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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2024-0319

REBUTTAL TESTIMONY

OF

NICHOLAS L. PHILLIPS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri

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REBUTTAL TESTIMONY

OF

NICHOLAS L. PHILLIPS

FILE NO. ER-2024-0319

I. INTRODUCTION AND PURPOSE

Q. Please state your name, position and business address.

A. My name is Nicholas L. Phillips, and I am a Director at Atrium Economics, LLC ("Atrium"), a management consulting and financial advisory firm focused on the North American energy industry. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina, 29926.

Q. On whose behalf are you filing testimony?

A. I am filing testimony on behalf of Ameren Missouri ("Ameren" or "Company").

Q. Have you previously provided testimony in this proceeding?

A. No.

Q. Have you previously provided testimony to the Missouri Public Service Commission?

A. Yes. I have provided testimony to the Missouri Public Service Commission in the following cases: ER-2012-0166, ER-2012-0174, ER-2012-0175, ER-2014-0258, ER-2016-0179. Additionally, I have provided testimony in approximately 50 regulatory proceedings throughout North America. A full list of my qualifications is attached to this testimony as 2.

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to address recommendations raised by the Missouri Public Service Commission ("MPSC" or "Commission"), Industry Analysis Division Staff ("Staff"), and Consumer's Council of Missouri ("CCM") who both recommend the Commission approve rates that are derived using cost-of-service approaches that depart from industry standard and broadly accepted methods that underly the Company's study. My testimony is narrowly focused on these issues. As such, my silence on any issues raised by parties but not explicitly discussed within my testimony should not be construed as a tacit endorsement of any position.

Q. Which witnesses testimonies are you rebutting?

A. My testimony rebuts Direct Testimony provided by Staff witnesses Sarah L.K. Lange and CCM witness Palmer.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are summarized as follows:

1. I recommend that the Commission approve rates properly classified between demand and energy and that utilize the Average and Excess ("A&E") method to allocate production demand related costs, as proposed by Ameren. In turn, the Commission should reject Staff's proposed method to classify costs using market prices and allocate the majority of production demand related costs using an energy allocator. Staff has not presented compelling evidence demonstrating that cost causative factors have fundamentally changed necessitating a commensurate change in cost allocation. Consequently, modifying the method to classify and allocate production function costs in

this proceeding would lead to unforeseeable and inequitable shifts in revenue apportionment across the customer classes.

2. I recommend that the Commission approve rates that utilize the Minimum Distribution System ("MDS") method to classify and allocate distribution costs and reject CCM's proposal to adopt the Basic Customer Method. I further recommend that the Commission reject CCM's alternative proposal to utilize a MDS with no primary customer component as this would not align with cost causation on Ameren's System.

3. I recommend that Staff's proposed modifications to the classification and allocation of distribution system costs also be rejected. Staff's proposal is fundamentally flawed and cannot be relied upon for setting just and reasonable rates.

4. I recommend that the Commission require as a matter of procedure going forward, if parties file alternative Class Cost of Service Studies ("CCOSS") that are not based on the same CCOSS model filed by the utility that initiated the rate review, those parties should be required to file sufficient detail including but not limited to a fully unbundled breakdown of costs at each step (Functionalization, Classification, and Allocation) within the cost allocation process to ensure full understanding and transparency of alternative models by all parties to the case, as well as the Commission.

Q. How is your Rebuttal Testimony organized?

A. My Rebuttal Testimony is organized by the issues I am responding to. Where there is overlap between responses to multiple witnesses within the same issue, I note that in my response. The general topics I respond to are as follows:

1. Recommendations offered by Staff witness Sarah L.K. Lange related to Staff's proposed alternative method for the allocation of production demand related costs.

2. Recommendations offered by CCM witness Palmer related to CCM's proposed alternative method for the classification and allocation of distribution costs

3. Recommendations offered by Staff witness Sarah L.K. Lange related to Staff's proposed alternative method for the classification and allocation of distribution costs.

Q. Are you sponsoring any schedules as part of your Rebuttal Testimony?

A. Yes. I am sponsoring the following schedules as part of my rebuttal testimony:

- Schedule NLP-RI – Qualifications of Nick Phillips

II. RESPONSES TO RECOMMENDATIONS OFFERED BY STAFF RELATED TO THE ALLOCATION OF PRODUCTION DEMAND RELATED COSTS

Q. Please explain the term "production demand related cost."

A. By production demand related cost, I am referring to those costs included in the Company's cost of service that are assigned to the production function and classified as demand related.[1] Typically, these costs are the fixed costs of generating assets, although with the general movement to add more renewable and zero carbon resources to the electric system, another way to think about production demand related costs are those costs which are capacity and resource adequacy-related costs. This is because historically production demand related costs were often referred to as those production related costs that did not vary with energy production from a resource – such as the fixed costs associated with a coal or natural gas-fired generating asset (whereas the fuel component was production energy related as these costs do vary with energy production). However, renewable energy resources are virtually all fixed costs (that is they do not vary with energy production –

[1] The Cost of Service concepts of Functionalization, Classification and Allocation are discussed in detail in the Direct Testimony of Ameren Witness Thomas Hickman at p. 6 l.16 – p. 7 l.18

save for production tax credits) that are added to the system for both capacity and energy purpose.[2] In this sense, renewable energy resources can be thought of as "swapping steel for fuel" and should not necessarily be fully lumped into demand related costs just because the cost of these resources do not vary appreciably with energy generation. Notwithstanding my last statement, one must also consider the choice of allocators when making these determinations as well given the choice of production allocator may itself include both demand and energy characteristics thus potentially offsetting the need to potentially classify renewable generation facilities as energy related.[3]

Q. What method for allocation of production demand related costs does Ameren propose for use in developing the rates included in its filing in this docket?

A. Ameren proposes the A&E method to allocate production functionalized costs that have been classified as demand related.

