reasonableness is to think critically about factors that can and do have a material impact on rates and use the best information available to ensure that those factors are considered and addressed reasonably in the ratemaking process, including via the Commission's ongoing authority to ensure all rates are just and reasonable as we move through time.

Q. Are RTO level forecasting and energy market imbalance costs likely to be a major determining factor as to whether existing customer rates are unjustly or unreasonably impacted by large load service?

A. No. In the context of potentially billions of dollars of investment in generation that may be accelerated to enable large load service, energy market imbalance (or load forecast deviation) costs – which are costs Staff targets by advocating for a separate CP Node for every large load customer -- are very small and should not even be on the Commission's radar as a place to spend significant effort in this proceeding. Energy market imbalance costs are, relatively speaking, a very small component of the Company's overall revenue requirement. They are not remotely comparable to the costs associated with the scale of investments in new generation that will be accelerated in order to provide large load service. But even if the absolute level of imbalance costs were significant in this context, one would have to have an expectation that the level of imbalance costs attributable to large load customers would be materially and systematically different from the costs associated with all other customers for there to be any potential impact that would even begin to be worth tracking.

Q. Do you have such an expectation (i.e., that imbalance costs will be materially and systematically different for large load customers than for all other customers)?

A. No.

Q. What experience do you base that opinion on?

A. In my first role at Ameren over several years, I had the responsibility for developing the forecasting system that Ameren uses for RTO load forecasting and operating and supervising that system to conduct day-ahead forecasts that were submitted to MISO. I "lived" day-ahead load forecasting inside and out during that time, while developing an understanding of different load types, and the impact on RTO settlement statements of forecast variances (imbalances).

Q. Are large loads likely to have a systematically different average level of imbalance cost (load forecast deviation) than the rest of the system load?

A. While it can depend on the individual load, my overall expectation is that they will not – and that many may drive *down* the average cost of forecast variances for the system as a whole. Particularly the type of high load factor loads that I think are most prevalent among the largest category of customers I see currently seeking large load service: data centers. Such customers will almost certainly design their facilities and systems to achieve high utilization of their equipment, resulting in very high load factors. High load factor customer loads are generally much more predictable and result in relatively lower forecast variance than the system as a whole.

Q. Do you have any experience forecasting high load factor loads?

A. Yes. I developed forecasts for the Noranda aluminum smelter in my forecasting experience, which was an approximately 500 MW, 95% load factor customer. While this occurred the better part of two decades ago and I do not have load forecast statistics at my fingertips today, I can say with a high degree of certainty that inclusion of that load into the same CP Node as the rest of Ameren Missouri's system load *reduced* the average forecast variance and created *benefits* for all customers in the form of lower average forecast deviation costs. In fact, for RTO settlement charges like MISO's revenue sufficiency guarantee charge that are billed based on the total forecast error irrespective of the direction of that error (i.e., the charge is the same whether the load forecast was too high or too low), it is a mathematical certainty that the overall cost for all customers (including the large load customer) will be lowest when aggregating all loads into a single CP Node. In this regard, Staff's call for separate CP Nodes will necessarily *increase* the cost for the entire body of retail customers.

Q. Staff mentions certain conditions or circumstances that they allege may cause large load customers to have higher levels of forecast deviation than the rest of the customer base, including the potential for unpredictable loads like arc furnaces and potential weather sensitivity of cooling loads at data centers. Are these circumstances justification for separate CP Nodes for all large load customers?

A. No. I have personal experience forecasting the load on a day ahead basis for an arc furnace. This is one time in this case that I can say Staff is not wrong, at least in terms of its characterization of the challenge associated with forecasting a load of that type. Arc furnace loads are nearly impossible to forecast on a day ahead basis with a high degree of accuracy. That said, I do not believe that the outside possibility that an arc furnace or similar load could seek service in a utility's service territory should be the over-riding consideration for the entire tariff framework that will serve all large loads, which will initially likely be dominated by data centers, with perhaps some other advanced manufacturers in play as well. It makes no sense to subject all large loads to onerous and complex CP Node requirements out of fear that one difficult to forecast customer will show up. If that occurs, the Company can deal with that circumstance at that time.

As far as weather sensitivity of potential data center loads, that should not be cause for any increase in forecast deviation relative to the highly weather sensitive system load that utilities already forecast every day. Forecasting models are very sophisticated in their treatment of weather sensitivity, and given a good weather forecast, we can be extremely accurate in our forecasts of weather sensitive loads. And a bad weather forecast will negatively impact the forecast of the overall system load every bit as much, or more, than the forecast of a data center. Meaning that the forecast for a data center should not be systematically prone to greater levels of deviation than the rest of the retail customer base. I would simply say that there is absolutely nothing in my quite extensive day ahead load forecasting experience that gives me any reason to believe that energy market imbalance (or load forecast deviation) costs of large load customers should be a noticeable source of cost for anyone. Staff's attempt to impose "to the penny" tracking of this cost is simply yet another administrative burden without any meaningful benefit.

VI. THE COST BASIS OF STAFF'S RATE IS INTERNALLY INCONSISTENT AT BEST, AND TOTALLY LACKING AT WORST, RESULTING IN AN UNREASONABLE RATE FOR LARGE LOAD SERVICE

Q. Setting aside the complexity of the structure of the rates, do you have concerns with how Staff calculated the level of the charges that it proposes to subject large load customers to?

A. Absolutely, in fact, I would use the phrase significant concerns. In several respects Staff's rates lack a proper relationship, and for some charges *any* relationship, to the costs that are or will be reflected in the Company's revenue requirements. Staff's rates simply cannot be said to reflect Ameren Missouri's cost of serving large load customers. It is foundational to utility ratemaking that rates be set in a manner that is intended to allow the utility a reasonable opportunity to recover its prudently incurred costs and earn a reasonable return on the investments it has made to serve customers. That principle manifests itself in rate cases as the determination of the utility's annual revenue requirement - the amount of money that rates should be designed to produce in order to provide the utility with that opportunity - based on a thorough review of that utility's costs. Fairness to customers also dictates that just and reasonable rates should not be knowingly and deliberately set obviously higher than the utility's cost to provide their service, at least without some policy justification (e.g., incentives, sharing of savings, etc.), so as to create a significant likelihood of the utility earning revenues that exceed its revenue requirement. Staff's rate proposal fails to achieve these basic principles.

Q. What about the way Staff creates its rate results in this failure?

A. Staff takes a different approach to establishing each type of charge, with little to no consideration of how those charges interact with each other and thereby *work together* to recover the costs that make up the revenue requirement. And while Staff may argue that they are not making large load rates on an embedded cost basis, but are rather trying to capture some incremental cost of serving large loads instead, the assessment of costs still needs to reasonably reflect the actual costs that are and will be in the Company's revenue requirement, and certainly should not recover the same costs multiple times across multiple different charge types, or reflect arbitrary cost levels or costs that do not exist. If Staff employed its large load methodology to develop rates for all of the Company's retail service classifications, it is a virtual certainty that the sum total of the annual revenues from those charges would be higher, perhaps significantly so, than its cost-based revenue requirement. The piecemeal approach Staff has taken to selecting one basis for this charge over here, and a different basis for that charge over there is inconsistent, at best, and is entirely lacking in cost basis at worst. I will illustrate this by walking through some of the most obvious examples of the inaccurate and inconsistent ratemaking reflected in Staff's approach, starting with Staff's proposed Generation Demand Charge.

Q. How does Staff set the level of its proposed Generation Demand Charge?

A. Staff considers several methods, but ultimately bases its recommended rate on a method it describes as "[t]he cost of owning and operating the actual generation fleets of each utility, excluding the cost of fuel-related operating expenses, divided by the capacity requirements of existing ratepayers."[45] In essence, Staff attempts to calculate an annual revenue requirement for what most Class Cost of Service studies would call the Production Demand-related costs – i.e., the fixed (or as Staff would call them, "stable") costs of owning and operating the Company's generation fleet. These costs generally include the depreciation and return on investment in those plants and the operations and maintenance expenses associated with running the plants,[46] other than the cost of fuel consumed by them. Staff then divides that total revenue requirement by the Company's retail customer demand to create a demand charge to cover this category of costs.

On its face, this would seemingly be a reasonable method for determining this particular charge. However, it isn't reasonable because there are at least two significant flaws in the calculation. First, in Staff's determination of the rate base of the production function (i.e., the Company's investment in production facilities and related inventories), Staff fails to include a rate base offset for Accumulated Deferred Income Taxes ("ADIT") related to the Company's production facilities, despite acknowledging that such offsets for ADIT "would also be typically allocated to these functions in a class cost of service

[45] ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 50, ll. 27-29, filed September 5, 2025.
[46] Ameren Missouri considers some non-fuel O&M expenses to be energy-related in its CCOS, but for simplification of this discussion I am not differentiating those from the majority of costs reflected in Staff's generation demand charge which the Company considers to be Production Demand-related costs.

study."[47] Second, Staff improperly excludes capacity revenues associated with the sale of excess generation capacity from the Company's fleet as an offset to the revenue requirement.

Q. What is Staff's purported rationale for not including a rate base offset for ADIT related to the Company's production facilities in the calculation of its proposed Generation Demand Charge?

A. Staff claims that incorporating a rate base offset for ADIT related to the Company's production facilities in the calculation of its proposed Generation Demand Charge would be "inconsistent with this legislation [S.B. 4], inconsistent with general rate making policy, and would be patently unfair."[48]

Q. Are Staff's claims accurate?

A. No, and it's actually quite the opposite. Staff's decision *not* to include a rate base offset for ADIT is in fact inconsistent with SB 4, inconsistent with general rate making policy, and unfair. Regarding SB 4, there is not even a mention of ADIT in the amendments that added subsection 7 to 393.130 being cited by Staff as support for its position. However, SB 4 also included amendments to Section 393.1400 (the Plant in Service Accounting or "PISA" statute), which does explicitly mention the need to offset the change in plant-related rate base with "changes in all plant-related accumulated deferred income taxes."[49] Thus, under the PISA statute, PISA deferrals for all plant which will serve both large load and non-load customers, must reflect the ADIT offset and thus will benefit both large load and

[47] ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 49, ll. 26-27, filed September 5, 2025.
[48] ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 49, footnote 86, filed September 5, 2025.
[49] 393.1400.3(2) RSMo.

non-large customers alike. Ms. Lange's novel attempt to only benefit non-large load customers is completely at odds with this treatment.

The IRS Normalization Rules,[50] passed by Congress in 1981, prescribe the general rate making policy in relation to plant-related ADIT balances. The IRS Normalization Rules require that the tax benefits from accelerated depreciation are to be shared with customers over the life of the related plant investment. In establishing the IRS Normalization Rules, Congress explicitly considered whether to allow the tax benefits from accelerated depreciation to flow through to the utility's *existing customers at the time the ADIT was generated*, consistent with Staff's proposal in this case, and *rejected that approach,* instead passing a law requiring that these tax savings be "normalized" and shared with the utility's customers *over the life of the related property*, which for the Company's energy centers range from 30-100 years. By mandating that these tax benefits be shared with customers over a period of up to 100 years, Congress was obviously aware that these tax benefits would not ultimately accrue to the same group of customers that existed ("legacy customers" as Ms. Lange labels them) at the time the ADIT was originally generated. Therefore, and in contrast to Staff's assertion, general rate making policy commonly results in an offset to rates of new customers from ADIT balances that were initially established decades prior.

[50] The IRS Normalization Rules under § 168(i)(9)(A)(i) require the taxpayer to compute the federal income tax expense taken into account in setting its rates using a depreciation period that is no shorter than, the period used to compute the depreciation expense for purposes of computing rates. The IRS Normalization Rules ensure that investor-owned regulated utilities are allowed to retain these tax benefits from accelerated depreciation, as opposed to having to immediately flow-through these tax incentives to ratepayers in the form of lower income tax expense in regulated cost of service rates. A violation of these requirements with respect to accelerated depreciation may result in the loss of the right to claim the tax deduction on assets in service as of the date of the violation, as well as for future additions.

Finally, Staff's decision not to include a rate base offset for ADIT related to the Company's production facilities is also unfair. Staff is proposing that LLCS customers should be responsible for paying for their share of the depreciation and return on the Company's production facilities but should not receive any of the tax benefits generated by the returns on those very same investments.

Q. What effect does failing to include a rate base offset for ADIT related to the Company's production facilities have on Staff's calculation of its proposed Generation Demand Charge?

A. Failing to include a rate base offset for Staff's $1.4 billion estimate of ADIT related to the Company's production facilities overstates Staff's proposed Generation Demand Charge by approximately 9%.[51,52] ADIT provides a very real benefit to customers by displacing the need for some amount of utility capital and the cost that goes with it, and Missouri ratemaking reflects this benefit in utility revenue requirements and resulting lower rates paid by customers. As such, consideration of ADIT is absolutely a necessary element for determining "the full cost of owning and operating its generation fleets."[53]

Q. What is Staff's stated rationale for excluding capacity revenues associated with the sale of excess generation capacity from the Company's generation

[51] I calculated these estimates by subtracting Ms. Lange's $1,395,110,916 estimate of ADIT related to the Company's production facilities (per cell C6 on the "cap $ CONF" tab of Ms. Lange's workpaper titled "Confidential – General Workbook") from her Generation Demand Ratebase value (in cell "B6" on the "Calculations" tab of Ms. Lange's workpaper titled "Ameren LLCS other rates"). The result of this modification is a demand charge of $15.16 instead of the $16.60 originally calculated by Ms. Lange, representing an overstatement of 9%.

[52] This is not the first occasion where Staff witness Sarah Lange has failed to account for ADIT in the analysis she has conducted for utility cases – see the Surrebuttal Testimony of Mitch Lansford in File No. EA-2023-0286, which is attached to my testimony as Schedule SMW-S3 for more details of other similar circumstances.

[53] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 15, ll. 10-11, filed September 5, 2025.

fleet as an offset to the revenue requirement used to calculate its proposed Generation Demand Charge?

A. Staff claims that this is appropriate treatment of capacity revenues, saying, "Since the net effect of adding significant load is increasing the net expense or reducing the net revenue, it is not reasonable to allocate the revenue to the customer causing the revenue reduction."[54] This logic is faulty. If it is true that there is excess capacity to sell today that produces the revenue that Staff is excluding from its calculation of its Generation Demand Charge, that means that there is more capacity than is needed to serve the current load (i.e., capacity that was sold wholesale to other load serving entities). However, Staff, in developing its rate, divides the cost of this capacity (more than needed to serve the retail load) by only using the current level of retail load as the denominator of the rate calculation. This means there is a clear mismatch between the costs included in the numerator, which implicitly (due to the existence of capacity sale revenues) can support a higher level of load than the current retail load, and the denominator of the rate that *only* includes the current retail load. This is not a reasonable basis for establishing a retail charge. The numerator and denominator of the rate must be internally consistent. Staff could have, but didn't, do one of two things to remedy this inconsistency: 1) it could include the capacity revenues (that it chose to exclude) as an offset to the revenue requirement to reflect the revenue generating capability of the excess capacity (where in the future that revenue could come from either the market as capacity sales or from new customers such as large load customers that would make efficient use of the existing excess capacity), or 2) it could impute additional load into the denominator to represent the amount of large load (or other)

[54] ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 51, ll. 11-13, filed September 5, 2025.

customer load that could be served by the existing generation fleet. Either of these solutions would reduce Staff's Generation Demand Charge by making the rate calculation internally consistent.

Table 3 below illustrates this effect with a hypothetical, but plausible example. Assume a utility had 2,000 MW of generating capacity with a revenue requirement of $100 million, but only 1,800 MW of load – i.e., they had 200 MW of "excess" capacity length.[55] Assume they sold that length in a given year for $4 million (a little over $50 per MW-day), resulting in a net revenue requirement for this production capacity of $96 million. Staff would calculate the rate as shown in line 6, which divides the gross revenue requirement in line 3 by the mismatching load in line 2 that is 200 MW lower than the amount of capacity available. However, in reality at that given time, the capacity sales revenues are real – meaning the appropriate rate should be as shown in line 7, which divides the full net revenue requirement in line 5 by the total customer load in line 2, which is how a rate would be set today in order to allow the utility an opportunity to recover its revenue requirement from its existing retail load. Now imagine in the future that 200 MW of new load (let's call it a single large load customer of 200 MW) initiates service. Consistent with Staff's theory, it *could* be appropriate to exclude the capacity sales when setting a rate for this future state. However, that is true *if and only if*, in that future state, the total gross revenue requirement is divided by the new level of retail load that will exist in that future state – i.e., 2,000 MW inclusive of the new 200 MW large load customer. This approach, which imputes the load that is expected in the future state, but excludes the capacity sales

[55] To simplify the example, I am ignoring losses and reserves in my hypothetical. However, the effect is the same when including those elements, there just would need to be more complexity shown that is unnecessary for the illustrative effect here.

revenue (as it must, since the capacity will be used to serve the new 200 MW customer), represents a rate that would recover the utility's actual revenue requirement from its then current retail customer base. That rate is shown in line 8. Note that in both line 7 and 8 – i.e., the two methods that do not include mismatching numerators and denominators – the rate is *lower* than in line 6 which includes Staff's mismatch. In my opinion, the rate reflected in line 8 is the most reasonable approach, as the calculation reflects the condition that we expect when large load customers would be taking service – i.e., that capacity would be used to meet a higher future retail load obligation and thereby implicitly generate revenues at the retail rate rather than simply sold on the wholesale market.