Q. Please explain the term "production energy related cost."

A. By production energy related cost, I am referring to those costs included in the Company's cost of service that are assigned to the production function and classified as energy related.[4] These costs predominantly are fuel and purchased power, potentially net of off-system sales revenues. Other costs such as variable O&M and other energy related production costs may also be included.

Q. What method for allocation of production energy related costs does Ameren propose for use in developing the rates included in its filing in this docket?

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[2] Different types of renewable and energy limited resources provide differing amounts of firm capacity to a system based upon penetration levels, system load shapes, time of day, season, and other factors.
[3] The A&E allocator, as I will discuss later, does consider both demand and energy components of each class.
[4] The Cost of Service concepts of Functionalization, Classification and Allocation are discussed in detail in the Direct Testimony of Ameren Witness Thomas Hickman at p. 6 l.16 – p. 7 l.18

A. Ameren proposes a pure energy method to allocate production functionalized costs that have been classified as energy related.

Q. Do you agree with Ameren's Direct testimony position?

A. Yes. I will discuss the specific reasons for my agreement through this section of my testimony. Generally speaking, while Ameren has a stated policy goal to reduce carbon from its system and add renewable energy resources as part of its strategy to facilitate the carbon reduction, the fact is that Ameren's system planning and operations has not materially changed and continues to include, in additional to zero carbon resources, significant additions of dispatchable resources as needed for resource adequacy and firm, reliable energy production as it has in the past. Thus, the drastic change as proposed by Staff (which I will discuss below) is unwarranted. Furthermore, the A&E approach currently utilized is what is known as an "Energy Weighted" allocation method.[5] This results in an allocation of production demand related costs that already considers both demand and energy components. I also agree that the allocation of production energy related costs should continue to be allocated using energy.

Q. Please explain in detail how the A&E method allocates production demand related costs both on demand and energy characteristics.

A. The A&E allocator can be thought of as the weighted average of two components when determining class contributions for allocation of costs. The first component uses average demand which is equivalent to energy and represents each customer class's contribution to the average demand of the system.[6] This component is

[5] 1992 NARUC Cost Allocation Manual at Page 49.
[6] Mathematically total system energy is the sum of energy of all hours of the year. Average demand is the sum of energy across all hours of the year divided by the number of hours in the year. From an allocation, or percentage basis, among customers classes these two numbers are mathematically equivalent.

weighted by the system load factor.[7] The excess component uses each class's non-coincident peak demand in excess of the average demand and this component is weighted by one minus the system load factor. In the instant docket when developing the A&E allocator, Ameren has calculated the system load factor to be 59.7%. Consequently, 59.7% of production demand related costs are currently being allocated on energy. The remainder of the costs are allocated on class demands in excess of their average demand.

Q. How does this differ from a classification of production costs as energy related?

A. The primary difference between the classification and allocation steps within the CCOSS is that classification is applied to functionalized costs at the system level without consideration of each customer class's individual demand and energy characteristics. Once classified, an allocator is then applied to the costs to determine the proportion of the classified cost that would be attributed to each class. Conversely, the allocation factors determined via the A&E allocator weight individual customer class loads by their respective energy and excess demand characteristics to determine the proportion of customer class responsibility for costs.

Q. Please summarize the position and recommendations offered by Staff concerning the allocation of production demand related costs.

A. Staff recommends the Commission adopt a new approach for the classification and allocation of production function costs that is developed by the Staff. It is difficult to assess whether Staff is proposing to effectively use market prices to classify costs between demand and energy or use market prices to reallocate costs between sub-

[7] Load factor is the ratio of average system demand to peak system demand, with a maximum value of 1.0

functional components, as Staff does not adequately describe its proposal in testimony nor does Staff provide a fully unbundled cost of service. Regardless of how one would actually characterize Staff's method, its approach attempts to incorporate facets of Ameren's participation in the Midcontinent Independent System Operator's ("MISO") market and the associated market prices in the basis for developing the classification and allocations for production function costs. Staff also proposes a sub-functionalization of certain production demand related costs into groupings ("Type 1" and "Type 2") based on characteristics of generating assets. Staff proposed to allocate the Type 2 resource solely on the basis of energy and the Type 1 resources on the basis of net demand.[8,9]

Q. Do you agree with Staff's recommendation?

A. No. While I do find it commendable that the Staff is attempting to be forward thinking and looking to ensure that cost allocation and cost causation remain aligned as Ameren transitions its system to one with a greater proportion of renewable energy resources, I do not believe that the approach concocted by the Staff accomplishes the intended purpose of better aligning cost allocation with cost causation; nor do I believe that Ameren's planning and operations have shifted in a material way that would necessitate deviating from well-established and industry accepted practices within this proceeding. In order to achieve a level of predictability in rates and fairness among customer classes, deference should be given to precedent when there is a lack of compelling evidence demonstrating that cost causative factors have fundamentally changed this necessitating a commensurate change in cost allocation.

[8] I discuss the specifics regarding Type 1 and Type 2 resources and their respective allocators later in this testimony.
[9] Net demand as used by Staff are class demands in MISO seasonal peak hours net of Type 2 resource output.

Q. Has Staff presented compelling evidence that the Ameren system planning and operations have changed in a material way since Ameren's last general rate proceeding?

A. No. Staff discusses that Ameren participates in the MISO integrated market and that the resource adequacy paradigm is in the midst of change.[10] Staff also discusses that Ameren has retired several coal-fired generation units in recent years and added wind and solar resources.[11] However, these facts, while true, have not caused differences in the way Ameren plan's or operates its system. By this I mean that participation in an organized energy and capacity market does not change that fact that Ameren Missouri is a vertically integrated electric utility that undertakes Integrated Resource Planning as a means of ensuring it has developed sufficient owned generation resources to meet all of its customers energy and capacity needs. Simply put, the Company generally does not depend on the market to any significant degree as a means of serving its load.[12] It is serving its load in the same way it has for decades. The market is simply there as a more efficient means to pool reserves to increase reliability at lower cost and facilitate economic energy purchases and sales with other generators and load serving entities. The market itself is not a basis for the Company's production cost causation today any more so than it has been for decades. Moreover, the Company's owned and contracted generation assets act as a physical hedge against market prices, yet as I will explain later, the method proposed by Staff introduces market price volatility into the classification and allocation of costs to customers in a way that even if Ameren's cost of service does not change, a change in market prices will cause

[10] File No. ER-2024-0319, Sarah L.K. Lange, Direct Testimony, p. 15, l. 4 through p. 14, l. 8.
[11] Id at FN 24.
[12] Under some circumstances there may be transient periods of modest market reliance due to issues associated with load growth and resource timing.

the revenue apportionment between classes to change. Consequently, it would be premature and unwarranted to implement such a stark change to the allocation of production demand related costs. Additionally, I have specific concerns about how Staff has developed its proposal which I will explain; however, these concerns are secondary given I do not believe the evidence supports consideration of Staff's proposal.

Q. For what purpose does Staff discuss Ameren's participation in the MISO energy markets and how does this impact Staff proposed allocation of production demand related costs?

A. Staff's testimony is somewhat vague in this regard. Staff only mentions the impact of the MISO energy market in the context of Staff's estimates of normalized fuel and purchased power expense net of energy sales revenues.[13] However, Staff's workpapers demonstrated the development of its CCOSS that simulated market-based generator revenues were used also within the development and allocation of production demand related (i.e., largely fixed) costs. Effectively, Staff's uses simulated generator revenues (but at no point discusses why the corresponding and offsetting load purchases are not considered) as the basis to reallocate costs that should be allocated using the production demand allocator and reassigns these costs to its "Wholesale Cost of Energy" subfunction and allocates these costs on the basis of a price-weighted energy allocator, which is not explained in the Staff's testimony.[14] The lack of explanation within Staff's testimony is further compounded due to its workpapers. Staff does not include a full unbundling of costs showing the step-by-step process used to functionalize, classify, and allocate costs

[13] Id at 12 & 13.
[14] Staff's only discussion of the Cost of Wholesale energy and assignment to the classes is limited to one sentence at the Direct Testimony of Staff witness Sarah L.K. Lange at p.19, ll. 5-6. It is also troubling that Staff uses generator revenues as a cost.

which is standard industry practice today. These deficiencies increase the complexity in providing a response to Staff's approach as it is not clear whether this "reallocation of sub-functional costs" is actually intended to be a classification step as one would expect in an embedded cost of service analysis, or if Staff is bypassing the classification step and proceeding directly to allocation of costs to customer classes. The net production demand related costs are then allocated using the "Type 1" and "Type 2" production demand allocators actually described in Staff's testimony.[15]

Q. Please provide a more detailed explanation of Staff's reallocation of sub-functional costs based on simulated market revenues.

A. Within the production function, Staff has actually created three sub-functionalization categories to which it assigns production functional costs: Production Type 1, Production Type 2, and Net MP&T.[16] Generation asset specific costs and those costs that can be reasonably inferred to be related to a specific type of generation asset (type meaning Type 1 or Type 2) are sub-functionalized into those two types. This would include, for example, fuel costs, depreciation expense, O&M, etc. However, production functional costs that are unable to be reasonably attributed to a specific asset type are assigned to the Net MP&T subfunction. This includes costs such as purchased power costs and off-system sales revenue, etc. After this step, Staff's sub-functionalization results in approximately $1.1 Billion of total net expense functionalized as Type 1, $36.7 million as Type 2, and (-$57.9) million as Net MP&T (after removing transmission expenses).

With these sub-functions now created, next Staff uses the results of the production cost simulation developed to support the development of Net Base Energy Costs ("NBEC")

[15] File No. ER-224-0319, Sarah L.K. Lange Direct Testimony, pp. 15-18.
[16] Net Market, Production, and Transmission; Direct Testimony of Staff witness Sarah L.K. Lange p. 1.

to calculate simulated market revenue for each generator[17] and assigns these between Type 1 and Type 2 generation assets. Staff then reduces the Type 1 and Type 2 generation revenue requirement by the simulated generation revenues and creates a new sub-function called "Cost of Wholesale Energy" where the production revenue requirement that was removed from Type 1 and Type 2 due to the netting of simulated generator revenues is reassigned (along with what was previously called Net MP&T). The net result before the consideration of Rate of Return, is that approximately 88% of all production expense is allocated using an energy-based allocator. This is nonsensical given the predominant energy related production expense is fuel and purchase power net of off-system sales, which in Staff's CCOSS is approximately $415 million of the approximately total $1.024 billion of production expense.[18] Furthermore, this approach as I will discuss in detail later, introduces market volatility through the use of simulated wholesale electric energy prices, into the allocation of demand related costs to customer classes when wholesale electric energy prices are in no way related to the cost-causation of the production demand related costs.