Table 3 – Illustration of Staff's Mismatching Rate Calculation Methodology and the Two Possible Solutions to Fixing It

Line	Description	Amount
1	Total Capacity (kW)	2,000,000
2	Total Load (kW)	1,800,000
3	Gross Revenue Requirement Associated with Generation Capacity (Excluding Capacity Sales Revenue)	$100,000,000
4	Capacity Sales Revenues	$4,000,000
5	Net Revenue Requirement (Including Capacity Sales Revenues)	$96,000,000
6	Per kW Rate Using Staff's Method (Line 3 divided by Line 2 divided by 12 months)	**$4.63**
7	An Approach: Per kW Rate Recognizing Capacity Sales Revenue, which represents revenue generating capability of excess capacity (line 5 divided by line 2 divided by 12 months)	**$4.44**
8	Most Reasonable Approach: Per kW Rate Based on Exclusion of Capacity Sales Revenue but Imputing Retail Load that Can and Will Contribute to Covering Revenue Requirement in the Future (Line 3 divided by Line 1 divided by 12)	**$4.17**

Both of these issues – the deliberate exclusion of ADIT and capacity revenues – are just two examples of how Staff's proposal is outside of normal ratemaking, leading to the result of Staff's rate being too high to accurately reflect the Company's production demand-related unit costs of serving large load customers. The result: large load customers would unfairly overpay.

Q. How does Staff calculate its proposed energy charge rates?

A. Staff provides large load customers with two options: 1) take energy priced at the market-based locational marginal price ("LMP") at the load CP Node at which the customer is served, or pay an exorbitant fixed energy rate, that even Staff's own witness described as a rate that a customer would be "irrational" to select at hearing when discussing the similar charge Staff proposed in Evergy's large load tariff case.[56] In doing so, Staff has created a lose-lose situation for prospective large load customers. Choice 1: make billions of dollars of investments in extremely energy intensive facilities that will then be exposed to the volatility and unpredictability of market energy prices for over a decade. Choice 2: dramatically overpay for energy. Under either of these options, Staff badly misses the mark by using a *wholesale* market price as the basis for a *retail* service charge that should reflect Company's actual energy-related costs of providing *retail* service – i.e., the costs that are or will be actually reflected in the Company's revenue requirement.

Q. Is asking customers that are about to invest billions of dollars in fixed assets to take long-term energy supply at spot market prices a reasonable way to provide service to, let alone try to attract, customers?

[56] File No. EO-2025-0154, Tr. (Vol. 3) p. 100, l. 22 to p. 101, l. 3.

A. No. Even in deregulated markets where such customers have to "shop" for energy rather than receive generation services as a part of bundled utility offerings, my understanding is that such customers lock in long-term purchased power agreements that give them visibility and/or certainty on the energy supply prices. It's even more outrageous to expose such customers to spot market energy prices when they are paying an extremely significant generation demand charge (as proposed by Staff) to pay for fixed generation assets. It makes no sense to charge customers for the fixed costs of generation assets but not give them the benefit of receiving energy at prices based upon those assets' actual production costs but instead make them buy energy at full market prices.

Q. In her surrebuttal testimony in Evergy's large load tariff case, Staff witness Lange hypothesized that "[i]f customers are given the option to enter into an agreement with EMM or EMW to accept direct billing of wholesale energy expense for that LLPS customer's load node, including day ahead, real time, and ancillary charges, many would choose that option." Do you agree that many large customers are likely to exhibit a preference for spot market based energy costs?

A. No, and experience in a neighboring jurisdiction suggests otherwise. In the state of Illinois, which has a deregulated energy market (utilities are not vertically integrated and customers procure energy from independent power marketing company's or through state run market-based procurement processes), the utilities offer an energy-supply option (Hourly Supply Service, or "HSS") that is basically the same as Staff's proposal in this case (and Evergy's) – a pricing option under which customers pay energy charges based on the hourly LMP at which their load is settled in MISO. Based on an Illinois Commerce

Commission report,[57] in 2023 only 6.6% of large industrial customers representing just 5.0% of the total large industrial customer load participated in this hourly pricing option. Contrary to Staff's expectation that "many would choose that option," where the option exists, very few choose it.

Q. Does the wholesale market price represent the variable costs of providing energy to retail customers within the Company's revenue requirement?

A. No, as discussed further below.

Q. Does Staff think they do?

A. Not according to the Staff's auditing function. When the Staff's auditing function employees build a revenue requirement in a Missouri electric utility's rate case, there is not a line item in Staff's revenue requirement model that reflects the utility's retail load times the LMP as a representation of the utility's variable energy-related costs. If Staff was right in this case – that the wholesale market price represents the variable cost of providing energy to retail customers – such a line item would necessarily have to be included in the revenue requirement, which would possibly support using the LMP itself as a basis for retail charges designed to produce revenues to cover that revenue requirement.

Not only does Staff's audit function recognize that the market price of energy does not represent the variable cost of the utility's production of energy to serve customers, so too does Ms. Lange's boss at the time, Mr. Busch, who testified during the Evergy hearings (where Staff is making a similar proposal) as follows:

> Q. Would you agree that the cost for Evergy to generate a megawatt hour of electricity is not equal to the market price of energy in a given hour

[57] Illinois Commerce Commission, "Comparison of Electric Sales Statistics for Calendar Years 2022 and 2023." July 2024.

except by wild coincidence? A. I think that's correct. I think I can agree with that.[58]

Q. Is there anything in Staff's revenue requirement model in a rate review that does represent the utility's embedded variable energy-related production costs within that revenue requirement?

A. Yes. Staff and electric utilities in Missouri calculate, directly from their revenue requirements, Net Base Energy Costs to use as the baseline for their FAC tariffs. This calculation is a representation of the utility's actual variable production costs including fuel and purchased power net of off-system sales, which is also stated as a rate in the FAC tariff called the Base Factor. The Company's Base Factor of approximately 1.4 cents per kilowatt-hour is lower than Staff's analysis suggests that an LMP-based energy charge would be (and likely would be),[59] in a manner that is internally consistent with the revenue requirement used to establish base rates for the utility.

Q. It sounds like Staff's energy charge proposal would be likely to create a rate in this case is too high to reflect Ameren Missouri's actual cost of service. Why does use of the LMP as Staff's energy charge create this result?

A. The only reasonable conclusion is that setting a discrete charge to cover the variable energy-related costs using the LMP will over-recover the energy-related production costs included in the revenue requirement. Staff witness Lange has misinterpreted the "buy all, sell all" nature of wholesale energy markets in her development of this charge, just as she did in her Class Cost of Service work in Ameren Missouri's most

[58] File No. EO-2025-0154, Tr. (Vol. 2) p. 247, ll. 20-25.
[59] The Company's current base factor is approximately 1.4 cents per kWh and the Staff's workpaper calculation of the historical average LMP that may be considered a proxy for Staff's expectation of its energy rate is approximately 3.1 cents per kWh.

recent electric rate review.[60] While the mechanics of wholesale market design in MISO does indeed result in the mechanics of the utility selling all generation into the market and buying all energy from the market that is needed to serve load, this necessarily results in *equal and offsetting transactions*[61] that Federal Energy Regulatory Commission ("FERC") *requires* utilities to net for purposes of financial reporting. That netting has also been recognized explicitly by this Commission in its discussion of "true purchased power" in File No. ER-2014-0258 that established the treatment of transmission expenses within Missouri electric utilities' FACs.[62] And FERC's netting requirement (and this Commission's recognition of it in the FAC context) exists for good reason – the utility still plans and operates its generation on an integrated basis for the primary purpose of serving its own load, while protecting its customers from the very exposure to wholesale power prices that Staff's proposal is based upon.

There is simply no expense on a utility's income statement associated with the purchase of power for load from the market unless the utility did not have sufficient generation of its own to cover its load, and it was therefore truly buying energy from the market at large instead of self-supplying it. That this expense does not exist on the utility's income statement is appropriate and is also illustrative of the reason it also does not exist

[60] File No. ER-2024-0319. See the Surrebuttal Testimony of Ameren Missouri witnesses Nicholas Phillips and myself, excerpts of which are attached to this testimony as Schedule SMW-S4.
[61] While the LMP for the sale and purchase of energy are unlikely to be identical, the energy component of the LMP for both transactions is identical and therefore offsetting. Differences in LMP arise from the inclusion of the cost of transmission congestion and losses in the same transaction.
[62] To the extent that the Commission deviates from the FERC netting approach for purposes of ratemaking for Missouri electric utilities, as Staff has now suggested on multiple occasions, it would also be entirely appropriate and consistent with that decision to include 100% of transmission expense within the FACs of those utilities since any such deviation would necessarily mean that there is no such thing as "true purchased power".

in a utility's ratemaking retail revenue requirement. *Setting a charge at this level is not reflective of the utility's cost of providing service, period.*

Q. Does utilization of a market energy charge in a retail rate that already includes charges that cover the fixed costs of the generation fleet systematically bias the total rate to either over- or under-recover the revenue requirement?

A. Yes, in practice it would tend to systematically over-recover the revenue requirement. That is because the LMP itself provides almost all generators with sufficient revenue to contribute *at least some amount* toward the recovery of that generator's fixed costs.

Q. Aren't those the same fixed costs that are already being covered by Staff's Generation Demand Charge?

A. Yes, the very same. Recall that in MISO wholesale energy markets the energy component of the LMP is equal to the offer price, typically based on the variable production cost of the *most expensive* unit operating in the market at a given point in time. That means that for *other units*[63] – those that are not the marginal, price-setting unit – the energy component of the LMP is *higher* than the variable cost of producing energy. When utilities in Missouri generate energy above and beyond their load requirements, these excess off-system sales produce margins (revenues in excess of the variable cost of generation) that reduce the revenue requirement for the benefit of all customers. That the LMP is sufficient to make *any* contribution to the fixed cost of a generator, and that Staff is using the LMP to set a retail energy rate when they already designed another rate to

[63] Some exceptions exist, for example, when a higher cost unit is brought on for reliability purposes. But in that circumstance market designs also generally provide "make whole payments" that cover those higher costs to the generator, ensuring that they at least fully recover their variable costs of generation, like the marginal unit in the market does.

recover *all* of the fixed costs of generation,[64] necessarily means that Staff's rate *double counts* some amount of generation costs – i.e., it charges more than the cost of service, and by implication would result in a utility systematically recovering more than its revenue requirement associated with the provision of service to a customer. The result: once again, large load customers would unfairly overpay.

Q. Does Staff's proposal reflect a misunderstanding of the foundational business model that underlies the structure of vertically integrated, rate regulated, utilities?

A. Yes. There is a term for a company that generates power and recovers its costs based on market prices – it is called a *merchant generation* company, and it isn't rate regulated by a state commission. Ameren Missouri is not a merchant generation company. As described in my surrebuttal testimony that I attached from the ER-2024-0319 case, Staff's misinterpretation of "buy all/sell all" implicitly turns the utility into a merchant generator that markets its generation at wholesale, returns the proceeds of those market sales to its customers, and then serves load directly from the market. That is completely antithetical to the nature of a vertically integrated utility. There would be no need for, or value from, an IRP if the utility was just a power marketing company that built generation for market sales. And if a utility's rates were purely market based and therefore its cost recovery for power plants that it built was tied to market prices rather than its actual cost of owning and operating the plants, the utility would likely not even build the plants at all but rather would just serve its load from the market (*which would also leave reliability to market forces or RTO mechanisms*, which is not the result I believe the Commission is

[64] And then some, due to the flaws in the generation charge development that I discussed previously.

looking for). Staff's proposal to charge rate regulated retail customers for power generated by a vertically integrated utility a rate that is exclusively tied to market prices is completely at odds with the Company's status as a vertically integrated, rate regulated utility and is wholly inappropriate.

Q. Is the Staff's alternate proposal of a fixed energy rate a reasonable alternative for prospective customers?

A. No. As I mentioned previously, during the Evergy large load tariff hearing, which included a similar proposal, Ms. Lange herself admitted that a customer would be "irrational" to select this rate. That is because the energy rate that Staff proposed for this fixed price option, but for which they provided absolutely no rationale for or justification of, whether intentionally or not, is equal to the *summer on-peak* wholesale market energy price Staff calculated in one of its workpapers.[65] So not only is this price apparently and inappropriately market based as discussed above, but it applies the market price from the 552 hours that comprise most expensive part of the year[66] to the energy the customer would consume in all 8,760 hours of the year. I agree with the Staff witness's assessment that a customer would be irrational to sign up for this rate.

Q. Have you calculated what the effective "all-in" cost per kilowatt hour would be for a large load customer with an 85% load factor under Staff's proposal if selecting the fixed energy price option?

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[65] The 5.1 cents per kWh in Staff's proposed tariff equals, after rounding, the rate in cell E17 of Staff witness Sarah Lange's workpaper titled "Ameren LLCS energy rate.xlsx". That labels on cell E 17 indicate it represents the calculation for "Summer" and "On Peak".

[66] Review of Staff witness Sarah Lange's workpaper titled, "Ameren LLCS energy rate.xlsx" indicates the definition of summer on-peak hours included 6 hours per day through the summer season of June – August, a total of 92 days, resulting in a total of 6 x 92 = 552 hours.

A. Yes. Staff's fixed rate option would result in an initial cost per kilowatt hour for large load customers of 10.6 cents per kilowatt hour.[67] That compares to a cost that other industrial customers of a similar load factor served at transmission voltage would pay on the Company's LPS tariff of approximately 6.0 cents per kilowatt hour. Staff's rate would be a *76% premium* to the Company's existing large industrial rates!

Q. What would the all-in average cost per kWh be if the customer selected the market-based price option?

A. The biggest problem is that the customer will never know its all in rate until after the fact, when the market prices have occurred. However, using Staff's workpaper calculation of the historical average LMP as an indicator of the potential level of the energy market charges, one still gets an average rate for large load customers of 8.8 cents per kilowatt hour, a rate that is fully 47% higher than other industrial customers – while also being subject to market risk and volatility for the 15 to 17-year term of the large load customers' ESAs!

Q. Let's move on to the Staff's proposal for the transmission demand charge. Do you have any concerns with it?

A. Not with the development of the rate per se, but I do have an issue with the fact that Staff would propose to charge this rate to customers *in addition to* having those same customers also pay 100% of the upgrades to the network transmission system that are needed to enable their service.[68] Network upgrades are related to shared assets that benefit *all* customers, the costs of which are reflected in base rates that cover the revenue

[67] Presumably, it would actually be higher than this because Staff has additional charges that it has labelled "TBD" but not accounted for in its numbers.
[68] ET-2025-0184, *Staff Recommendation/Report*, p. 28, ll. 16-17, filed September 5, 2025.

requirements that arise from those same shared assets. While in certain circumstances the upgrades might not have been needed but for the service provided to a particular customer, the upgraded assets are system enhancements that are available and useful to all customers.

I think a useful analog to think about here for how the embedded cost rate inter-relates with incremental investment driven by a particular customer is the revenue test that is included in the Company's Distribution System Extensions tariff for connecting new load to the system. When a new customer needs distribution investment in order to connect them to the system, we look at the revenue requirement impact of the investment and compare it to the expected revenue to be received from the customer based on application of the current retail rates. If the customer is expected to provide revenues that equal or exceed the incremental revenue requirement of the system extension, then no upfront contribution from the customer is required. I think the same principle is useful to think about with respect to network transmission upgrades needed to enable large load service.

Q. Would application of Staff's transmission demand charge produce revenues sufficient to cover the incremental revenue requirement impact of any expected transmission system network upgrades?

A. Of course, the final answer depends on what customers ultimately take service, how much revenue they generate, and what upgrades need to be made. But my expectation is that the transmission charge is *more* than sufficient to cover any incremental impacts of network transmission investment on the revenue requirement. And it is certainly sufficient for the Commission to determine that the large load customers can be reasonably expected to pay their representative share of costs.

Q. Can you provide some numerical evidence to support that expectation?

A. Yes. Application of Staff's proposed transmission demand charge of $4.79 per kilowatt-month would result in approximately $115 million of revenue per year[69] if the Company were to serve 2 gigawatts ("GW") of large load, which is consistent with the load values reflected in the risk analysis presented in my Direct Testimony. The variable transmission costs that would be incurred to serve that load would primarily relate to charges under MISO Schedule 26A. Based on the MISO 26A charge level reflected in the revenue requirement in the Company's most recent electric rate review[70] (File No. ER-2024-0319), Schedule 26A charges represented approximately $1.76 per MWh. Assuming the 2 GW of large load operated at an 85% load factor,[71] those large load customers would consume approximately 14.9 million MWh annually, resulting in Schedule 26A charges of approximately $26 million annually. $115 million of transmission related revenue less $26 million of incremental MISO transmission charges would leave approximately $89 million to cover the annual revenue requirement of incremental investment in network transmission upgrades. Given an assumed depreciable life of 40 years and a pre-tax cost of capital of approximately 8.5%, $89 million of annual revenue would be sufficient to cover the first-year fixed revenue requirement of *over $800 million* of incremental transmission investment in network upgrades.

As I mentioned previously, actual network transmission upgrade costs will depend on what customers of what size are served at what locations. However, for a very realistic

[69] $4.79/kw-month x 2000,000 kW x 12 months/year = $114.9 million/year.
[70] Source – workpaper of Company witness Tom Hickman titled "MO ECOSS_2024 Final". LPS class 26A charges allocated of $6.3 million from cell T27 of tab called "EXP1", divided by 3.6 million MWh from cell C21 on tab "Cust".
[71] The same load factor used by Staff in its hypothetical customer calculations.

sense of what those costs might be expected to be in a real scenario, I looked at the network transmission upgrade cost estimates the Company reported in response to Staff Data Request MPSC 5 in this case. In that DR, based on the study of approximately 2.3 GW of large load projects, network upgrade costs were estimated to be $123 million – well below the $800 million of investment that could be supported by the revenues generated by Staff's transmission demand charge. While actual costs will vary based on the factors I identified above, this example suggests that there is significant headroom in existing transmission rates to support network transmission upgrades without resorting to upfront charges to large load customers to cover those investments. I would note that the embedded cost of transmission reflected in the Company's LPS rate (i.e., the Company's large load rate proposal) would produce a similar amount of transmission-related revenues (implicitly) to the level I have estimated to result from Staff's transmission demand charge (i.e., that roughly $115 million), and the risk analysis I conducted for my Direct Testimony appropriately segregated those transmission revenues in a manner where they were not assumed to be available to cover the incremental revenue requirement in that analysis. Said another way, I fully accounted for the need to dedicate the transmission-related revenues in base rates to covering transmission-related costs. The upshot of this transmission charge discussion is that, under any rate proposal in this case, it should be unnecessary, for purposes of SB 4 considerations or just general ratemaking policy reasons, to charge large load customers upfront for any network transmission upgrades.

Q. Next, please discuss Staff's proposed "Stable Fixed Revenue Contribution Charge" and "Variable Fixed Revenue Contribution Charge."

A. I think it's a fair question which of Staff's proposed charges within its large load rate structure is the most removed from having a legitimate basis in cost of service analysis, but at the end of the day it is these charges that truly take the "overcharge large load customers" cake. Staff simply takes all of the other charges it has concocted and grosses them up by 24.77%.

Q. What is Staff's stated rationale for these gross up charges?

A. Staff suggests that these charges will contribute to the Company's "day-to-day costs of doing business, such as computer systems, computer software, office buildings, office furniture, management employees, investor relations costs and expenses, other overheads, and the revenue requirement associated with policy-driven activities, such as solar rebates, electric vehicle charging stations, and supports for low-income rate payers."[72] I'll refer to this categorization as Administrative and General ("A&G") expenses, as that is the cost of service categorization into which many of these costs tend to fall. And Staff set the level of the charge based on a goal of achieving a gross up of 20% of the revenue from the rest of the charges, which Staff says is "essentially the floor for economic development discount recipients established by Section 393.1640 RSMo."[73] To be clear, this means that these day to day costs for which Staff is designing the charge to cover are not based on an assessment of those day to day A&G costs *at all*, but rather on a percentage of all of the utility's *other* costs, with that percentage coming from the economic development law Staff referenced.

Q. Is Section 393.1640 RSMo (the economic development law) an appropriate basis for establishing a cost-based rate for large load customers?

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[72] ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 58, ll. 30-34, filed September 5, 2025.
[73] ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 59, ll. 2-3, filed September 5, 2025.

A. No. That section of the law exists to determine when and to what degree new and expanding customers can and should, for policy reasons in support of economic development, be allowed to receive *discounted* rates from the level that the Commission has otherwise determined to be the just and reasonable cost-based rates for their class. Said another way, this section of law is all about developing a rate (or discount applied to a rate) that *intentionally deviates* from cost-based rates – again, for policy reasons. It has nothing whatsoever to do with how to *establish* a *cost-based* rate. The fact that the legislature saw fit to give certain customers discounted rates so long as they made a certain contribution to fixed cost recovery in no way means or even suggests that that level of contribution is reflective of the utility's A&G, or any other costs, of serving large load customers. Essentially, Staff's use of this percentage to create a rate applied to large load customer bills is nothing short of the establishment of an arbitrary charge that Staff seems to hope is at least loosely reflective of some costs of providing utility service.

Q. Is using an arbitrary adder, even if that adder is based on a number that appears in Missouri law associated with an unrelated topic (i.e., the conditions under which economic development discounts *from* cost-based tariffed rates may be offered), a reasonable basis for establishing the cost basis for a large load retail rate?

A. No, I can't even imagine why Staff would think it is.

Q. Do you have any other criticisms of the "Stable and Fixed Variable Revenue Contribution Charges?"

A. Yes. Above and beyond the arbitrary nature of the 20% statutory contribution that Staff points to as the basis of the charge, Staff then goes on to further gross up its gross-up rate by another amount, purportedly to cover income tax impacts of the charge.

Q. Should revenues that cover expenses in the revenue requirement be grossed-up for taxes as part of the ratemaking process?

A. No. When rates are designed to produce revenues that match, so as to create a one-for-one offset to, an expense (of course here, Staff's revenues only do that in the loosest of senses, but I think it is still a fair characterization of Staff's intent), there is *no resulting income tax impact*.

Q. Why?

A. When a utility receives rate revenues to cover a utility expense, it receives the revenue to cover an expense in exactly the same amount (e.g., if the expense to be covered is $100, the utility receives $100 in revenue). The net of the two is zero income. On what are taxes paid? Income, but since there is no income there is no income tax expense. The effect of Staff's gross-up of their gross-up factor for income taxes is just to pad Staff's rate for "phantom" tax expenses that do not exist in the context of the rate Staff is designing.[74] The result: a third time when large load customers would unfairly overpay.

Q. You indicate that each of these methodological flaws all are biased such that Staff's rate would overcharge large load customers. How does that square with the average per kilowatt-hour cost for large load customers under its tariff versus the Company's proposed tariff?

[74] Again, I would encourage a review of the Surrebuttal Testimony of Mitch Lansford in File No. EA-2023-0286, which, again, I have attached to this testimony as Schedule SMW-S2, for another example of Staff witness Sarah Lange introducing "phantom" income taxes that do not exist in reality into a revenue requirement calculation as a part of her analysis. This is similar to her omission of ADIT I discussed earlier, which also occurred in her analyses in each of these cases. I have personal knowledge of the "threshold analysis" errors as documented in Mr. Lansford's testimony and schedules thereto in that case.

A. As I stated previously, Staff's rate results in an average cost per kilowatt-hour that is either 76% or 47% higher than the Company's 11(M) rate which the Company proposes to serve large load customers under, depending on whether the customer chose the fixed energy rate or market based energy rate – consistent with my expectation based on all of the methodological flaws I have identified that suggest that Staff's rate is designed in a manner that should be expected to overcharge customer.

Q. Please summarize your perspective on the cost basis of Staff's proposed large load rate.

A. It is internally inconsistent at best and totally lacking at worst and it would grossly overcharge large load customers, who would pay more than a representative (fair) share. To be clear, as I stated at the outset of my testimony, I am not even delving into *every* problem with Staff's proposal. I have only commented on *some of the most egregious* problems with it. That said, the fact that Staff's Generation Demand Charge is systematically biased high by not reflecting ADIT or capacity revenues, that Staff's energy charge is systematically biased high by reflecting wholesale market prices that contribute to the same fixed costs (i.e., that double counts costs) as the Generation Demand Charge, and that the Stable and Variable Fixed Revenue Contribution charges are arbitrary, with no relationship to Ameren Missouri's actual costs, and then further biased high by grossing them up for phantom income taxes, suggests that Staff's rate is wholly unreasonable. If all of the Company's retail rates were made this way, it would be in a position where it was likely to over-recover its Commission-determined revenue requirement and customers subject to the rate would simply pay too much. Large load customers would also pay too much here, meaning Staff's rate would obviously decrease the competitiveness and attractiveness of Missouri as a home for the investments in economic development that such customers can create.

VII. STAFF'S REGULATORY LAG PROPOSALS ARE INAPPROPRIATE

Q. Please describe Staff's recommendation related to the accounting treatment for LLCS customer revenues?

A. Staff is recommending that, "[t]o address regulatory lag, creation of a deferred regulatory liability account into which Ameren Missouri defers the level of LLCS revenues described in Staff's recommended tariff…The revenues to be deferred, would include the Generation Demand Charge revenue, and the Variable Fixed Revenue Contribution and Stable Fixed Revenue Contribution charge revenues. This account would offset production ratebase and be amortized over a 50-year period."[75] Staff notes that "[t]he revenue recorded to the regulatory liability account will not be treated as revenue in setting rates."[76]

Staff also recommends that "[t]he Commission should order the creation of a deferred regulatory liability account into which Ameren Missouri defers the level of LLCS revenues each month that are equal to the values incurred for the LLCS customer that are subject to FAC treatment. These deferred amounts should be flowed back to customers through the FAC after a future rate case, using an amortization period of 4 years or less."[77]

Q. What is Staff's rationale for its proposal to treat LLCS customer revenues differently from all other base rate revenues?

[75] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 21 ll. 12-17, filed September 5, 2025.
[76] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, Appendix 2, Staff Schedule 1, p. 4 ll. 8-10, filed September 5, 2025.
[77] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 21 ll. 19-24, filed September 5, 2025.

A. Staff states that it believes the positive regulatory lag[78] that will occur between any increase in LLCS customer revenue, and when that revenue is recognized in a rate case is somehow different than what it calls "ordinary" positive lag associated with customer growth. Staff's concerns are focused on the scale of the LLCS customer revenues and a *claimed* lack of offsetting revenue requirement increases.

Q. Please provide some overview about the role of regulatory lag in the ratemaking process in an historical test year jurisdiction like Missouri.

A. Ratemaking in Missouri is based on a review of the utility's cost of providing service over a historical period as compared to its revenues over the same period, subject to certain normalizations, annualizations and other regulatory adjustments. The use of a historical test year results in regulatory lag – i.e., inflation, new investment placed into service, and other variations in costs mean that the utility's rates frequently do not fully cover its current period costs when rates take effect. Put another way, while the historical test year-based revenue requirement is intended to be a proxy for what the actual revenue requirement will be once rates are set, it often is insufficient by a significant amount.

Q. Can regulatory lag result in a utility's rates being higher than its current period costs?

A. It's certainly possible, but it is also certainly far from the norm. We are in an industry (perhaps like most other businesses) with inclining costs over time. That is particularly true today where utilities are in an investment cycle to replace aging infrastructure and retiring generation facilities. Certain categories of cost may decline.

[78] Staff defines "positive regulatory lag" as regulatory lag that is beneficial to the utility, such as an increase in revenues or a decrease in the cost of service, and "negative regulatory lag" as regulatory lag that is detrimental to the utility, such as a decrease in revenues or an increase in the cost of service.

Revenues may increase through load growth, which also has the effect of creating lag that offsets inclining costs and could theoretically result in a utility's revenue exceeding its revenue requirement. However, it is typically the case that regulatory lag negatively impacts Missouri utilities' ability to earn the rate of return authorized by the Commission due to the prevalence of increasing cost categories.

Q. What is the rationale for perpetuating a system that includes such an impediment to utilities earning the rate of return that the Commission authorizes as reasonable?

A. Regulatory lag tends to provide an incentive for cost control and efficient management of the business. The fact that increases in costs inherently diminish the utility's earnings until a subsequent rate case many months or years later gives utilities incentive to hold the line on costs to protect its earnings as best they can. While this incentive feature is real and important, it also can create challenges for utilities to make the investments needed in modern infrastructure while maintaining adequate financial results to attract the capital needed to invest in that infrastructure. In order to create an environment where utilities can attract that capital, a constructive regulatory framework that relies on regulatory lag should be as balanced as possible, meaning that a utility should not be expected to absorb earnings declines from *unfavorable* (negative) regulatory lag but, in the event that it does experience potential earnings enhancement from *favorable* (positive) lag, be expected to forego the benefit. Also, the availability of regulatory tools, such as PISA that exists in Missouri law, is critical to ensuring the financial integrity of utilities through periods of substantial investment. Regulatory lag should not be so extreme as to prevent utilities from investing in their systems while still maintaining their financial integrity.

Q. Would adoption of Staff's revenue deferral proposal represent a significant policy shift in the treatment of regulatory lag, and if so, do the facts and circumstances warrant such a shift?

A. Yes, adoption of Staff's proposal would represent a significant policy shift and no, such a shift is not warranted. Even with the availability of PISA, Missouri electric utilities are still disproportionately experiencing unfavorable regulatory lag. As I just mentioned, a balanced policy would not expose utilities to such unfavorable lag for sustained periods of time only to take away all of the benefits of favorable regulatory lag when there are opportunities for utilities to offset some of the financial losses it has incurred due to the systematic earnings erosion that arises from the typical form of inclining cost regulatory lag.

Q. Has Staff previously testified that opportunities for favorable regulatory lag are a critical ingredient in cost of service rate regulation?

A. Yes. The following testimony on regulatory lag was provided by Staff witness Keith Majors in File No. ER-2024-0319:

> **Q. What is regulatory lag?**
>
> A. Regulatory lag refers to the time between when a utility experiences a change in expense or revenue levels and when that change is recognized in rates that the Commission allows a utility to charge its customers. Regulatory lag can either increase or decrease a utility's actual earnings performance compared to its authorized rate of return in between rate cases. It can be beneficial to customers, as well as to utilities. When a utility's costs increase or its revenues decrease over a period of time, regulatory lag will tend to reduce the utility's profits, adverse to the utility, unless other circumstances either completely offset or mitigate the expense increases or revenue declines. When expenses are decreasing or revenues are increasing, regulatory lag will reward the utility with increased profits during the interval before the rates are changed by the Commission to address the decreased costs or increased revenues, which is a benefit

> to the utility. Regulatory lag provides the utility with either a penalty or a reward under traditional cost of service ratemaking where all costs are considered. This inherent penalty or reward system incentivizes a regulated utility to produce lower costs levels in between rate cases and to maximize efficiency.[79]

Another example from File No. ER-2018-0145 and ER-2018-0146, also from Staff witness Majors:

> Utility managers working with regulatory lag, much like managers of competitive businesses working with fixed prices of goods and services, seek to find ways to operate the business more efficiently to counteract expense or rate base increases or potential revenue decreases during the period of time of when prices are fixed, or regulatory lag. Conversely, utilities benefit from regulatory lag when expenses or rate base decrease or when revenues increase while rates remain unchanged. This is exactly why regulatory lag is a critical ingredient in cost of service rate regulation.[80]

Staff's prior testimony leaves no room for ambiguity—regulatory lag is meant to be a two-way street. As noted by Mr. Majors above, regulatory lag "can be beneficial to customers, as well as to utilities." However, Staff's proposal in this case upends the "inherent penalty or reward system" referenced by Mr. Majors as a critical ingredient in cost of service rate regulation by removing any potential "rewards" available to the utility from growing revenues by attracting LLCS customers to its service territory.

Q. Have other parties to this case similarly acknowledged that opportunities for favorable regulatory lag are a critical ingredient in cost of service rate regulation?

A. Yes. For example, OPC provided the following commentary on regulatory lag in File No. EW-2016-0313:

> Regulatory lag is not, in and of itself, inherently bad for the utility. The Commission recognizes that there are shared benefits, as well as risks, that run to both shareholders and ratepayers. Regulatory lag can serve to make the utility more efficient and more prudent, as

[79] File No. ER-2024-0319, Keith Majors Rebuttal Testimony, p. 3, l. 16 to p. 4 l. 7.
[80] File No. ER-2018-0145 and ER-2018-0146, Keith Majors Rebuttal Testimony, p. 5, ll. 9-15.

> well as provide the utility with retained benefits from synergies. Regulatory lag is a phenomenon which naturally occurs in ratemaking because the regulatory ratemaking process lags behind the actual costs and revenues incurred by the utility. See James C. Bonbright et al., "Principles of Public Utility Rates", 96 (2nd ed. 1988). When a utility is under-recovering revenues, regulatory lag can be seen as deleterious to the utility. Noranda Alum., Inc., et al., v. Union Elec. Co. d/b/a Ameren Mo., 2014 Mo. P.S.C. Lexis 882, *29-30 (2014). When a utility is over-recovering revenues, regulatory lag can be seen as deleterious to the customer. Id. Traditional regulatory ratemaking is predicated on the idea that over a sufficient period of time the benefits and detriments of regulatory lag balance for both the utility and the consumer; sometimes a utility will over-recover, sometimes it will under-recover. See Alfred E. Kahn, The "Economics of Regulation: Principles and Institutions", 48 (1989). In effect, regulatory lag creates the "quasi-competitive environment" that mimics how competitive firms operate and ensures that natural monopolies are not abusing their power. (Footnotes omitted.)[81]

As noted above by OPC, "traditional regulatory ratemaking is predicated on the idea that over a sufficient period of time the benefits and detriments of regulatory lag balance for both the utility and the consumer; sometimes a utility will over-recover, sometimes it will under-recover." If Staff's intent is to eliminate any possibility for the utility to benefit from favorable regulatory lag, then ratemaking becomes one sided, and the benefits and detriments of regulatory lag will no longer balance.

Q. Please summarize your overall opinion respecting what the Commission should do with Staff's revenue deferral proposal.

A. The Commission should reject it. Staff's recommendation to defer LLCS customer revenues to a regulatory liability is entirely inconsistent with the ratemaking treatment of similar increases in other customer revenues associated with customer growth and replaces the "inherent penalty or reward system" referenced by Mr. Majors as a critical

[81] File No. EW-2016-0313, *Initial Comments of the Office of the Public Counsel*, p. 4 – 5, filed July 8, 2016.

ingredient in cost of service rate regulation with an asymmetrical penalty system that removes the incentive for a utility to grow its revenues, thereby benefiting all customers by spreading the utility's fixed costs across higher delivery volumes and supporting economic development in the state of Missouri.

Q. As noted above, Staff suggested that the scale of potential LLCS customer revenues are a justification for differentiating the treatment of favorable regulatory lag associated with those revenues from so-called "ordinary" regulatory lag. How do you respond?

A. The potential scale of the LLCS customer revenues alone does not constitute a valid basis for completely upending the inherent penalty or reward system that underlies traditional cost of service ratemaking. Additionally, Staff's attempts to quantify the scale of potential favorable regulatory lag available to the Company are grossly overstated, as further discussed below, and lack critical context regarding the unfavorable regulatory lag Missouri electric utilities are already exposed to.

Q. In developing their recommendation, did Staff provide any testimony or analysis on how the potential favorable regulatory lag related to LLCS customer revenues compares to the Company's historical and future uncovered costs resulting from unfavorable regulatory lag?