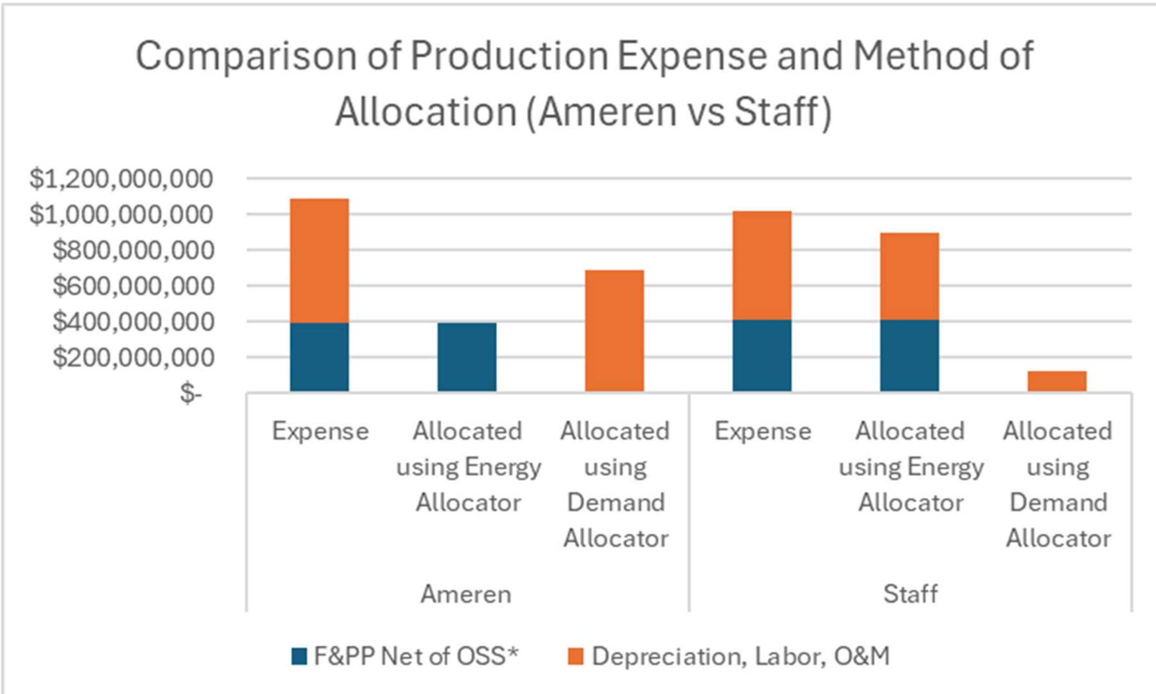
Q. What is the breakdown of production expenses included in Ameren's CCOSS between demand and energy related?

A. Included in Ameren's CCOSS is approximately 64% of production expense allocated on a demand allocator and 36% on an energy allocator, which directly ties to the breakdown of cost classified as demand and energy respectively. The energy related expense is net of off-system sales revenue and in Ameren's CCOSS the net energy expense

[17] The generator revenue is equal to the sum of each generator's hourly MWh output multiplied by the hourly generator LMP calculated within Staff's fuel run.
[18] For reasons I have already discussed, it is unclear what costs Staff has actually classified as demand and energy related.

is approximately $397 million of a total $1.091 billion in total production expense. Figure 1 below compares Ameren's and Staff's total production expense broken down by demand vs energy allocation amounts.

Figure 1



*Due to Staff's lack of a full unbundled cost study, the Fuel & Purchased Power ("FP&P") Net of Off System Sales ("OSS") represent only F&PP Net of OSS for Staff (I also included both Capacity and Energy purchases and sales to make the cost estimates between Staff and Ameren as similar as possible) whereas the figure for Ameren represents all production energy related costs

Q. What is the result of this approach to the customer classes?

A. The result of this approach is that approximately 80% of production demand related expenses are not allocated using the method described by Staff in its testimony and instead are allocated on a (pseudo) energy basis. This results in a dramatic shift of production demand related revenue responsibility between customer classes with no clear reason or explanation for why this is appropriate.

Q. Is there any logical reason why Staff's approach to reallocate almost two-thirds of production demand related expenses using an energy allocator should be used in the determination of class revenue responsibility?

A. No. This does not align with cost causation. Hourly energy market operations are in no way causal to the investment in production plant and production demand related costs. The proper place for consideration of the hourly market operations is through the production cost simulations and net base energy costs. Moreover, Ameren still plans its system to meet its native load obligations. It does not invest in resources for the energy market purposes or wholesale generator revenues. Ameren is not a merchant generation operator. Absent the MISO market, Ameren would still plan its system and serve its customers just as it had done prior to when Ameren joined MISO in 2004. This begs the question that if Ameren has been a participant in the MISO (including in its energy market, which began operations in 2005) since 2004, why is Staff only now attempting to incorporate a merchant generation, buy-all, sell-all approach into cost allocation? It is illogical to attempt to reallocate production demand related costs based on MISO generator revenues when the fundamental operations of Ameren within the MISO energy markets haven't changed in roughly the past two decades Ameren has participated in the market. To do so now would lead to an unforeseeable and inequitable shift in revenue responsibility among customer classes when Staff has failed to demonstrate that cost causative factors have fundamentally changed.

Q. Why did you not include the return on rate base in the discussion above?

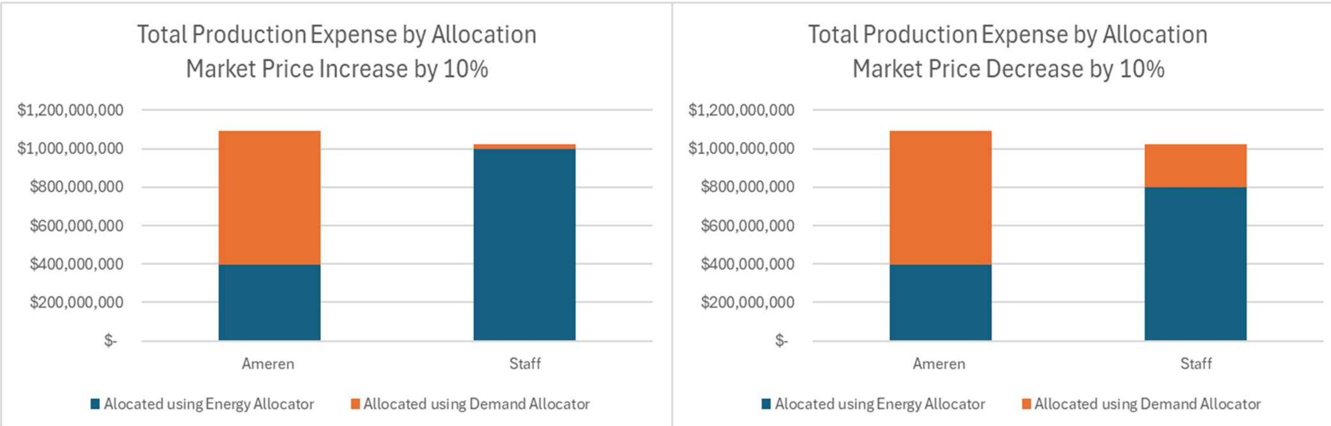
A. The return on rate base is treated slightly differently between Staff and Ameren as is the proposed level of return; in order to keep the number of differences smaller and more easily compare and contrast the treatment of production function costs, I found it more appropriate to isolate the expenses. However, given that Staff is proposing to allocate all costs related to Type 2 resources on an energy basis[19], including the authorized rate of return the gap between the two approaches will likely widen further inclusive of the return component.

Q. Are there any other concerns you have regarding this reallocation?

A. Yes. The reallocation that Staff has incorporated is a function of market prices. Consequently, if market prices increase, even more demand related costs will be reallocated to energy. Consider, as a hypothetical, what would the outcome be if the simulated generator revenues exceeded the total production revenue requirement? In that case, would the entire revenue requirement be allocated on energy even though the plants are still providing capacity and resource adequacy to the system? Or conversely, if market prices were to decrease, would it be reasonable to allocate portions of fuel and purchased power net of off-system sales on demand? Figure 2 below illustrates this by assuming that market prices increase and decrease by 10%. To simplify the figure, the underlying assumption is that the change in market prices is completely balanced out by changes in fuel cost and sales revenue on the cost side such that the cost of service doesn't change.

[19] Of Staff's proposed return on production plant, 32% is attributed to Type 2 resources.

Figure 2



However, given that historically Ameren has been a net seller of energy into the market (and assuming that it continues to be), that Ameren does not incur much natural gas expense, and recognizing that natural gas prices are highly correlated with the wholesale market clearing prices; if gas prices were to rise, Ameren's fuel cost would not change much but off-system sales revenue is likely to increase, thus reducing net energy related costs. In this situation, Staff's proposed method would increase the overall amount of production revenue requirement allocated on energy. This makes no sense. The opposite would be true for a decrease in natural gas prices – that is, fuel expense would not change much but off-system sales revenues would decrease increasing overall energy related costs, yet Staff's proposal would reduce the amount of costs allocated on energy. Again, this is illogical and counter to efficient pricing. Moreover, it subjects each customer class to market price exposure in a completely unwarranted fashion. As I described above, a change in market prices will significantly alter the proportion of embedded and fixed costs that are allocated to each class. That is antithetical to the nature of a vertically integrated utility that develops owned generation in large part to protect customers from the vagaries of market pricing.

Q. Do you have any final comments regarding this approach?

A. Yes. Fundamentally, by implementing this reallocation of costs based on market prices, what Staff is proposing is analogous to an even more extreme version of the Peak and Average ("P&A") approach that the Commission has previously rejected as it double counts the energy component within the demand component of the energy-weighted allocator.[20] The method as proposed by Staff in this case suffers from the same deficiency.

Q. Please explain.

A. Staff's development of its CCOSS captures the allocation of production demand in three places and uses an energy allocation in two of those, but similar to the P&A method, Staff's approach fails to account for the energy (i.e. average demand) of the customer classes when determining the demand allocation factors and thus double counts the energy component. Said another way, within Staff's implementation of its proposed production allocation, a customer class's entire energy load (average demand) is used in the allocation of both Wholesale Energy Cost and Production Type 2 (which itself is illogical given the total energy from Production Type 2 resources only serves approximately 8.6% of total system energy requirements) and the entire class load in the designated demand hours is use to allocate Production Type 1 costs. This further demonstrates the flaws in Staff's proposal.

[20] File No. ER-2010-0036, *Report and Order,* Findings of Fact on Cost of Service and Rate Design at p. 84, Paragraph 11: "…However, what Staff describes as its method's strength is actually its downfall because the Peak and Average demand method double counts the average demand of the customer classes."

Q. If this reallocation issue were to be corrected, would Staff's proposal then be something you could support?

A. At this time, no. As I mentioned earlier, I commend Staff for its attempt to be forward thinking. There will likely come a time during the energy transition that Ameren will need to reconsider the allocators used in its cost of service to ensure they align with the way a system with significant penetrations of renewable and energy limited resources will impose planning and operational constraints on the system, but now is not that time.

Q. Please describe the remainder of Staff's proposed method to allocate production demand related costs.

A. The method that Staff describes in its testimony in essence is a two-step or bifurcated approach to allocated production demand related costs. The first step is sub-functionalizing the production demand revenue requirements into two categories, "Type 1" and "Type 2". The two categories correspond to two different categories of production resources – those with significant variable operating costs and dispatchability are categorized as Type 1 where those resources with little or no variable cost and dispatchability are categorized as Type 2.[21] Next, these sub-functionalized Type 1 and Type 2 production demand related costs are allocated to classes using unique allocators for each asset type.[22,23] The Type 2 costs are allocated using total class energy, the Type 1 resources are allocated using the class contribution to seasonal peak demands, net of Type 2 resource output during the seasonal peak hours.[24] The use of season peak hours for Type

[21] File No. ER-2024-0319, Sarah L. K. Lange Direct Testimony, pp. 15-16.
[22] Id
[23] Prior to the allocation of costs for the Type 1 and Type 2 resources, as I discussed in the previous Q&As, Staff included a netting step where the sub-functionalized production demand revenue requirements were netted against simulated generator revenues and only the net amount was allocated using the Type 1 and Type 2 production demand allocators.
[24] File No. ER-2024-0319, Sarah L.K. Lange Direct Testimony, pp.15-16.