A. No. Staff's recommendation is based on a completely one-sided analysis that fails to acknowledge regulatory lag cuts both ways. In making its decision on Staff's proposal, the Commission should also consider the historical and likely future inability of the historic test year-based ratemaking paradigm to cover the Company's costs due to unfavorable regulatory lag and ensure that the benefits and detriments of regulatory lag reflect a reasonable balance for both the utility and the consumer.

Q. Has Staff previously acknowledged that it would be unfair to take away any favorable regulatory lag from increasing revenues without also considering the unfavorable regulatory lag faced by the utility from increasing costs?

A. Yes. In Evergy's large load tariff case,[82] Staff witness James Busch, Director of the Industry Analysis Division, testified:

> Q. So if there's -- if there's X dollars of new revenues coming from large load customers but their [sic] offsetting cost increases going on in utility's business, your tracker's only going to take into account the revenues for large load customers and completely ignore the cost increases [elsewhere in the][83] business?
>
> A. I don't -- I don't think -- I don't believe that's the case. But I don't know. I didn't think it would -- just look at the positive side. ***If costs are going up, I think that would be considered as well.***[84] [emphasis added]

Q. Despite Staff's acknowledgment that it would be unfair to "just look at the positive side," isn't that exactly what Staff is proposing to do in this case?

A. Yes, it is. The Staff Rebuttal Report is quite explicit – the only thing that would be tracked and deferred would be positive regulatory lag from large load customer revenues – no offsetting negative regulatory lag would be considered.[85]

Q. What are the primary sources of uncovered costs due to unfavorable regulatory lag?

A. Some of the larger sources of unfavorable regulatory lag faced by the Company are the 15% of depreciation expense and return on qualifying electric plant that

[82] Staff's positive regulatory lag proposal in Evergy's large load tariff case and in this case are very similar.
[83] Text noted as "(indiscernible)" in the Transcript, but readily discernable from the video recording of the hearing.
[84] File No. EO-2025-0154, Tr. (Vol. 2), p. 253 ll. 11-22.
[85] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 21, ll. 11-17.

is unable to be deferred to the PISA regulatory asset,[86] increasing transmission costs due to the ongoing substantial expansion of the transmission network, and general inflationary pressures on labor, equipment, materials, and services.

Q. Are you able to quantify these historical uncovered costs?

A. Over the last five years, Ameren Missouri's earned return on equity[87] has consistently been below the 9.53 percent return on equity most recently authorized by the Commission in File No. ER-2014-0258. During that period, Ameren Missouri's average earned return on equity was just **___** percent, or **___** basis points below the return on equity most recently authorized by the Commission. This represents an average of over **___** million per year in costs the revenue requirement used to set rates did not cover.[88]

Q. Does Ameren Missouri expect that it will continue to experience significant uncovered costs due to unfavorable regulatory lag?

A. Yes, unless the primary sources of unfavorable regulatory lag referenced above are addressed either by the Commission or through new legislation, we expect that future uncovered costs will continue to exceed **___________** per year, consistent with our recent historical experience, and will likely grow over time due to increasing levels of infrastructure investment.

Q. Please provide an example to illustrate the significant level of uncovered costs associated with a large capital investment despite PISA helping to offset a portion of the regulatory lag.

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[86] PISA permits deferred recovery of 85% of the depreciation expense and return on rate base for certain property, plant, and equipment placed in service and not included in base rates (§ 393.1400.2(1)).

[87] Per Ameren Missouri's required quarterly surveillance reporting per 20 CSR 4240-20.090(6).

[88] Uncovered costs are calculated as the difference between Ameren Missouri's actual electric operating income per our quarterly surveillance reporting required by and submitted each quarter per the Commission's rules, and the common equity financed portion of our rate base multiplied by the 9.53 percent return on equity most recently authorized by the Commission in File No. ER-2014-0258.

A. Below is an example of the regulatory lag faced by Ameren Missouri on a hypothetical $2 billion capital investment in a 1,600-MW simple-cycle natural gas energy center with an estimated 45-year useful life.[89] Using the weighted average cost of capital ordered by the Commission for purposes of calculating PISA deferrals in Ameren Missouri's most recent rate review,[90] I have calculated the level of uncovered costs due to the 15% of the return and depreciation on the capital investment not included in the PISA regulatory asset. Assuming the project is placed in service shortly before the true-up date in a rate case and the investment is subject to only 5 months of lag until the new rates incorporating the investment become effective,[91] Ameren Missouri will still experience $11 million in unfavorable regulatory lag, and that is on just that one investment with optimal timing of its in-service date. If Ameren Missouri is unable to perfectly time a rate case in order to align the true-up date with the project's in-service date, the uncovered costs will increase rapidly as shown in Table 4 below.

Table 4– Regulatory Lag on Generation Investment with Different Rate Case Timing

Project In-Service Date	Months of Lag	Uncovered Costs
At true-up date	5 months	$11 million
6 months prior to true-up date	11 months	$25 million
12 months prior to true-up date	17 months	$39 million

[89] Ameren Missouri plans to add 1,600 MWs of natural gas-fired simple-cycle generation by 2030, which includes the 800-MW Castle Bluff Natural Gas Project and the 800-MW Big Hollow Natural Gas Project.
[90] File No. ER-2024-0319.
[91] For example, in Ameren Missouri's most recent electric rate case (File No. ER-2024-0319), an investment placed in service prior to the December 31, 2024 true-up date would have experienced approximately 5 months of regulatory lag before new rates became effective in June 2025.

The above example does not account for unfavorable lag arising from the 15% of investment to which PISA does not apply on the balance of the $16.2 billion, five-year plan Ameren Missouri submitted to the Commission as required by the PISA statute in February of this year, which includes continued investments to replace aging transmission and distribution infrastructure and otherwise to enhance grid reliability and resiliency. That plan incorporates hundreds of different projects, all with different in-service dates. Therefore, it would be impossible to time each project perfectly with the true-up date in a rate review. Using the above illustrative example, one can extrapolate this outcome across a cumulative investment of over eight times this size over the next five years under that plan to see that Ameren Missouri will continue to experience significant uncovered costs in relation to its capital investments.

Q. Are there any other omissions from Staff's analysis that paint an overly rosy picture of the positive regulatory lag the Company may stand to benefit from?

A. Yes. Staff's attempt to quantify $582.7 million[92] in positive regulatory lag related to a hypothetical 500 MW LLCS customer is drastically overstated due to Staff's erroneous assumption that 23% of total LLCS base rate revenues over the entire term of their 16-year Electric Service Agreement ("ESA") would be received during an assumed initial four-year period that would occur prior to any LLCS customer revenues being reflected in a rate case. Staff's hypothetical example is extremely flawed and drastically overstates the potential positive regulatory lag for several reasons.

First, Staff makes an erroneous assumption that, instead of gradually ramping up to their full demand over a number of years as is expected by both the Company and all of

[92] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 20, l. 9, filed September 5, 2025.

the potential LLCS customers I've spoken with, the hypothetical LLCS customer will instead immediately begin taking service at their full anticipated demand. Appropriately factoring in a realistic ramp up period would substantially reduce the proportion of LLCS customer revenues expected to be received in the first four years of its ESA.

Next, Staff makes a second completely unrealistic assumption when it assumes that the Company will not have any rate cases until the end of that initial four-year period.[93] Under the PISA provisions of SB 4, the Company would lose the ability to make PISA deferrals once the 2.25% statutory rate cap has been exceeded. Given the significant investment levels necessary to provide for the required transition of our generation fleet, it is a practical reality that the statutory PISA cap will necessitate the Company filing a general rate case more frequently than the four-year period between rate cases assumed by Staff in its drastically overstated estimate of positive regulatory lag. Additionally, in the highly unlikely event that the Company was not otherwise forced to file a general rate case prior to the end of the four-year period due to the statutory PISA cap, a party or the Commission on its own motion can file a complaint case that would result in the implementation of new base rates if the then current base rates were found to be unjust and unreasonable.[94] Assuming more frequent rate cases in line with our recent historical experience would result in LLCS customer revenues being reflected in rates far sooner than the end of the first four years of such large load service.

Finally, in those intervening rate cases during which the large load customer was ramping up, invariably the LLCS customer revenues would be considered for annualization

[93] The Company would lose the benefit provided by the FAC if a general rate case is not filed at least every four years.
[94] Section 393.140(5) RSMo.

and normalization based on the facts and circumstances that are known and measurable as of the true-up date of a general rate case. Such regulatory adjustments would further reduce the positive regulatory lag the Company would experience during the ramp up of large load customer usage to full load relative to Staff's overly simplistic reliance on annual revenues and a four-year period without rate cases in its analysis.

Q. You mentioned that a large part of Staff drastically overstating the potential positive regulatory lag from LLCS customer revenues is due to Staff making an erroneous assumption that the hypothetical LLCS customer will immediately begin taking service at their full anticipated demand rather than gradually ramping up to their full demand over a number of years. Has Staff acknowledged that a more reasonable assumption would be to factor in a realistic ramp up period?

A. Yes. In Evergy's large load tariff case, Mr. Busch testified:

> Q. If Evergy gets one or more large load customers to come onto its system in the next few years, what would be your expectation regarding whether such customer's load will be at its ultimate peak demand on day one of their operations versus whether that demand would likely ramp up over a number of years?
>
> A. **It's my understanding that these loads ramp up over a series of up to five years**, I believe.
>
> Q. It's, generally, not the case -- let's say we have a 500-megawatt facility that's always going to be used, it's generally not the case that on day one with a data center under large loads open that its operating at 500 megawatts, isn't that right?
>
> A. That's my understanding.[95] [emphasis added]

Q. Staff also differentiated LLCS lag from what it characterizes as "ordinary" favorable regulatory lag associated with customer growth by suggesting

[95] File No. EO-2025-0154, Tr. (Vol. 2) p. 258, l. 24 to p. 259, l. 12. Mr. Busch's expectation is correct and fully consistent with the discussions we have had with prospective customers.

that LLCS revenue will not have offsetting revenue requirement increases. Do you agree with Staff's assertion that favorable regulatory lag is only acceptable when offset by corresponding increases to the revenue requirement?

A. Absolutely not. Staff's assertion that favorable regulatory lag from attracting new sources of revenue is only acceptable when offset by corresponding unfavorable regulatory lag is paradoxical. This is the same as arguing that favorable regulatory lag should not exist at all and directly contradicts Staff's prior testimony that "Regulatory lag can either increase or decrease a utility's actual earnings performance compared to its authorized rate of return in between rate cases. It can be beneficial to customers, as well as to utilities."[96]

Q. Is Staff's claim that there will be no offsetting revenue requirement increases even accurate?

A. No. The acceleration of generation investments will create larger amounts of unfavorable regulatory lag than the Company would otherwise experience. There are also other categories of costs that are likely to increase with large load service. For example, MISO load-based transmission charges, which are for the most part not included in the FAC or any other tracking mechanism or rider, will increase along with the increase in load. Under Staff's proposal, the utility would be forced to absorb these cost increases while the revenues that could cover them would be deferred to a regulatory liability for future return to customers. This is unfair.[97]

[96] File No. ER-2024-0319, Keith Majors Rebuttal Testimony, p. 3, ll. 19 – 21.

[97] It is made even more unfair by Staff's consistent and aggressive opposition to utility proposals to establish a transmission cost tracker due to the ongoing significant unfavorable regulatory lag electric utilities in Missouri face from rising transmission costs, unfavorable regulatory lag that is expected to continue. See File Nos. ER-2010-0356, ER-2012-0174, ER-2014-0130, ER-2021-0312.

Q. Outside of your concerns with Staff's one-sided approach to addressing regulatory lag, do you have any other concerns with Staff's proposed accounting treatment for LLCS customer revenues?

A. Yes, I have one other very significant concern with Staff's proposed accounting treatment, namely that it utilizes an extremely unconventional rate making approach, the effect of which is to massively delay the benefit that other customers will receive from the LLCS customer revenues. For the Generation Demand Charge, the Variable Fixed Revenue Contribution and the Stable Fixed Revenue Contribution, Staff is proposing that "The revenue recorded to the regulatory liability account will not be treated as revenue in setting rates."[98] Instead, Staff is proposing that the regulatory liability from deferring these revenues "would offset production ratebase, and be amortized over a 50-year period."[99]

This is an extreme deviation from traditional ratemaking, the significance of which should not be ignored. Staff is literally saying that retail revenues from the provision of electric service should not be treated as retail revenues from the provision of electric service in rate cases. Under normal ratemaking, these revenues offset the revenue requirement dollar for dollar in real time. Staff proposes to take the benefit of current period revenues related to the provision of current period service away from current customers, and to spread them out to customers over decades into the future. This is utterly non-sensical and is a substantial deviation from foundational ratemaking practices.

[98] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, Appendix 2, Staff Schedule 1, p. 4, ll.8-10, filed September 5, 2025.
[99] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 21, l. 17, filed September 5, 2025.

While this makes no sense on its face, it is also contradictory with Staff's own apparent concern that the normal application of a historical test year in Missouri's cost of service ratemaking framework could result in a relatively short period[100] between when the Company begins to recognize LLCS customer revenues and when those revenues are reflected in a rate case and start to benefit other customers. That Staff would simultaneously propose that other customers will need to wait 50 years to receive the full benefit from the LLCS customer revenues is unimaginable to me. And Staff has not articulated exactly how much higher rates will be in the near term given the delay of reflecting the benefit of potentially billions of dollars of large load retail revenues as an offset to current revenue requirements used to set rates (since Staff appears to propose that on an ongoing basis these revenues will not be treated as revenues in rate cases, and therefore revenues will accumulate to massive levels over time), but it is reasonable to conclude that the impact would be staggering. In contrast to Staff's proposal to trickle these benefits into the revenue requirement over 50 years, under the Company's proposal the LLCS customer revenues will be treated as revenue in setting rates and other customers will see the full benefit from the LLCS customer revenues starting with the effective date of rates in the Company's next rate case.

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[100] Over the recent past, the Company has filed a rate case approximately every two years and has an obligation to file a rate case no less often than every 4 years due to its use of the FAC. Further, if at any time the Commission were to suspect that the Company's rates were unjust or unreasonable, it may file a utility rate case “upon its own motion or upon complaint" (RSMo §393.140(5)).

VIII. STAFF AND OPC'S FAC DISCUSSIONS ARE FROUGHT WITH MISUNDERSTANDINGS OR MISREPRESENTATIONS AND THEIR RECOMMENDATIONS WOULD RESULT IN A COMPLETE MESS IF IMPLEMENTED

Q. Please provide an overview of the testimony of Staff and OPC related to the FAC tariff, and its impact on and implications for large load service.

A. Staff and OPC have fixated on the FAC in both this case and Evergy's large load tariff case (File No. EO-2025-0154) as a potential source of "subsidy" of large load customers by existing customers and/or a claimed "double-recovery" by the utility. When I say that they fixate on the FAC, I would note that a search on the term FAC in the Staff Rebuttal Report identifies 100 different occurrences of the term. Yet a search for the term "securitization," another Rider similar to the FAC where potential subsidies between large load customers and existing customers could arise – except in the case of securitization the subsidies will unambiguously flow from large load customers to the *benefit* of existing customers – identifies exactly *zero* mentions of the term. Why Staff fixates on potential subsidies of large load customers in the FAC while failing to even identify or acknowledge the certain subsidies that will exist through the securitization rider to the benefit of existing customers is completely inexplicable, unless the Staff is consciously attempting to point only to claimed detriments from large load customers.[101]

Staff and OPC's explanations of the FAC are in many cases errant, incomplete, misleading, or lacking in critical context. The various allegations raised by Staff and OPC lead them to make various recommendations related to actions they suggest the Commission take to remedy some of the purported harm that they suggest may arise

[101] OPC witness Mantle's rebuttal testimony similarly includes 35 references to the FAC and exactly zero references to the securitization rider.

through the workings of the FAC. Adoption of their recommendations, however, would create far more problems than they would solve.

At various points in their testimony in this case and in Evergy's parallel large load tariff case (File No. EO-2025-0154) Staff and OPC make misleading or inaccurate claims related to the FAC including:

1. [P]rior to a rate case recognizing the addition of an LLCS customer, essentially all incremental expenses associated with that LLCS customer will flow through the Fuel Adjustment Clause (FAC), however, all revenues from the LLCS customer will flow to shareholders.[102]

2. Without addressing additional revenue requirement from new power plants, through the operation of the FAC, for every 876,000 MWh of new load, the addition of an LLCS customer will raise the bills of existing Ameren Missouri customers approximately $22 million, each year, from the time the customer comes on to the system until the customer's load is recognized in a rate case.[103]

3. Revenues that are not realized in rate cases cannot offset rate increases and FAC increases.[104]

4. Under any rate structure, until the next rate case, it is necessary to create a regulatory liability in the amount of LLCS customer wholesale energy expenses that are included in the FAC, to prevent double-recovery of those expenses.[105]

5. Ameren Missouri will recover substantial portions of the LLCS customer's cost of energy through the FAC and fully recover that cost of energy through LLCS rates.[106]

6. Adding large load customers will increase FAC cost components, but it will not change FAC revenues.[107]

7. Following the first rate case after a LLPS customer is added, if all customers are included in the FAC, the amount of fuel included in the base rates for the non-LLPS customers will increase as will the FAC base factor. Non-

[102] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 3, ll.22-25, filed September 5, 2025.
[103] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 4, ll. 3-7, filed September 5, 2025.
[104] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 13, l. 3, filed September 5, 2025.
[105] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 25, ll. 3-5, filed September 5, 2025.
[106] File No. ET-2025-0184, *Staff Recommendation/Rebuttal*, p. 27, ll. 8-9, filed September 5, 2025.
[107] File No. ET-2025-0184, Lena M. Mantle Rebuttal Testimony, p. 2, ll. 15-16.