1 resources is directly related to the seasonal resource adequacy in MISO whereas the decision to allocate Type 2 resources on energy is related to statements made by Ameren about customer preferences for clean energy.[25]

Q. Do you have any concerns with this approach?

A. Yes. Though the concern I just discussed regarding the reallocation of costs based on simulated generator revenues is far and away my greatest concern. My primary concern with the Type 1 and Type 2 method is related to the need for a change in methods at all at this point in time. While Ameren has committed to a long-term policy objective to decarbonize, the Company is currently at early stages in the process. In fact, only about 10% of the installed capacity on Ameren's system is currently Type 2. At these levels, the planning and operation of the system hasn't been materially affected by the penetration of the Type 2 resources. Similarly, while MISO is utilizing a seasonal resource adequacy framework with which Ameren must demonstrate compliance, from a review of Ameren's IRP, no compelling evidence exists that each of the four seasons in MISO's construct are equally contributing to the need for Ameren to invest in new plant to meet the requirement, i.e., not all seasons are causing costs from an investment standpoint and therefore the inclusion of all four seasons within the allocation of demand related production costs fails to align cost causation with cost allocation. Furthermore, when more closely examined, the A&E allocator proposed by Ameren captures both energy characteristics, as well as summer and winter excess demands. Consequently, this allocator already captures many of the characteristics that Staff has discussed and incorporated into its proposal but does so in an industry standard and accepted way and does not lead to disparate outcomes between

[25] Id at 14.

customer classes nor does it result in antithetical allocation outcomes due to changes in market prices.

Q. Please summarize your conclusions and recommendations related to Staff's proposed method to allocate production demand related costs.

A. I recommend that the Commission approve rates that utilize the A&E method to allocate production demand related costs, as proposed by Ameren. In turn, the Commission should reject Staff's proposed method to allocate production demand related costs. Staff has not presented compelling evidence that demonstrating that cost causative factors have fundamentally changed necessitating a commensurate change in cost allocation. Further, Staff's attempt to impose the MISO market's buy-all sell-all framework into the allocation of embedded costs is not reflective of the drivers of the embedded cost of the system, and unreasonably and unnecessarily exposes customer classes to market prices as a determinant of their cost of service. Consequently, modifying the method to allocate production demand related cost in this proceeding would lead to unforeseeable and inequitable shifts in revenue apportionment across the customer classes.

Furthermore, parties should not be left guessing as to what steps or approach is used in a CCOSS or why it was used. This is neither efficient nor in the best interest of the Commission to potentially rely on any CCOSS analysis that cannot be fully vetted or understood by other parties or the Commission. I recommend that the Commission require as a matter of procedure going forward, that if parties file alternative CCOSS that are not based on the same CCOSS model filed by the utility initiating the rate review, those parties should be required to file sufficient detail including but not limited to a fully unbundled breakdown of costs at each step (Functionalization, Classification, and Allocation) within the cost allocation process to ensure full understanding and transparency of alternative models by all parties to the case, as well as the Commission.

III. RESPONSES TO RECOMMENDATIONS OFFERED BY CCM RELATED TO THE CLASSIFICATION AND ALLOCATION OF DISTRIBUTION COSTS

Q. Please summarize the positions taken by CCM related to the classification and allocation of distribution costs?

A. CCM takes issues with Company's use of the Minimum Distribution System ("MDS")[26] method for classifying portions of the distribution system as customer related and claims this method does not accurately reflect cost causation.[27] Instead of utilizing the MDS method, CCM recommends the use of the Basic Customer Method ("BCM") to determine the customer related costs.[28]

Q. Before addressing your specific areas of disagreement with CCM, are there any areas of agreement that you would like to highlight?

A. Yes, First and foremost, despite the concerns CCM raises with regard to the classification and allocation of distribution costs, CCM finds the Company's proposed revenue allocation reasonable.[29] As such, it may not be necessary for the Commission to address the specific issues raised by CCM given the agreement on overall revenue apportionment. Secondly, while CCM does raise concerns with the MDS approach, ultimately CCM provides a secondary recommendation that should the Commission continue to set rates that utilize the MDS method, the implementation should be altered to

[26] The Minimum Distribution System method typically takes one of two approaches, the Minimum Size or the Zero Intercept. Ameren uses the Minimum Size approach.
[27] File No. ER-2024-0319, Direct Testimony of Caroline Palmer, p. 3.
[28] Id at 11
[29] File No. ER-2024-0319, Direct Testimony of Caroline Palmer, p. 3.

only consider a customer component on the secondary system.[30] The seems to implicitly validate the reasonableness of some level of customer component for the distribution system above just the BCM.

Q. What specific arguments does CCM raise in its criticisms of the MDS approach?

A. CCM states that while the MDS approach classifies significant portions of distribution costs as customer related, the cost of the equipment in distribution accounts does not vary with the number of customers, but rather demand, which contradicts the National Association of Regulatory Utility Commissioners ("NARUC") Cost Allocation Manual's definition of customer related costs.[31] CCM also contends that new customers do not cause new infrastructure (aside from dedicated customer infrastructure) in populated areas.[32] CCM questions whether the number of customers on the secondary system can materially influence the design and installation of primary system equipment.[33] CCM also asserts the Company's minimum system is outsized relative to the size of the average residential customer.[34] CCM also suggests that the Company's data records via Federal Energy Regulatory Commission ("FERC") minimum system accounts are not detailed enough to properly identified differences equipment that should be excluded from the MDS study.[35] Given the foregoing, CCM recommends that the BCM (as described in the Regulatory Assistance Project's manual Electric Cost Allocation for a New Era), be used

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[30] Id at 13.
[31] Id at 7.
[32] Id.
[33] Is at 8.
[34] Id.
[35] Id at 9

to identify customer related costs and provides examples of five jurisdictions that have adopted the BCM approach.[36]

Q. Please discuss the characteristics of distribution plant as it relates to the classification between demand and customer components.

A. For distribution costs found in Account Nos. 364 (Poles, Towers & Fixtures), 365 (Overhead Conductor), 367 (Underground Conductor), 368 (Line Transformers), 369 (Services), 370 (Meters), and 373 (Street Lighting), either all or a portion of the costs are customer related because they are caused by customers. There is no basis for arguing that Account Nos. 369 – 373 are not customer related. For Account No. 369 – Services, each customer has a service designed to meet that customer's own load characteristics. The service line is dedicated to the customer to meet the load of the customer premise. Services are dedicated to a customer and each customer causes the cost of its service even if the customer never consumes any energy beyond a single light bulb. If the customer is able to avoid all volumetric electric charges and pays only a nominal, non-compensatory customer charge, the result is not just and reasonable and would cause undue discrimination unless that minimum charge covers not only the service line costs but the component of all of the other distribution costs related to providing the customer access to the electric system.

Electricity will not flow into a premise without an electric meter (Account No. 370). For smaller customers, meters are virtually the same for each customer. As customers increase in size, the meter installation becomes increasingly complex and the cost of meter sets increase. In addition to the costs of Account Nos. 369 - 373, a customer cannot be

[36] Id at 11.

connected to the system without and cannot receive service without a minimum level of distribution services provided through the assets in Account Nos. 364 – 368. These accounts support the basic distribution facilities that must be extended to connect new customers to the system. All existing premises were at one time new customers for whom the system must have been extended. Further, the utility must continually replace aging infrastructure to continue to serve these customers regardless of their annual kWh usage or their peak demands, though the peak demands could require replacement with equipment sizes above the minimum size. In the case of these distribution facilities, the minimum size of equipment commonly installed under current policies and procedures represents the costs caused by customers in order to connect the minimum load to the system. The concept of a minimum system ensures that the basic infrastructure costs caused by customers are fairly distributed among all customers, regardless of their individual demands. This helps in achieving equity in cost allocation

Q. Does the NARUC Cost Allocation Manual discuss the MDS method?

A. Yes. The NARUC Cost Allocation Manual discusses the MDS approach in Chapter 6, whereby the manual provides guidance on potential ways to classify and allocate distribution plant costs. Specifically, the manual discusses how distribution plant accounts 364 through 370 involve both demand and customer costs and that the customer component will vary by the number of customers and concludes that "the number of poles, conductors, transformers, services and meters are directly related to the number of customers on the utility's system."[37] The decision on how and to what extent to classify certain distribution

[37] NARUC Cost Allocation Manual at 90.

system costs as customer related costs is left to the analysts and ultimately to the Commission's approval of just and reasonable rates.

Q. Do you agree with CCM that that new customers do not cause new infrastructure (aside from dedicated customer infrastructure) in populated areas?

A. To an extent yes; however, this argument misses a fundamental point of cost causation. At one point in time, all areas were less populated and/or required the initial extension and build out of electrical infrastructure and in order to provide for the ability to serve expanding areas (i.e. new geographies), new infrastructure was necessary. This is what caused the customer related costs to be incurred. Just because a customer moves out and a new customer is able to take service at an existing location or in areas that have already had the necessary customer related infrastructure put into place, does not reclassify those customer related costs as demand related costs. One must look back to what caused those costs to be incurred in the first place.

Q. Are there reasons why the minimum size of equipment exceeds the size of individual customers?

A. Yes. The minimum size of utility equipment is not only a function of the size of the smallest customers, but also must consider safety codes and standards, the size of commonly made equipment (which can lead to easier replacements in case of failures, lower costs for standard equipment, some economies of scale, etc.) and other factors that go into electrical design. A specific example raised by CCM is the minimum transformer size of 25 kVA used by Ameren and how this exceeds the average size of ~6 kW for a residential customer.[38] 25kVA is a common transformer size and the use of smaller

[38] File No. ER-2024-0319, Direct Testimony Caroline Palmer, p.8.

transformers is not common practice in the industry. This size of transformer becomes less expensive per unit than purchasing multiple smaller transformers (if they are available), allows for growth, allows for easier replacement from common inventory if a unit fails leading to quicker responses to outages, etc. Using a minimum system tailored to the smallest possible size customer (or tailored to individual customer sizes) would inevitably increase the overall cost to serve, limit the potential for growth and timely interconnection, and potentially make the system less safe and less reliable.

Q. CCM also discusses limitation in data causing problems with the MDS analysis, do you have any thoughts on this?

A. Yes. While data may not be perfect, the data has been of enough quality to rely upon for rate making purposes for years. One should not put themselves into the position of waiting for perfection as new data can be continually evaluated and used to improve the process. However, similar to a statement I made early regarding the production allocation proposal from Staff, there has not been a change in the planning or operations of the distribution system, or even the data that warrant a significant departure from accepted practice. In order to achieve a level of predictability in rates and fairness among customer classes, deference should be given to precedent when there is a lack of compelling evidence demonstrating that cost causative factors have fundamentally changed this necessitating a commensurate change in cost allocation. CCM has not presented compelling evidence to the affect.

Q. CCM argues that the number of secondary customers is not a determinative factor in the design of the primary system, do you agree?

A. No, at least not outright. There can be instances where the number of secondary customers can cause design differences on the primary system and there are other instances where it would not. One must carefully review the engineering design of the system to make this determination. CCM has not presented evidence to demonstrate that its hypothetical is actually applicable to Ameren's system.

Q. Rather than continue the use of the MDS method, CCM recommends the use of the BCM as described in the Regulatory Assistance Project's ("RAP") manual Electric Cost Allocation for a New Era. Are you familiar with the RAP organization?