LLPS customers will continue to subsidize LLPS customers through the FAC since the increased FAC costs will be charged all customers.[108]

8. In the first FAC recovery period after a LLPS customer reduces load or leaves the system, non-LLPS customers will end up paying the extra cost incurred over the previous accumulation period by the LLPS customer. The subsidization by non-LLPS customers will not end until all the costs of the LLPS customer has been paid by the non-LLPS customers.[109]

Q. Please address the first misleading or inaccurate claim, that is, claims about FAC impacts prior to the conclusion of a rate case that accounts for a large load customer's load.

A. Staff's first statement is simply false. This is because the mechanics of the FAC recognize that a certain portion of the revenues derived from application of the base rates paid by any customer, including a large load customer, exist to cover the net base energy costs that were included in the revenue requirement in the previous rate case, that is, this portion of net energy costs do not flow through the FAC but rather, are covered by base rates. This is a technical, but *critical*, point that Staff either fails to understand or fails to acknowledge and it causes the Staff to grossly overstate the net energy costs that non-large load customers would pay prior to when large load customer load has been accounted for in setting base rates.

To grasp the concept, it is necessary to examine the formula contained in the FAC through which the FAR (Fuel Adjustment Rate that is charged to customers) is determined. The formula contained in the FAC is as follows:

$$FAR_{RP} = [(ANEC - B) \times 95\% \pm I \pm P \pm TUP]/S_{RP}$$

[108] File No. EO-2025-0154, Lena M. Mantle Surrebuttal Testimony, p. 2, ll. 18-22.
[109] File No. EO-2025-0154, Lena M. Mantle Surrebuttal Testimony, p. 2, ll., 23-27.

ANEC in this formula stands for Actual Net Energy Costs. This is the term where the increases in net energy costs that arise from serving new load (manifest as either an increase in purchased power or a decrease in off-system sales) are captured. And it *is true* that this term will result in increased costs flowing into the FAC when new large load service is initiated. However, Staff's statement is premised essentially on the notion that the increase in costs reflected in the term ANEC is the entirety of the impact of large load customers on the FAC. It is not. Why? Because Staff completely ignores the term B in the FAR formula above, which inherently recognizes that the Company has received some base rate revenues from each customer, including large load customers coming onto the system before their loads are accounted for in a rate case, that are intended to cover the net energy costs incurred to serve the customer. The revenues reflected in the term B offset the higher costs in ANEC. This is readily visible in the formula, where B is subtracted from ANEC. And it is this difference (subject to the FAC sharing percentage) that sets the FAR, the rate paid by *all* customers (including a new large load customer) under the FAC. Consequently, it is simply not true that "essentially all incremental expenses associated with that LLCS customer will flow through the FAC, however, all revenues from the LLCS customer will flow to shareholders," since only the *difference* between ANEC and B does. This is the same phenomenon that I identified in walking through Staff's errors in its "net harm" analysis.

As I pointed out above in my Figure 10, the chart Staff displayed in its rebuttal Report on page 4 (and that is depicted in my Figure 7 above because it is from the Staff workpaper) which purports to show that virtually all of the increase in net energy costs that arise from service to this large load customer is being recovered from existing customers is wrong, and wrong by more than $50 million. The reason it is wrong is because that more than $50 million that Staff depicts as being paid by non-large load customers will in fact be covered by large load customer base rate revenues and will never flow through the FAC at all, for the reasons I just explained (only the *difference* between ANEC and B flow through the FAC). Existing customers will not pay "essentially all" of these costs, but the large load customer itself pays a majority of them (and also the Company absorbs some of them as a result of the 95/5% sharing in the FAC). Specifically, the large load customer pays $56.9 million of the net energy cost increase, other customers pay $43 million, and the Company bears $2.5 million.

Q. Please address the second misleading or inaccurate claim, which also makes claims about FAC impacts prior to the conclusion of a rate case that accounts for a large load customer's load.

A. This statement by Staff is another manifestation of the same error I just discussed. Staff's claim that, in this hypothetical scenario of a 100 MW large load customer addition, existing customers would pay an increase of $22 million through the FAC is wrong by the amount associated with Staff's failure to recognize the large load customer's impact on the term B in the FAR formula. I corrected this error above (there it was a correction of a different Staff hypothetical, a hypothetical 500 MW large load customer). But the same dynamic exists in Staff's claimed standalone FAC impact of a 100 MW customer. When the formulas in Staff's workpaper are corrected for this 100 MW hypothetical in exactly the manner I described above in connection with the Factor B discussion, the $22 million impact that Staff identifies as arising through the FAC as a result of the service to the 100 MW customer is reduced to approximately $11 million, since just as was the case with respect to Staff's first misstatement, the large load customer itself will pay about $12.5 million of the net energy cost increases via its base rates due to Factor B. Staff overstated the impact approximately by a factor of 2.

Q. Please address Staff's third inaccurate or misleading claim.

A. Practically speaking, it is simply not true that the only way new large load customer revenues can offset rate impacts to existing customers is for a rate case to reflect those revenues as an offset to the revenue requirement and in any event, Staff's suggestions related to the impact of potential for delay in getting large load revenues reflected in rates is overstated. Staff's claim is premised on the impractical scenario where the Company says out of rate cases for a full four-year period, which it has not done for the past twenty years and which I do not expect it will do in the future, notwithstanding some large load revenues as large load customers ramp-up operations. The Company will almost certainly still have to have more frequent rate cases due to the level of investment in infrastructure it is placing into service, notwithstanding the existence of PISA (there remains full lag on 15% of that large investment), and in consideration of other cost increases, like transmission charges. But I'll nevertheless play along with Staff's assumption for a moment. If Staff were right, wouldn't the very fact that customers would experience *four years of flat base rates* represent a very real form of benefit to existing customers that would have been enabled by the large load revenues? Absent the positive regulatory lag that enabled the Company to avoid a rate case (in Staff's unrealistic view of the world), customers would have had higher rates and higher bills – i.e., the large load revenues offset rate increases that would have *otherwise occurred*. So even if Staff were right (it isn't) about rate case intervals and that the revenues from large load customers would not have directly impacted the *calculation* of all customers' rates, the existence of those revenues would have allowed existing rates to be maintained at a level that is less than they otherwise would have been had the Company needed to file a new rate case, i.e., large load revenues would have served to lower all customers' bills below the level they would have been had these additional rate cases occurred.

Q. Please address Staff's fourth inaccurate or misleading claim that there is some kind of "double-recovery."

A. Staff's claim that operation of the FAC results in "double-recovery" is false. The FAC results in the Company *exactly* recovering its actual net energy costs (aside from the impact of the 95/5% sharing contained in the FAC).[110] Staff is apparently confused, and what I believe is confusing Staff into making this allegation of double-recovery is simply the fact that the Company will experience favorable regulatory lag from the portion of its *base rate revenues that cover other non-fuel costs*, while also being allowed to actually recover its real net energy costs dollar for dollar (other than the 5% it shares) through the FAC. Aside from the sharing, there is no question but that the Company will receive revenues to cover all of its *net energy costs* – base rate revenues to recover that portion baked into base rates (Factor B) and FAC recoveries to recover the difference – but the Company won't receive a penny more than that in relation to net energy costs. What it will receive are new large load revenues that in the scenario in question have not yet been baked into base rates which will cover non net energy costs. Staff could argue that this is an "over-recovery" of those costs, but it is not a double-recovery of net energy costs. And

[110] Which Staff and OPC have advocated for over the years, and by its operation will make the Company absorb rather than recover some amount of the increase in net energy costs caused by adding large load customers.

as I discussed at length in connection with my regulatory lag testimony, it is completely fair for the Company to benefit from some favorable regulatory lag given the significant and chronic negative regulatory lag that impacts the Company almost constantly, which the Company can just as validly argue causes an under-recovery of its non-net energy costs.

Q. Please address Staff's fifth inaccurate or misleading claim.

A. This claim is just another way of claiming there is a "double recovery," which is false, as I just discussed. The Company will not fully recover its net energy costs through its base rates, and will only recover that portion that was not covered by base rate revenues through the FAC (again, Staff's failure to properly apply or understand term B). It is the combination of its base rates that are designed cover such costs and the FAC (subject to the 5% sharing) that provide for recovery of the Company's net energy costs. There simply is no double recovery.

Q. Please address the sixth inaccurate or misleading claim on your list, this one from OPC.

A. It's not clear what exactly Ms. Mantle means when she says "[a]dding large load customers… will not change FAC revenues" but the claim is wrong. As earlier explained, large load customers will contribute base rate revenues that flow into the FAC through the term B, and they will also pay FAC charges (and thus contribute *revenues via the FAC*) by application of the FAR (the "FAC rate") applied to their bill. It does not matter when they take service – whether before their load has been baked into base rates or after that point in time – because the FAR applies to all of the kilowatt-hours they consume.

Q. Please address the seventh inaccurate claim, this one again by OPC witness Mantle.

A. Ms. Mantle's claim of subsidy through the FAC after the first rate case that included a large load customer is a complete mischaracterization that I will discuss later in this section of my testimony.

Q. Please address the eighth inaccurate or misleading claim on your list, which is also from OPC.

A. Ms. Mantle here identifies some potential (very minor) "harm" that could occur sometime in the future if the large load customer's load reduces or *goes away* in the future, but she fails to acknowledge the certainty that this phenomenon will work in reverse to the *benefit* of existing customers when the large load *initiates* service, as I will also discuss later in this section of my testimony.

Q. As technical as this topic is, it is also very important and is filled with inaccuracies in Staff and OPC's testimony. Will you please explain what will happen through the FAC at various points in the life cycle of a new large load customer as simply as you can so that the Commission has a complete picture?

A. Absolutely. On day 1 of new service to a large load customer, that large load customer will begin paying charges on every kilowatt-hour it takes by application of the then-current FAR, through which the FAC is recovering net energy costs that arose in a *prior* Accumulation Period under the FAC *during which the large load customer was not taking service*. Assuming the FAR is a positive rate (a charge, which the FAR is an overwhelming majority of the time), the large load customer will start paying for net costs associated with prior service to existing customers, thereby (to use Staff and OPC's terminology) "subsidizing" them, immediately. Table 5 below illustrates this effect assuming a FAR that is in effect associated with a prior accumulation period during which the large load customer did not contribute at all to the net energy costs.

Table 5 – Illustration of Small Initial Subsidy Provided by Large Load Customer through FAC when Initiating Service

FAC Term	No New LL Customer	With New 100 MW LL Customer	Description
ANEC - B	$10,000,000	$10,000,000	This is a hypothetical under-recovery of $10 million in net energy costs during a previous period where the new large load was not taking service
SRP	20,000,000,000	20,496,400,000	Approximate retail load in a recovery period with and without a new 100 MW large load customer
FAR	$0.00050	$0.00049	Change in FAR resulting from addition of new load to denominator of rate calculation
Costs Recover From Existing Customers	$10,000,000	$9,757,811	FAR times pre-existing customer load
Costs Recovered From New Large Load Customer	$0	$242,189	FAR times new 100 MW LL customer load

Once the Company files to establish a new FAR through the FAC after the new customer has been taking service during the next Accumulation Period, the next effect is that which is described by Staff, although recall Staff ignored term B, so I had to correct that effect as outlined in my earlier testimony. Assuming the incremental cost of energy that was used by the large load customer is higher than the Base Factor in the FAC tariff (i.e., ANEC goes up more than B in our FAR equation[111]), customers will experience a transient increase in costs through the FAC that allows the Company to recover (but not double-recover) its net energy costs. The effect Staff discussed does exist. Staff simply overstated that effect by roughly a factor of 2 as described earlier. As I mentioned, this is a transient effect that will be resolved as soon as a rate case is filed (which will nearly certainly be much less than the four years later that Staff has unrealistically, but repeatedly, suggested).

It is worth noting, however, that at the same time this transient effect is raising costs through the FAC, a similar but *opposite effect is occurring in Rider SUR*, but on a sustained basis that will persist for a decade or longer, where large load payments under Rider SUR are offsetting costs that: 1) all relate to a time period prior to that customer taking service, and therefore which the large load customer received no benefit from (since they arise from securitizing costs from a power plant that never served them), and 2) other customers would be legally required to pay absent the large load customer paying for them. So, while the FAC does have the potential to pass on higher net energy costs to all customers on a transient basis, Rider SUR, which is completely ignored by Staff and OPC, will also result in *lower* costs to all customers arising from the revenue contributions of large load customers. I discussed this dynamic as an error of omission in Staff's "net harm" analysis earlier in my testimony and quantified the effect as an approximately $48 million benefit to existing customers in that example, which related to a new 500 MW large load customer Staff used in its hypothetical "harm" analysis. That impact would scale linearly, such that for the 100 MW customer in Staff's FAC example, the large load customer would provide roughly $10

[111] It is not mathematically certain that this would always be the case but I will agree it would likely be the case in most instances.

million in benefits to existing customers by paying Rider SUR charges, which closely mirrors and essentially offsets the $11 million in potential higher FAC costs that Staff calculated (when corrected for errors).

Next, I'll discuss what happens when, after the large load customer initiates service, a rate case happens, and the large load customer's load is "baked into" base rates. This is where OPC witness Mantle got the picture terribly wrong when she effectively claimed that there will be an ongoing subsidy from the large load customer through the FAC after the first rate case. That couldn't be further from the truth.

Q. Please walk through the full picture of what happens in a rate case after a new large load customer initiates service.

A. Anytime *any* new load is added to the system, two things are certain to happen that impact the inputs to a rate case: 1) net energy expense increases and 2) retail revenues increase. Net energy expense increases because the Company must generate or procure energy to serve the customer, and that has a cost that will go into the revenue requirement (i.e., net energy costs increase). But the customer will also pay a retail bill and produce revenues that cover some portion of the revenue requirement (i.e., retail revenues increase). Holding infrastructure needs constant, the impact of a new load on other customer rates in a rate case largely comes down to the difference between these two offsetting effects. OPC witness Mantle describes, I believe accurately, that, given the generating resources that the Company owns and operates at any given time, the amount of energy that the Company generates from its fleet does not generally change based on changes in the Company's retail load. If the Company is long generation (i.e., generates more energy than its retail customers consume), it will sell that length into the wholesale market and *realize revenues (off-system sales*) at the market price, which offset its revenue requirement. If a utility in that condition of generation length adds load, it generates the same amount of energy, as Ms. Mantle described, but now sells that same energy at its retail tariff rate to the new customer instead of into the wholesale market. The impact of the load addition is a reduction in revenue at the wholesale market price and an increase in revenue at the retail price. The net of those two changes becomes the impact on other customers' revenue requirement responsibility. If a utility is short generation, meaning that it has more retail load than the energy it generates on an ongoing basis, then it has to buy some power from the market to serve some of its load. If a load is added, it must buy more power from the market, incurring the cost of power at the wholesale market price and selling it to the new load at the retail price. Again, it is the net effect of these two events – the purchase of power at wholesale prices and the sale of that same power at retail prices that impact existing customers' revenue requirement responsibility. Under either of these conditions – a utility that is long or short generation – the net effect of a load addition is the same – the direct impact of a new load initiating service on existing customers' responsibility for covering the utility's revenue requirement is the difference between the retail rate received from the customer for the power, and the opportunity cost of that power which is the wholesale market price. Since[112] retail rates are generally higher than market energy prices – this trade off – i.e., selling energy at retail rather than wholesale will generally drive down the revenue requirement responsibility of existing customers.

[112] For reference, recall that the Company's "all-in" rate per kWh associated with its proposal in this case is approximately 6.0 cents. The average LMP at Ameren Missouri's load CP node – i.e., the relevant market energy price – for the year of 2024 was 2.9 cents per kWh.

Q. What do you think then is driving Ms. Mantle's inaccurate claim that there would be a large load subsidy in the FAC even after the large load customer's load has been baked into base rates after a rate case?

A. The dynamic here has to do with how these two effects show up in a rate case – and again, this dynamic is true for *every* load addition or increase that occurs on the system. The increase in net energy costs experienced due to the higher purchased power expense (or lower off-system sales, depending on whether the Company is short or long generation as discussed above) occurs in a category that is reflected in the net base energy costs used to establish the FAC NBEC and BF. Costs increase inside the domain of the FAC. So it is true that every load addition will cause the net base energy costs (NBEC) to be higher than it otherwise would have been, and it will almost certainly cause the Base Factor (BF) to be higher.[113] However, at the same time the total retail revenues provided by the new load reduce the existing customers' revenue requirement responsibility by what is almost always a larger amount than the increase in NBEC since as noted earlier, the retail rate is usually higher than the wholesale cost of energy. However, this effect will occur entirely *outside* of the FAC. The result of *any* load addition – net base energy costs that are recovered either in base rates or in the FAC are higher, but total rates for all customers are *lower*. Essentially, a benefit that was flowing through the FAC (off-system sales revenue in the instance of a utility that is "long" generation or lower purchased power costs if the utility is "short") is displaced by a larger benefit (retail revenues to cover the revenue requirement) that is manifest outside of the FAC mechanism. The overall picture is one of

[113] An exception to this rule could occur in the unlikely event that the increase in the Company's load – the denominator of the BF calculation was larger than the increase in the NBEC, the numerator of the BF calculation.

net benefit for all customers. The fact that the location of that benefit shifted into a different part of the rate structure – i.e., the benefit was previously derived from wholesale revenues that were in the FAC but is now displaced by a larger benefit of retail revenues, but which exist outside the FAC – doesn't matter – there is a benefit. That is, customers' rates in total are now lower irrespective of the increase in the specific category of costs that fall into the classification that subjects them to the FAC. *This does not mean that the FAC is creating a subsidy.* The FAC-related charges (i.e., the BF and/or the FAR) will have gone up, yes, but the new load is providing *more* benefits through its contribution of retail revenue outside the FAC than would have existed when those benefits were derived from wholesale revenues inside the FAC. It just means the benefit moved to a different part of the rate structure. Table 6 below illustrates this effect with simplified illustrative calculations:

Table 6 – Impacts of New Load Inside and Outside of FAC are Opposite Directions and Do Not Represent a Subsidy in the FAC[114]

		Prior to new customer	After new customer	Description
	Total Revenue Requirement	$1,000	$1,020	New load increases the revenue requiremnent by wholesale cost of power
	Total Retail Revenue at Current Rates	$900	$950	New load provides incremental retail revenue at the current retail rate
Outside FAC	Rate Increase Required	$100	$70	Net benefit of new load reduces the rate increase required for all customers
	Total Retail Load	20,000	21,000	New load increases the total retail load served by the utility
Within FAC	Net Base Energy Cost	$200	$220	Net base energy costs within FAC are higher by wholesale cost of energy to serve new load
Within FAC	Base Factor	$0.0100	$0.0105	Base Factor within FAC is higher due to wholesal cost of energy to serve new load
Outside FAC	Average Total Retail Rate	$0.0500	$0.0486	Total Retail Rate is lower due to net benefit of selling retail instead of wholesale

The upshot of Table 6 is that all customers are better off when the utility can sell at higher retail rates as compared to lower wholesale rates, even if that benefit is delivered through a different part of the rate structure. Ms. Mantle's conclusion that a subsidy persists through the FAC because of higher FAC costs is just flat out inaccurate.

Q. Part of your discussion on this point was premised on holding infrastructure needs constant. In reality, infrastructure investment will be needed to facilitate large load service. Won't it be possible that a subsidy exists when the

[114] This illustration assumes a 1,000 kWh increase in load due to the large load customer, a wholesale cost of energy of $0.02, and a retail rate of $0.05

Company has to accelerate the build of generation that is also in the revenue requirement?

A. It is certainly theoretically possible, depending on the amount and cost of new generation that is built relative to the amount of new revenue to be derived from the new load. However, such a subsidy cannot be ascertained through *an FAC analysis*, and if it were to occur, it would still not result in a conclusion that the FAC was a source of ongoing subsidy that needs to be corrected by tinkering with the FAC itself. The higher costs that would be able to be characterized as a subsidy would primarily be fixed costs of plant and have nothing to do with Ms. Mantle's claims about the role of the FAC after a rate case. The only way to assess whether new generation is likely to cause such a subsidy is to perform a robust and comprehensive analysis such as the risk analysis conducted by the Company and presented in my direct testimony in this case. Such an analysis, grounded in the IRP, evaluates the impacts of *all* major sources of potential cost and revenue impacts, including new generation investment, changes in net energy costs, and changes in retail revenues. That analysis suggested that subsidization of large loads is unlikely to exist at all and is very unlikely to reach a level that would constitute an unjust or unreasonable cost impact on existing customers. OPC conducts no analysis whatsoever on which to make such a claim. And Staff's analysis on this topic – its "net harm" analysis – is in effect a less robust and comprehensive attempt at a risk analysis like that conducted by the Company. But Staff's analysis, once corrected for obvious and significant errors and unreasonable assumptions, also demonstrates a very low likelihood that large load customers would be subsidized by existing customers in any meaningful way. Nothing in any party's analysis suggests a likely subsidy, and certainly not a significant subsidy caused by the FAC that warrants changing that tariff mechanism.

Q. At the outset of your discussion of the FAC issues in this case, you indicated your opinion that changes to the FAC suggested by Staff and OPC would cause more problems than they would solve. Can you please elaborate on the problems that Staff and OPC's "solutions" would cause?

A. Yes. Staff and OPC both at various times recommend changes to the FAC that either result in excluding large load customers from participation in the FAC at all, or the creation of a separate second FAC that segregates large load customers from existing customers. There are only two things that could arise from an attempt to differentiate the FAC treatment of large load customers from all other customers: 1) treatment that would be very clearly discriminatory toward the large load customers themselves, or 2) a complete mess would exist where every single component of the Company's net energy cost would have to be evaluated or allocated to determine whether it was attributable to the large load customer or all other customers.

Q. Why would differentiated FAC treatment have the potential to be discriminatory against the large load customer?

A. One way of "carving out" the impact of the large load customer on the existing customers through the FAC – and while Staff and OPC's proposals are not clear enough to understand for sure, it certainly seems like this is what they have in mind – would be to assign net energy costs to the large load customer based solely on the market cost of energy to serve it. This is blatantly discriminatory given that, under either the Company's or Staff's rate proposals, the large load customer would be paying rates that reflect the fixed costs of the Company's generation fleet. To deprive them of *any* benefit from the energy the Company generates from its fleet that is lower cost than the market when the customer is paying the fixed costs of that fleet is facially unreasonable. The customer would never pay for fuel of the generators it should be able to benefit from but would instead pay higher market prices (given that the generators will be economically dispatched to run almost entirely when their variable (i.e., mostly fuel) costs are lower than the market). This solution must be rejected. While I'm not a lawyer, I suspect it would and could be challenged in a court for the blatantly discriminatory outcome.

Q. You said the alternative to discriminatory treatment of the large load is a "complete mess." What makes you conclude that?

A. The only non-discriminatory way to carve a large load customer out of the FAC when it is served by the exact same fleet as existing customers is to perform a very granular allocation of every single source of cost and revenue that exists in the FAC. The complexity of this would be enormous. Which customer(s) get assigned how much of the cost of the lowest fuel cost resources like the Company's Callaway nuclear energy center? Who pays how much for the highest cost resources? Is purchased power serving all customers equally, and how should it be allocated between the base FAC and whatever mechanism exists separately for the large load customers? This would both be an accounting back-office nightmare, and a recipe for disputes between the customers impacted by the two distinct mechanisms about whether the allocation was appropriate and fair. OPC's counsel referred to the idea of having two FACs a "simple solution" during his opening statement at the Evergy large load case hearing.[115] It is anything but simple, and

[115] File No. EO-2025-0154, Tr. (Vol. 2) p. 109, ll. 11-14.

it must not be adopted. In fact, the only solution that makes any sense is for the FAC to continue to operate in its time-tested manner that fairly allocates the Company's net energy costs to all retail customers (net of the 5% sharing that is absorbed by the Company).

IX. RESPONSE TO MISCELLANEOUS ISSUES

Q. Staff witness Luebbert suggests that large load service is contradictory to Company's past efforts to promote demand side management and energy efficiency under the Missouri Energy Efficiency Investment Act.[116] Do these things represent a contradiction?

A. Not at all. In fact, they are perfectly complementary when one steps back and considers sound energy policy holistically. Staff's implicit suggestion that energy efficiency - making cost effective investments to provide the same level of end use service with less electricity and requiring less new resource additions than would otherwise be required - conflicts with trying to grow the economy and enable the benefits of new investment is completely nonsensical and just plain wrong. The existence of growth in useful applications of electricity does not reduce or eliminate the merits of using that electricity efficiently or avoiding more new resources than would *otherwise* be required. Energy efficiency and demand response programming can make room for new load to be brought onto the system without requiring even more new capacity than would otherwise have been required had we not bothered to utilize energy efficiency programs in the first place. If existing loads were higher because energy efficiency had been foregone, even more new generation would be needed today to serve the demand of large load and existing customers.

[116] File ET-20025-0184, *Staff Recommendation/Rebuttal*, p. 7, l. 20 through p. 9, l. 21.

For example, consider the impact of a decision being made by a utility with an opportunity to run an energy efficiency program that will reduce its load by 500 megawatts ("MW"), and thereby avoid the construction of a 500 MW power plant. Assume that utility's load is 5,000 MW and it has 5,000 MW of generation under control to serve that load (ignoring the need for reserve capacity for simplicity of the illustration). Further assume that the utility is forecasting 500 MW of load growth that can be offset on a cost-effective basis by energy efficiency, but which otherwise would require construction of 500 MW of more expensive generation. If this utility runs the energy efficiency program, it will offset the load growth and still have 5,000 MW of load and 5,000 MW of generation. If it does not run the energy efficiency program, it will have 5,500 MW of load and 5,500 MW of generation. Now assume a 1 GW large load customer wants to seek service from this utility a few years down the road. Whether the utility ran the energy efficiency programs or built the power plant makes absolutely no difference to the reality that it will have to build a power plant to serve the 1 GW of large load, because under either circumstance the utility has just enough generation to cover its load. With the energy efficiency programs, the utility will have 6,000 MW of load and 6,000 MW of generation, and will have built 1,000 MW of new generation. Without the energy efficiency programs, the utility will have 6,500 MW of load and 6,500 MW of generation, and will have built 1,500 MW of new generation. Staff's claim that, in Ameren Missouri's circumstance, it is "effectively erasing the proposed benefit of avoiding generation facility costs" that were avoided by its past investments under the Missouri Energy Efficiency Investment Act is absolutely wrong. Like the hypothetical utility in my example, Ameren Missouri is building less generation than it otherwise would as a result of its successful programs, irrespective of the fact that, with or without those programs, we would have still needed more generation in order to serve a significant amount of large load.

Q. MIEC witness Maurice Brubaker recommends that existing customers should not be excluded from participation in new clean energy riders that the Company proposed for application to new large load customers. Is the Company opposed to opening these programs to existing customers?

A. No. I would note that existing customers are already eligible for the currently approved and operating Rider RSP. The Rider RSP-LLC proposed in this case is effectively the same program, except with small modifications to tailor the service to the conditions of large load customers. To that end, I don't believe that Rider RSP-LLC should be opened to existing customers. But for the other new rider proposals – Rider CCAP, Rider NEC, and Rider CEC, existing large commercial and industrial customers served under Rate 11(M) may also be allowed to participate if the Commission sees Mr. Brubaker's recommendation as appropriate.

Q. Mr. Brubaker, along with Sierra Club witness Caroline Palmer, recommend that large load customers be served under a new service classification, rather than as a subclass of the existing Rate 11(M) tariff. Is the Company opposed to creating a new service classification?

A. No, while the Company's original proposal is reasonable, it would also be reasonable to create a new rate class. If the Commission elects to create a new class, that new service classification should start with the existing rates and service terms reflected in the 11(M) tariff, with the additions that the Company proposed in this case that would be specifically applicable to the large load subclass in its tariff proposal filed with my Direct Testimony in this case.

Q. Various witnesses from different parties provide a variety of recommendations for different thresholds for the size of load that should delineate the large load customer class. What is your response?

A. No party has articulated a compelling reason to deviate from the 100 MW threshold articulated in SB 4. The key determining factor, beyond the plain language of the statute, that should guide the determination of this threshold is the level of load that will have a material impact on the Company's resource adequacy position and its IRP. As a system currently supporting roughly 7,000 MW of demand, thresholds lower than the 100 MW statutory threshold are not likely to call for a change in the Company's Preferred Resource Plan, given the size of incremental generation units the Company typically invests in, as I discussed in my Direct Testimony supporting the Company's proposal to use the statutory 100 MW threshold. Notwithstanding that point, Company witness Arora addresses considerations that may warrant a modest deviation from the 100 MW threshold.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Figure 1- Lange Workpaper (500 MW Tab) Calculation of Summer Demand Determinant for Staff's Net Harm Analysis

SUM =E47*4

	A	B	C	D	E	F
46						
47		MW	100		500	
48	LPS	Load Factor	100%		85%	
49	Customer Charge	$ 412.66	12	$ 4,952	12	$ 4,952
50	LIPP	$ 291.99	12	$ 3,504	12	$ 3,504
51	Energy Charge - Summer	$ 0.04060	292,000,000	$ 11,855,200	1,241,000,000	$ 50,384,600
52	Energy Charge - Winter	$ 0.03710	584,000,000	$ 21,666,400	2,482,000,000	$ 92,082,200
53	Demand Charge - Summer	$ 23.90	400	$ 9,560	=E47*4	$ 47,800
54	Demand Charge - Winter	$ 10.63	800	$ 8,504	4000	$ 42,520
55		Revenue		$ 33,548,120		$ 142,585,576
56		Average $/kWh		$ 0.03830		$ 0.03829
57						
58						

Figure 2 - Lange Workpaper Calculation of Summer Demand Revenue for Staff's Net Harm Analysis

SUM | =E53*$B53

	A	B	C	D	E	F
46						
47		MW	100		500	
48	LPS	Load Factor	100%		85%	
49	Customer Charge	$ 412.68	12	$ 4,952	12	$ 4,952
50	LIPP	$ 291.99	12	$ 3,504	12	$ 3,504
51	Energy Charge - Summer	$ 0.04060	292,000,000	$ 11,855,200	1,241,000,000	$ 50,384,600
52	Energy Charge - Winter	$ 0.03710	584,000,000	$ 21,666,400	2,482,000,000	$ 92,082,200
53	Demand Charge - Summer	$ 23.90	400	$ 9,560	2000	=E53*$B53
54	Demand Charge - Winter	$ 10.63	800	$ 8,504	4000	$ 42,520
55		Revenue:		$ 33,546,120		$ 142,565,576
56		Average $/kWh:		$ 0.03830		$ 0.03829
57						

Figure 3 - Rate 11(M) Tariff Screenshot

UNION ELECTRIC COMPANY **ELECTRIC SERVICE**

MO.P.S.C. SCHEDULE NO. 6 — 7th Revised — SHEET NO. 61

CANCELLING MO.P.S.C. SCHEDULE NO. 6 — 6th Revised — SHEET NO. 61

APPLYING TO **MISSOURI SERVICE AREA**

SERVICE CLASSIFICATION NO. 11(M)
LARGE PRIMARY SERVICE RATE

***RATE BASED ON MONTHLY METER READINGS**

Summer Rate (June through September)(1)

Customer Charge - per month	$412.66
Low-Income Pilot Program Charge - per month	$ 291.99
Energy Charge - per kWh	4.06¢
Demand Charge - per kW of Billing Demand	$ 23.90
Reactive Charge - per kVar	44.81¢

Winter Rate (October through May)(1)

Customer Charge - per month	$412.66
Low-Income Pilot Program Charge - per month	$ 291.99
Energy Charge - per kWh	3.71¢
Demand Charge - per kW of Billing Demand	$ 10.63
Reactive Charge - per kVar	44.81¢

Optional Time-of-Day Adjustments

Energy Adjustment - per kWh	On-Peak Hours(2)	Off-Peak Hours(2)
Summer kWh (June-September)(1)	+0.64¢	-0.37¢
Winter kWh (October-May)(1)	+0.29¢	-0.17¢

(1) Refer to General Rules and Regulations, V. Billing Practices, Section A. Monthly Billing Periods, for specific applicability.

(2) On-peak and off-peak hours applicable herein shall be as specified within this service classification.

*Indicates Change.

Issued pursuant to the Order of the Mo.P.S.C. in Case No. ER-2024-0319.

DATE OF ISSUE May 2, 2025 DATE EFFECTIVE June 1, 2025

ISSUED BY Mark C. Birk (NAME OF OFFICER) Chairman & President (TITLE) St. Louis, Missouri (ADDRESS)

Figure 4 – Staff's Workpaper Corrected for Grossly Understated

Large Load Customer Demand

F53 =E53*$B53

	A	B	C	D	E	F
47		kW	100		500000	
48	LPS	Load Factor	100%		85%	
49	Customer Charge	$ 412.66	12	$ 4,952	12	$ 4,952
50	LIPP	$ 291.99	12	$ 3,504	12	$ 3,504
51	Energy Charge - Summer	$ 0.04060	292,000,000	$ 11,855,200	1,241,000,000	$ 50,384,600
52	Energy Charge - Winter	$ 0.03710	584,000,000	$ 21,666,400	2,482,000,000	$ 92,082,200
53	Demand Charge - Summer	$ 23.90	400	$ 9,560	2000000	$ 47,800,000
54	Demand Charge - Winter	$ 10.63	800	$ 8,504	4000000	$ 42,520,000
55		Revenue:		$ 33,548,120		$ 232,795,256
56		Average $/kWh:		$ 0.03830		$ 0.06253

Figure 5 - Staff Calculation of Ameren Missouri Total Retail Sales

(See also Schedule SMW-S__)

Workbook Views | Show | Zoom | Window

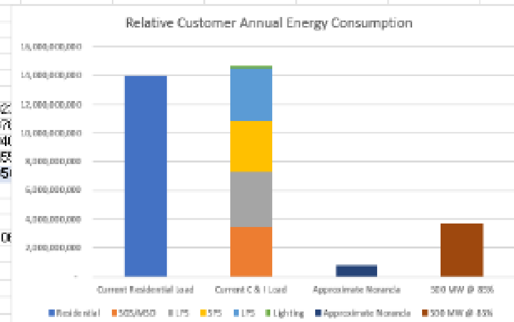
=SUMIF($F$2:$F$376,J$2,$C$2:$C$376)

C	D	E	F
Billing Units	Proposed Rate	Normal Revenue	
2,499,828	$ 9.00	$ 22,498,452	
2,499,828	$ 0.19	$ 474,967	
946,219,047	$ 0.1561	$ 147,704,793	
1,040,565,604	$ 0.1063	$ 110,612,124	
872,706,374	$ 0.0713	$ 62,223,964	
2,859,491,025			Residential
		$ 343,514,301	

G	H	I	J	K	L	M	N	O
	13,270,073	3,231,314	3,684,171	3,399,414	3,684,171			
kWh	**Residential**	**SGS/MSD**	**LPS**	**SPS**	**LPS**	**Lighting**	**roximate Nora**	**500 MW @ 85%**
Energy billing determinants	13,270,072,968	3,231,313,925	3,684,171,231	3,399,414,455	3,684,171,231	-		
Loss Factors to Transmission	1.056	1.056	1.056	1.024	1.012			
Energy at Transmission	14,013,197,054	3,412,267,505	3,890,484,820	3,481,000,402	3,730,091,727	126,369,401	765,624,000	3,723,000,000
	14,013,197	3,412,268	3,890,485	3,481,000	3,730,092	126,369	765,624	3,723,000
	Residential	SGS/MSD	LPS	SPS	LPS	Lighting	Approximate No	500 MW @ 85%
Current Residential Load	14,013,197,054							
Current C & I Load		3,412,267,505	3,890,484,820	3,481,000,402	3,730,091,727	126,369,401		
Approximate Noranda							765,624,000	
500 MW @ 85%								3,723,000,000

C	D	E	F
Billing Units	Proposed Rate	Normal Revenue	
12	$ 9.00	$ 108	
12	$ 0.19	$ 2	
9,756	$ 0.0943	$ 920	
1,996	$ 0.4017	$ 802	
0	$ 0.1063	$ -	
0	$ 0.0713	$ -	
11,752			Residential
		$ 1,832	

G	H
	Residential
Energy @ Trans. July – J	13,686,701,82
Energy @ Meter July – Ju	12,960,891,87
Energy @ Trans. March –	13,647,871,94
Energy @ Meter March –	12,924,121,15
Loss Factors:	**1.05**
	Residential
Weighted Loss Factors	1.0



N	O
nsmissic	Lighting
49,124	133,446,087
44,370	126,369,401
08,460	136,123,919
01,339	126,905,226
.9931	1.056
53,159	
55,682	

C	D	E
Billing Units	Proposed Rate	Normal Revenue
10,619,580	$ 9.00	$ 95,576,220

Figure 6 - Corrected Retail Load Calculation from Staff Workpaper

sform Data | Queries & Connections | Data Types | Sort & Filter | Data To

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=SUMIF($F$2:$F$376,J$2,$C$2:$C$376)
```

C	D	E	F
Billing Units	Proposed Rate	Normal Revenue	
2,499,828	$ 9.00	$ 22,498,452	
2,499,828	$ 0.19	$ 474,967	
946,219,047	$ 0.1561	$ 147,704,793	
1,040,565,604	$ 0.1063	$ 110,612,124	
872,706,374	$ 0.0713	$ 62,223,964	
2,859,491,025			Residential
		$ 343,514,301	
Billing Units	Proposed Rate	Normal Revenue	
12	$ 9.00	$ 108	
12	$ 0.19	$ 2	
9,756	$ 0.0943	$ 920	
1,996	$ 0.4017	$ 802	
0	$ 0.1063	$ -	
0	$ 0.0713	$ -	
11,752			Residential
		$ 1,832	
wers			
Billing Units	Proposed Rate	Normal Revenue	
10,619,580	$ 9.00	$ 95,576,220	
10,619,580	$ 0.19	$ 2,017,720	

G	H	I	J	K	L	M	N	O
	13,270,073	3,231,314	7,212,372	3,399,414	3,684,171			
kWh	**Residential**	**SGS/MSD**	**LGS**	**SPS**	**LPS**	**Lighting**	**roximate Nora**	**500 MW @ 85%**
Energy billing determinants	13,270,072,968	3,231,313,925	7,212,371,801	3,399,414,455	3,684,171,231	-		
Loss Factors to Transmission	1.056	1.056	1.056	1.024	1.012			
Energy at Transmission	14,013,197,054	3,412,267,505	7,616,264,622	3,481,000,402	3,730,091,727	126,369,401	4,161,000,000	3,723,000,000
	14,013,197	3,412,268	7,616,265	3,481,000	3,730,092	126,369	4,161,000	3,723,000
	Residential	SGS/MSD	LGS	SPS	LPS	Lighting	Approximate No	500 MW @ 85%
Current Residential Load	14,013,197,054							
Current C & I Load		3,412,267,505	7,616,264,622	3,481,000,402	3,730,091,727	126,369,401		
Approximate Noranda							4,161,000,000	
500 MW @ 85%								3,723,000,000

G	H	N	O
	Residential	ransmissic	Lighting
Energy @ Trans. July – J	13,686,701,82	49,124	133,446,087
Energy @ Meter July – Ju	12,960,891,87	44,370	126,369,401
Energy @ Trans. March –	13,647,871,94	08,460	138,123,919
Energy @ Meter March –	12,924,121,15	01,339	126,905,226
Loss Factors:	**1.05**	**0.9931**	1.058
		53,159	
		55,682	
	Residential		
Weighted Loss Factors	1.0		

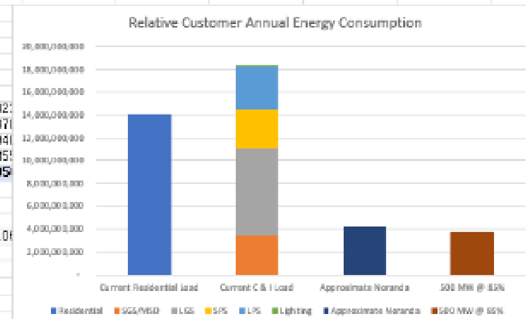

Figure 7 - Staff FAC Workpaper Calculations

C6 | =C5+H5

	A	B	C	D	E	F	G	H
1			This is what would happen without a "Reverse N Factor"	This is what would happen with a "Reverse N Factor"				
2			**No Adjustment**	**With Adjustment**				
3		BF	$ 0.0140	$ 0.0140			LLCS kWh	3,723,000,000
4	*Approximation of Calculations made in rate case*	Annualized Total kWh	28,653,410,908	28,653,410,908	*Thisis the kWh that was considered in the rate case before the large customer started using energy*		New load expense pe	**$ 0.0275**
5		Total Co NBEC	$ 399,906,105	$ 399,906,105			LLCS Cost of Load	$ 102,382,500
6		ANEC	$ 502,288,605	$ 502,288,605				
7		ANEC-B	$ 102,382,500	$ 102,382,500				
8	*Approximation of the Calculations made*	LLCS Adjustment		$ 50,421,830				
9	*when a New FAC rate is made, but this is*	(ANEC - B) - LLCS Adjustment	$ 102,382,500	$ 51,960,670				
10	*shown for an annual basis and without all*	Sharing	0.95	0.95				
11	*details just for the illustration*	FPA	$ 97,263,375	$ 49,362,637			Difference between l	$ 0.0135
12		New Missouri NSI	32,376,410,908	32,376,410,908	*This is the kWh going forward, after the large customer is using energy*		LLCS kWh x Differenc	$ 50,421,830
13		FAR	0.003004143	0.001524648				
14		Excessive Recovery %	95.00%	48.21%				
15								
16	Average BF	0.013956667						
17	Summer	0.01421						
18	Winter	0.01383						
19			No Adjustment	With Adjustment	New Cost of Service	$ 102,382,500		
20		84%	$ 86,078,950	$ 43,686,371	Portion Paid by Existing Customers		$ 86,078,950	
21		11%	$ 11,184,425	$ 5,676,265	Portion Paid by New Customer		$ 11,184,425	
22		5%	$ 5,119,125	$ 2,598,034	Portion Passed on to Ameren		$ 5,119,125	

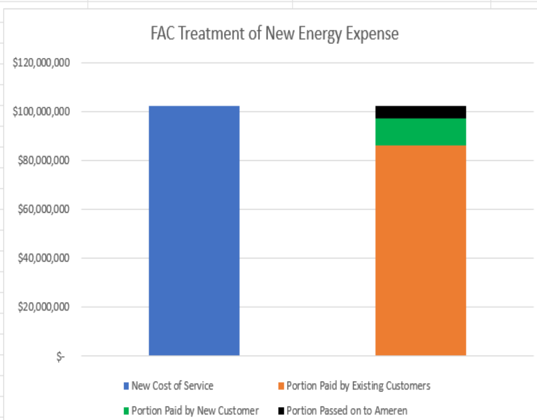

Figure 8 - Staff FAC Workpaper Calculation with First Correction Related to Total Retail Sales

C6 =C5+H5

	A	B	C	D	E	F	G	H
1			This is what would happen without a "Reverse N Factor"	This is what would happen with a "Reverse N Factor"				
2			**No Adjustment**	**With Adjustment**				
3		BF	$ 0.0140	$ 0.0140			LLCS kWh	3,723,000,000
4	*Approximation of Calculations made in rate case*	Annualized Total kWh	32,379,190,710	32,379,190,710	*Thisis the kWh that was considered in the rate case before the large customer started using energy*		New load expense pe	**$ 0.0275**
5		Total Co NBEC	$ 451,905,572	$ 451,905,572			LLCS Cost of Load	$ 102,382,500
6		ANEC	$ 554,288,072	$ 554,288,072				
7		ANEC-B	$ 102,382,500	$ 102,382,500				
8	*Approximation of the Calculations made when a New FAC rate is made, but this is shown for an annual basis and without all details just for the illustration*	LLCS Adjustment		$ 50,421,830				
9		(ANEC - B) - LLCS Adjustment	$ 102,382,500	$ 51,960,670				
10		Sharing	0.95	0.95				
11		FPA	$ 97,263,375	$ 49,362,637			Difference between (	$ 0.0135
12		New Missouri NSI	36,102,190,710	36,102,190,710	*This is the kWh going forward, after the large customer is using energy*		LLCS kWh x Differenc	$ 50,421,830
13		FAR	0.002694113	0.001367303				
14		Excessive Recovery %	95.00%	48.21%				
15								
16	Average BF	0.013956667						
17	Summer	0.01421						
18	Winter	0.01383						
19			No Adjustment	With Adjustment	New Cost of Service	$ 102,382,500		
20		85%	$ 87,233,193	$ 44,272,167	Portion Paid by Existing Customers		$ 87,233,193	
21		10%	$ 10,030,182	$ 5,090,469	Portion Paid by New Customer		$ 10,030,182	
22		5%	$ 5,119,125	$ 2,598,034	Portion Passed on to Ameren		$ 5,119,125	

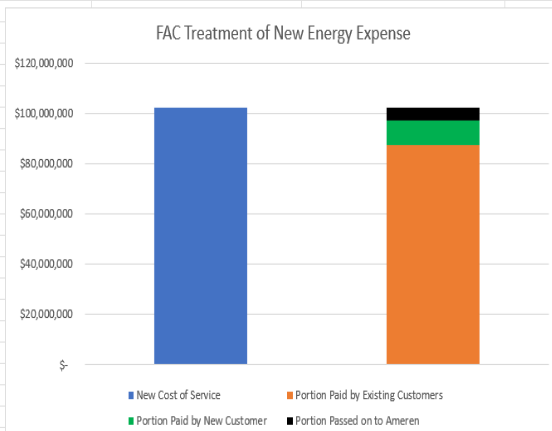

Figure 9 - Staff Workpaper as Corrected – 2nd View

C7 =C6-C5

	A	B	C	D	E	F	G	H
1			This is what would happen without a "Reverse N Factor"	This is what would happen with a "Reverse N Factor"				
2			**No Adjustment**	**With Adjustment**				
3	*Approximation of Calculations made in rate case*	BF	$ 0.0140	$ 0.0140			LLCS kWh	3,723,000,000
4		Annualized Total kWh	32,379,190,710	32,379,190,710	*This is the kWh that was considered in the rate case before the large customer started using energy*		New load expense	**$ 0.0275**
5		Total Co NBEC	$ 451,905,572	$ 451,905,572			LLCS Cost of Load	$ 102,382,500
6	*Approximation of the Calculations made when a New FAC rate is made, but this is shown for an annual basis and without all details just for the illustration*	ANEC	$ 554,288,072	$ 554,288,072				
7		ANEC-B	$ 102,382,500	$ 102,382,500				
8		LLCS Adjustment		$ 50,421,830				
9		(ANEC - B) - LLCS Adjustment	$ 102,382,500	$ 51,960,670				
10		Sharing	0.95	0.95				
11		FPA	$ 97,263,375	$ 49,362,637			Difference betwee	$ 0.0135
12		New Missouri NSI	36,102,190,710	36,102,190,710	*This is the kWh going forward, after the large customer is using energy*		LLCS kWh x Differe	$ 50,421,830
13		FAR	0.002694113	0.001367303				
14		Excessive Recovery %	95.00%	48.21%				
15								
16	Average BF	0.013958667						
17	Summer	0.01421						
18	Winter	0.01383						
19			No Adjustment	With Adjustment	New Cost of Service	$ 102,382,500		
20		85%	$ 87,233,193	$ 44,272,167	Portion Paid by Existing Customers		$ 87,233,193	
21		10%	$ 10,030,182	$ 5,090,469	Portion Paid by New Customer		$ 10,030,182	
22		5%	$ 5,119,125	$ 2,598,034	Portion Passed on to Ameren		$ 5,119,125	

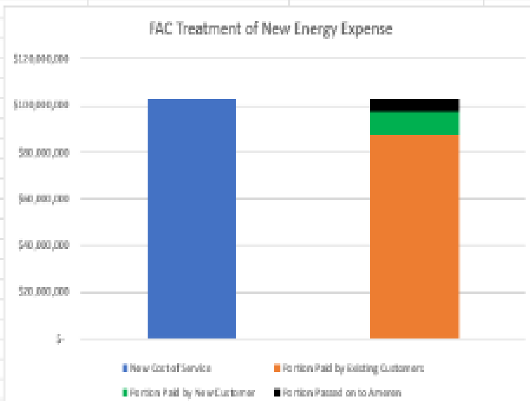

Figure 10 – Corrected Calculation of ANEC – B

in Staff Workpaper FAC Calculations

C7 =C6-C5-H3*C3

	A	B	C	D	E	F	G	H
1			This is what would happen without a "Reverse N Factor"	This is what would happen with a "Reverse N Factor"				
2			**No Adjustment**	**With Adjustment**				
3	*Approximation of Calculations made in rate case*	BF	$ 0.0140	$ 0.0140			LLCS kWh	3,723,000,000
4		Annualized Total kWh	32,379,190,710	32,379,190,710	*This is the kWh that was considered in the rate case before the large customer started using energy*		New load expense	**$ 0.0275**
5		Total Co NBEC	$ 451,905,572	$ 451,905,572			LLCS Cost of Load	$ 102,382,500
6	*Approximation of the Calculations made when a New FAC rate is made, but this is shown for an annual basis and without all details just for the illustration*	ANEC	$ 554,288,072	$ 554,288,072				
7		ANEC-B	$ 50,421,830	$ 50,421,830				
8		LLCS Adjustment		$ 50,421,830				
9		(ANEC - B) - LLCS Adjustment	$ 50,421,830	$ -				
10		Sharing	0.95	0.95				
11		FPA	$ 47,900,739	$ -			Difference betwee	$ 0.0135
12		New Missouri NSI	36,102,190,710	36,102,190,710	*This is the kWh going forward, after the large customer is using energy*		LLCS kWh x Differe	$ 50,421,830
13		FAR	0.00132681	0				
14		Excessive Recovery %	95.00%	0.00%				
15								
16	Average BF	0.013956667						
17	Summer	0.01421						
18	Winter	0.01383						
19			No Adjustment	With Adjustment	New Cost of Service	$ 102,382,500		
20		85%	$ 42,961,026	$ -	Portion Paid by Existing Customers		$ 42,961,026	
21		113%	$ 56,900,383	$ -	Portion Paid by New Customer		$ 56,900,383	
22		5%	$ 2,521,092	$ -	Portion Passed on to Ameren		$ 2,521,092	

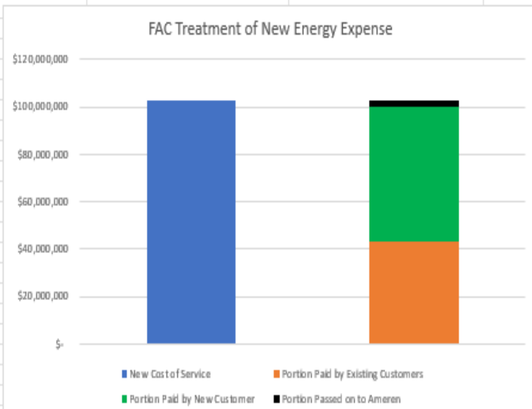

Figure 11 - Staff Workpaper of Cost and Revenue Impacts

of Large Load Addition Over Time

N48 =M48*$F$39

	F	G	H	I	J	K	L	M	N	
35										
36										
37										
38		LLCS Customer Added			Year 1 Rate Case 1	Year 2	Year 3	Year 4	Year 5 Rate Case 2	Year 6
39	1.0612080	$ 144,016,832,350	Revenue Requirement Baseline	$ 3,230,000,000	$ 3,230,000,000	$ 3,230,000,000	############	$ 3,230,000,000	$ 3,427,701,840	$ 3,
40		$ 146,640,540,698	RR With New Plant		$ 3,330,000,000	$ 3,328,326,205	############	$ 3,324,998,454	$ 3,521,046,602	$ 3,
41		$ 134,801,908,254	RR with New Plant and New Customer						$ 3,634,085,155	$ 3,
42		$ 1,946,503,355	Energy & Capacity Expense of LLCS		$ 104,430,150	$ 106,518,753	$ 108,649,128	$ 110,822,111	$ 113,038,553	$
43		$ 1,471,351,194	LLCS Energy Expense in Base Rates						$ 113,038,553	$
44		$ 384,059,918	Total Amount for FAC calculation		$ 51,430,267	$ 106,190,253	$ 107,657,058	$ 108,824,699	$ -	$
45	h year of incurrance>	$ 19,202,996	Shareholder FAC Share		$ 2,571,513	$ 5,309,513	$ 5,382,853	$ 5,441,235	$ -	$
46		$ 39,887,296	LLCS FAC Share		$ 5,038,507	$ 10,403,219	$ 10,546,919	$ 10,661,310	$ -	$
47		$ 324,969,625	Captive Ratepayer FAC Share		$ 43,820,246	$ 90,477,521	$ 91,727,287	$ 92,722,155	$ -	$
48		$ 4,207,208,981	LLCS Base Rate Revenue		$ 240,002,539	$ 240,002,539	$ 240,002,539	$ 240,00[illegible]39	$ 254,692,615	$
49		$ 144,874,709,430	Other Customer Base Rate Revenue		$ 3,330,000,000	$ 3,330,000,000	############	$ 3,330,00[illegible]0	$ 3,379,392,540	$ 3,
50		$ 149,081,918,411	Total Revenue Provided		$ 3,570,002,539	$ 3,570,002,539	############	$ 3,570,002,539	$ 3,634,085,155	$ 3,
51		$ 4,247,096,278	Revenue Provided by LLCS		$ 245,041,046	$ 250,405,758	$ 250,549,458	$ 250,663,849	$ 254,692,615	$
52		$ 145,199,679,055	Revenue from Other Customers		$ 3,373,820,246	$ 3,420,477,521	############	$ 3,422,722,155	$ 3,379,392,540	$ 3
53		$ 1,182,846,706	Compare to Baseline		$ 143,820,246	$ 190,477,521	$ 191,727,287	$ 192,722,155	$ (48,309,300)	$
54		$ 2,300,592,923	Net Contribution of LLCS Customer		$ 140,610,896	$ 143,887,005	$ 141,900,330	$ 139,841,738	$ 141,654,062	$
55					Year 1 Rate Case 1	Year 2	Year 3	Year 4	Year 5 Rate Case 2	Year (
56		$ 144,016,832,350	What Other Ratepayers Would Have Paid		$ 3,230,000,000	$ 3,230,000,000	############	$ 3,230,000,000	$ 3,427,701,840	$ 3,
57	$ 1,182,846,706	$ 145,199,679,055	What Other Ratepayers Will Pay		$ 3,373,820,246	$ 3,420,477,521	############	$ 3,422,722,155	$ 3,379,392,540	$ 3
58		$ 4,247,096,278	What LLCS Customer Will Pay		$ 245,041,046	$ 250,405,758	$ 250,549,458	$ 250,663,849	$ 254,692,615	$
59		$ 904,463,299	Extra to Shareholders		$ 184,431,143	$ 236,038,321	$ 236,968,637	$ 237,565,439	$ -	$
60								**$ 895,003,540**		
61										

Data Response Display - ET-2025-0184 - 0062.0

Request Summary

Submission No.
ET-2025-0184

Request No.
0062.0

Requested Date
10/14/2025

Due Date
10/28/2025

Issue
General Information & Miscellaneous

Other

Requested From
MO PSC Staff (Other)
Lexi Klaus (lexi.klaus@psc.mo.gov)

Requested By
Union Electric Company (Electric) (Investor)
Erin Keenoy (amerenmoservice@ameren.com)

Brief Description
General Information and Miscellaneous

Description
1.) Please provide the supporting calculation or workpaper source for the value of "32846875" in cell J7 of "Regulatory Lag" Tab of workpaper CONFIDENTIAL - General Workpaper. 2.) Please confirm the Cell J6 of "Regulatory Lag" Tab of workpaper CONFIDENTIAL - General Workpaper should include a factor of 1.15 in the calculation of depreciation. If so, what is the basis for it's inclusion?

Request Security
Public (DR)

Response Date
10/28/2025

Response
1) The value represented by $32,846,875 is intended to be generally representative of the net cost of service of operating and maintaining a generation facility for purposes of the illustration discussed in the Report that was not otherwise identified in cells J6:J12. The exact valuation was derived by calculating the sum of the other components in cells J6:J12, and subtracting that value from $100,000,000 for purposes of making the illustration more understandable. 2) Staff confirms that cell J6 incorporates an allowance for net salvage in the calculation of the annual depreciation expenses calculated therein in the amount of 15%. This factor of 1.15 times the original cost divided by the service life is intended to approximate a depreciation rate that includes net salvage.

Objections

Response Security
Public (DR)

Rationale

Attachments

No Attachments Found

ET-2025-0184

Schedule SMW-S3 is Confidential in its Entirety

P

Exhibit No.:	
Issue(s):	Class Cost of Service
Witness:	Nicholas L. Phillips
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2024-0319
Date Testimony Prepared:	February 14, 2025

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2024-0319

SURREBUTTAL TESTIMONY

OF

NICHOLAS L. PHILLIPS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
February 2025

related costs given clean energy legislation passed in the state.[12] While a consensus was not reached among all parties, DEC, the North Carolina Staff, and the Industrial Group reached a settlement that was approved by the North Carolina Commission to move from a 1CP allocator to the A&E allocator precisely because it captures both demand and energy characteristics and many of the fixed cost investments in the system are expected to be related to renewable generation due to the clean energy legislation.[13]

Q. What do you recommend for the allocation of the recent renewable resource acquisitions made by Ameren Missouri on behalf of its customers?

A. I reinforce the recommendation included in my Rebuttal Testimony, namely that the Commission reject Staff's proposal and instead approve Ameren Missouri's proposal for classification and allocation of production plant.

III. RESPONSE TO STAFF POSITION TO INCLUDE WHOLESALE ELECTRIC ENERGY PRICES WITHIN THE DEVELOPMENT OF THE CLASS COST OF SERVICE STUDY

Q. Please discuss Staff's position regarding Wholesale Energy Expenses and Revenues.

A. Similar to Staff's Direct Testimony on the subject, the discussion in its Rebuttal Testimony fails to tell the entire story of how the Staff is using wholesale electric energy prices within its class cost of service study, nor do Staff testimony or workpapers provide sufficient detail regarding the distinction between classifying and allocating costs. Despite this deficiency, the Staff asserts that the Commission has not considered complexities created by Ameren Missouri's (now 20 years of) participation in the MISO

[12] Docket Nos. E-7, Sub 1214 and E-2, Sub 1219.
[13] Docket Nos. E-7, Sub 1276 and E-2 Sub 1300.

energy markets.[14] Staff continues by faulting Ameren Missouri and other parties for failing to consider wholesale energy prices in allocating the cost to serve load and instead relying upon net wholesale costs.[15] Staff concludes that relying upon a study to allocate costs to customers that fails to acknowledge the gross costs and revenues of Ameren Missouri's participation in the MISO market is unreasonable.[16]

Q. Has the Commission previously considered the issue raised by Staff?

A. Yes. In its Final Report and Order in ER-2014-0258 (Schedule NLP-SR2) the Commission found that:

> Furthermore, under FERC Order 668, public utilities must net their MISO-cleared load and generation in each hour and report that net amount as either: (i) sale for resale (i.e. off-system sale under account 447 when the utility's cleared generation exceeds the cleared load, or (ii) a power purchase under Account 555 when the utility's cleared load exceeds its cleared generation. That order states "Netting accurately reflects what participants would be recording on their books and records in the absence of the use of an RTO market to serve their native load." That means that for accounting purposes, Ameren Missouri is required to recognize the distinction between off-system sales, power purchased to supplement its generation and self-generated power.[17]

The Commission further clarified that:

> The evidence demonstrated that for purposes of operation of the MISO tariff, Ameren Missouri sells all the power it generates into the MISO market and buys back whatever power its needs to serve its native load. From that fact, Ameren Missouri leaps to its conclusion that since it sells all its power to MISO and buys all that power back, all such transactions are off-system sales and purchased power within the meaning of the FAC statute. The Commission does not accept this point of view.[18]

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[14] File No. ER-2024-0319, Rebuttal Testimony of Sarah L.K. Lange, p. 17.
[15] Id.
[16] Id.
[17] Schedule NLP-SR2, File No. ER-2014-0258, *Final Report and Order*, p. 113, issued April 29, 2015.
[18] Id at 115.

Q. What was expressed by the FERC in Order 668?

A. The FERC, in Order 668 (Schedule NLP-SR3) stated:

> ***Recording RTO energy market transactions on a net basis is appropriate as purchase and sale transactions taking place in the same reporting period to serve native load are done in contemplation of each other and should be combined. Netting accurately reflects what participants would be recording on their books and records in the absence of the use of an RTO market to serve their native load. Recording these transactions on a gross basis, in contrast, would give an inaccurate picture of a participant's size and revenue producing potential.*** The Commission will, therefore, adopt the proposed accounting for RTO energy market transactions with certain modifications and clarifications as discussed below. The Commission does expect public utilities, however, to maintain detailed records for auditing purposes of the gross sale and purchase transactions that support the net energy market amounts recorded on their books.
>
> Additionally, we clarify that transactions are to be netted based on the RTO market reporting period in which the transaction takes place. For example, if the RTO market in which the transaction takes place uses an hourly period for determining energy market charges and credits, then non-RTO public utilities purchasing and selling energy in the market must net transactions on an hourly basis. Requiring participants to net transactions over the RTO market's reporting period leads to consistent and comparable energy market information for decision making purposes by the Commission and others.
>
> Further, we clarify that the netting of purchases and sales in an RTO energy market is appropriate not only for transactions where participants are required to bid their generation into the market and buy generation from the market to supply their native load, but also in cases where an RTO offers an energy market in which participants may choose to offer all generation to and buy all power from the energy market.
>
> We also clarify that if a participant is a net seller, rather than a net buyer, during a given market reporting period it must credit such net sales to Account 447, Sales for Resale, instead of Account 555, Purchased Power.
>
> Finally, one purpose of this rule is to establish uniform accounting requirements for the purchase and sale of energy in RTO markets. The purpose of reporting of gross information in EQRs, in contrast, is to provide the Commission and the public

> with a more complete picture of wholesale market activities which affect jurisdictional services and rates, thereby helping to monitor for any market power and to ensure that customers are protected from improper conduct. These are not necessarily the same criteria and principles that should be used in establishing uniform accounting requirements. In any event, ***the reporting of wholesale market activity in EQRs falls outside the scope of this rule.***[19] ***(emphasis added)***

Q. Please discuss the except from FERC Order 668 you emphasized above.

A. It is critical to understand that the "buy all, sell all" aspect of the energy markets does not in and of itself cause changes in *how* the utilities serve native load, nor does it cause new costs or revenues to be incurred. As discussed by the FERC, purchase and sales transactions taking place in the same reporting period to serve native load are done in contemplation of each other and should be combined.

Q. What is meant by "done in contemplation of each other?"

A. For a load serving entity that also owns or contracts for generation resources, if only those owned and contracted resources were used to serve native load (no market purchases or sales) the net wholesale cost will be close to zero. This is because, when the energy market clears, it clears at a single marginal energy cost. The difference between each Locational Marginal Price ("LMP") in a given operating interval is related to the costs for congestion and losses.[20] As a consequence, if the accepted generation volumes in a given hour equal the load purchase volumes for the same hour, the revenues paid to the generators will almost entirely offset the cost of the load purchases.[21] The load

[19] Schedule NLP-SR3, FERC Order No. 668, Paragraphs 80-84 (Pages 39-40).
[20] Locational Marginal Price (LMP) = Marginal Energy Cost (MEC) + Marginal Loss Cost (MLC) + Marginal Congestion Cost (MCC)
[21] The market has additional mechanisms (Financial Transmission Rights ("FTR"), Auction Revenue Rights ("ARR"), etc.) vertically integrated utilities such as Ameren can use to further limit exposure to congestion costs and further tightening the difference between generation revenue and load purchases for service of native load. Though it is worth noting that congestion and losses are not new costs, these have

serving entity then would be incurring the cost of fuel, variable O&M, etc. (including losses and congestion) just as it would have absent the presence of the market. The market does enable a more efficient mechanism to economically dispatch the system when it may be more advantageous for a given participant to back down generation and buy energy from the market or generate additional energy to create off-system sales. These would show up as a difference in net wholesale cost for the given interval and would also coincide with an increase or decrease in fuel expense just as it would have, absent the market.

Q. Would it be reasonable to include gross wholesale costs in the allocation of costs as recommended by the Staff?

A. No. In addition to the discussion in my Rebuttal Testimony demonstrating why the approach leads to illogical results when incorporated into the cost study, the MPSC and the FERC have both already weighed in on why it is appropriate for utilities to net these costs, as done by Ameren Missouri in its cost study. Additionally, as I discussed at the opening of this testimony, there is no clear connection between the NARUC Manual and Staff's proposal as it relates to the use of wholesale energy prices within allocation of costs to customers. Given the law requiring the use of allocation methods aligned with the NARUC Manual, the Commission should consider as a threshold question whether the CCOSS put forth by Staff meets the statutory requirements in Missouri before weighing arguments on the (un)reasonableness of the approach. As I discussed earlier, I do not believe that Staff has met the statutory requirement.

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always existed prior to the market and have been included in rates as part of Ameren's cost of service. The MISO market has made these cost components more transparent.

Q. Does the participation in the MISO energy market actually cause new multi-billion-dollar costs and revenues as Staff claims?[22]

A. No. In the last sentence emphasized in FERC Order 668 above, it states that, "Recording these transactions on a gross basis, in contrast, would give an *inaccurate picture of a participant's size and revenue producing potential*." The plain reading of this contradicts Staff's position, i.e. the buy-all, sell-all wholesale energy market transactions, if recorded on a gross basis would actually cause an inflated view of actual costs and revenues rather than, as Staff asserts, be a more accurate reflection wholesale energy transactions. Incorporating this into the CCOSS would thereby distort rather than improve the results.

Q. What do you recommend regarding the use of wholesale energy prices in cost allocation as proposed by Staff?

A. I recommend the Commission reject Staff's proposal and rely on the CCOSS put forth by the Company.

IV. RESPONSE TO STAFF POSITION REGARDING THE SELECTION OF HOURS FOR USE IN THE DEVELOPMENT OF A PRODUCTION DEMAND ALLOCATION METHOD

Q. Staff raises concerns regarding the selection of peak hours for use in a production demand allocator. Please summarize Staff's concerns.

A. At the most basic level, Staff believes that due to Ameren Missouri's participation in the MISO market and its requirement to demonstrate compliance with the MISO's seasonal resource adequacy construct, that the hours used by the MISO in the seasonal resource adequacy construct should be the same hours used to allocate production

[22] File No. ER-2024-0319, Rebuttal Testimony of Sarah L.K. Lange p. 17, l. 9 to p. 18, l. 8.

Exhibit No.:	
Issue(s):	Policy
Witness:	Steven Wills
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2024-0319
Date Testimony Prepared:	February 14, 2025

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2024-0319

SURREBUTTAL TESTIMONY

OF

STEVEN WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
February, 2025

V. CLASS COST OF SERVICE PRODUCTION COST ALLOCATIONS

Q. Staff witness Sarah Lange, on the topic of production cost allocations contained in the Company's Class Cost of Service Study ("CCOSS"), states that "Ameren Missouri sells all of its generated energy…into the integrated energy markets, and Ameren Missouri purchases all of the load requirements of its customers…from the integrated energy markets. It is not reasonable to rely on any study that fails to acknowledge the cost and revenue causation of these market activities".[9] What is your response?

A. Company witness Nick Phillips responds in more depth to this topic, but I also feel compelled to weigh in on this extreme and inappropriate take on the proper allocation of production costs. I can't think of any way to characterize Staff's preferred production allocation method (which it criticizes the Company for not using for its CCOSS) other than as an attempt to break the vertically integrated utility – a utility that plans, owns, and operates its own generation fleet for the very purpose of serving its load and therefore insulates its customers from undo market reliance and price exposure – apart into an apparent merchant generation function and a load serving entity function that relies exclusively on the market, and allocate the impacts of those two functions distinctly, resulting in massive shifts of fixed costs between classes based on nothing but market prices.

Mr. Phillips discussed this in his rebuttal testimony and expounds on the topic further in his surrebuttal testimony. One of the observations he raises in his surrebuttal relates to the concept of netting market purchases and sales for accounting purposes for

[9] File No. ER-2024-0319 Sarah L.K. Lange Rebuttal Testimony, p. 18, ll. 3-8.

vertically integrated utilities that is dictated by FERC rule, and a related Commission ruling in the Company's 2014 electric rate case (File No. ER-2014-0258) related to "true purchased power" and how that concept relates to recovery of transmission expenses in the Fuel Adjustment Clause ("FAC").

If Staff's perspective that wholesale market transactions that otherwise are netted for accounting purposes and FAC inclusion should be discretely treated as *new sources of cost and revenue causation* were adopted by the Commission, it would directly undermine the whole concept of "true purchased power" that underlies the Commission's historical treatment of transmission expense in Missouri FAC's. To the extent that occurred, the Company would and certainly should propose full inclusion of all transmission expenses in its FAC in a future rate review – and the Commission should agree.

VI. MISCELLANEOUS ISSUES

Q. What issue does Staff witness Eubanks take with the recommendation proposed in the direct testimony of CCM witness Hutchinson related to reimbursement of food spoilage and other related expenses associated with power outages exceeding 48 hours?

A. Witness Eubanks raises the concern that such a policy would potentially raise costs for all customers.

Q. Do you agree with her concern?

A. Yes. Longer duration outages such as those that would be the subject of CCM's proposal are overwhelmingly the result of severe storms that cause damage to the system. Such events are beyond the control of the Company, and therefore it would be unreasonable for the Company to have to provide financial insurance to customers

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of New or Modified Tariffs for Service to Large Load Customers.	))))	File No. ET-2025-0184

AFFIDAVIT OF STEVEN M. WILLS

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

Steven M. Wills, being first duly sworn states:

My name is Steven M. Wills and on my oath declare that I am of sound mind and lawful age; that I have prepared the foregoing *Surrebuttal 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 M. Wills
Steven M. Wills

Sworn to me this 3rd day of November, 2025.