A. Yes. RAP markets itself as an independent, global, non-governmental organization advancing policy innovation and thought leadership within the energy community. Published in 2020, RAP's Electric Cost Allocation for a New Era Manual is a comprehensive reference source covering all elements of cost allocation for electric utilities. However, the "Manual" was not peer reviewed and it reflects the inherent biases of its authors and the financiers of RAP. Our firm reviewed the publication at some length as part of a client engagement where it was appended to testimony in a regulatory proceeding. Atrium researched publicly available information listed in Table 1 to discern those who back RAP.[39]

[39] The data in Foundation Directory Online is compiled from IRS information returns (Forms 990 and 990-PF), grant-maker web sites, annual reports, printed application guidelines, the philanthropic press, and various other sources. https://fconline.foundationcenter.org/

Table 1

Regulatory Assistance Project Grantmakers - Total Grants (2016-2020)

Regulatory Assistance Project Grantmakers	Grand Total
The William and Flora Hewlett Foundation	$ 8,600,000
Energy Foundation China	6,782,000
Sea Change Foundation	2,000,000
Climate Works Foundation	1,275,000
Barr Foundation	675,000
The John Merck Fund	400,000
Robertson Foundation	375,000
The Heising-Simons Foundation	350,000
McKnight Foundation	275,000
Walton Family Foundation	250,000

Based on our review, there is a consistent public policy position and goal of the financiers of this organization to support the expansion and adoption of clean energy and public policy that encourages distributed generation adoption.[40] One way to encourage distributed generation is to design rates that reduce fixed charges and increase volumetric charges such as reducing the customer classification. However, given the necessary strengthening of the distribution grid to support distributed generation and other policy initiatives such as electrification (which may affect the minimum distribution equipment), to ensure costs are recovered equitably, distribution costs included in included in fixed charges should increase, not decrease.

Q. CCM also presents a list of five Commissions that either have explicitly rejected the MDS method or otherwise required that utilities classify primary and

[40] A review of the grantmakers websites and mission statements clearly demonstrate their public policy interests: https://hewlett.org/about-the-environment-programs-grantmaking-2 | https://www.efchina.org/Front-Page-en | https://www.seachange.org/ | https://www.climateworks.org/ | https://www.barrfoundation.org/climate | https://www.jmfund.org/program-areas/clean-energy/ | https://robertsonfoundation.org/index.html | https://www.hsfoundation.org/programs/climateclean-energy/ | https://www.mcknight.org/programs/midwest-climate-energy/our-approach/ | https://www.waltonfamilyfoundation.org/

secondary distribution costs as 100 percent demand-related. How many utilities/Commissions are you aware of that utilize the MDS method to classify a portion of the distribution system as customer related?

A. Based on our current experience with client engagements in multiple state jurisdictions and research, electric utilities in at least twenty-six states have adopted to varying degrees a customer component of the distribution system. Some specific examples (excluding Ameren), are presented in Table 2 below.

Table 2

State	Electric Utility	Customer Component of Distribution		Docket/Case Number	Year
		Recognized	Method		
AZ	Tucson Electric Power Co.	Yes	Minimum System	D-E-01933A-15-0322	2015
CT	The CT Light & Power Co	Yes	Minimum System	D-17-10-46	2017
DE	Delmarva	Yes	Minimum System	13-115	2013
FL	Tampa Electric Company	Yes	Min.Distribution System	20210034-EI	2022
GA	Georgia Power Co.	Yes	Minimum System	D-42516	2019
HI	Hawaii Electric Light Co	Yes	Minimum System	D-2018-0368	2018
ID	Idaho Power Company	Yes	Unspecified	IPC-E-11-08	2011
IN	Northern Indiana Public Service Co.	Yes	Minimum System	Cause 45772	2022
KS	Evergy Kansas Central Inc.	Yes	Minimum System	D-18-WSEE-328-RTS	2018
ME	Central Maine Power Co.	Yes	Minimum System	D-2018-00194	2018
MN	Minnesota Power Entrprs Inc.	Yes	Minimum System	D-E-015/GR-16-664	2016
MO	Evergy Missouri Metro	Yes	Minimum System	C-ER-2022-0129	2022
MS	Mississippi Power Co.	Yes	Zero Intercept	2019-UN-0219	2019
MT	MDU Resources Group, Inc.	Yes	Minimum System	2022.11.099	2022
NC	Duke Energy Carolinas, LLC	Yes	Minimum System	E-7, Sub 1214	2019
ND	Northern States Power Co.	Yes	Both	C-PU-20-441	2020
NH	Unitil Energy Systems Inc.	Yes	Minimum System	D-DE-16-384	2016
NM	Public Service Co. of New Mexico	Yes*	Zero Intercept	16-00276-UT	2016
NY	Consolidated Edison Co. of NY	Yes	Minimum System	C-16-E-0060	2016
OH	Duke Energy Ohio	Yes	Minimum System	21-887-EL-AIR	2022
OK	Oklahoma Gas and Electric Co.	Yes	Zero Intercept	Ca-PUD201500273	2015
PA	PPL Electric Utilities Corp.	Yes	Minimum System	D-R-2015-2469275	2015
SC	Duke Energy Progress LLC	Yes	Minimum System	D-2018-318-E	2018
SD	Xcel Energy	Yes	Minimum System	EL14-058	2014
VA	Virginia Electric and Power Co.	Yes	Unspecified	C-PUE-2009-00019	2009
WI	Wisconsin Electric Power Co.**	Yes	Minimum System	D-05-UR-107	2014

*The use of minimum system was approved by the NMPRC, PNM indicated in testimony that it prferred a zero intercept approach over minimum distribution system but has yet to implment in rates

** Testimony indicates that the MSS is used both in WI and MI service territories

1. Ameren Missouri has been excluded from this list

Q. Please summarize your conclusions and recommendations related to CCM's positions regarding the classification and allocation of distribution costs.

A. I recommend that the Commission approve rates that utilize the MDS method to classify and allocate distribution costs and reject CCM's proposal to adopt the BCM. I further recommend that the Commission reject CCM's alternative proposal to utilize a MDS with no primary customer component as this would not align with cost causation on Ameren's System.

IV. RESPONSES TO RECOMMENDATIONS OFFERED BY STAFF RELATED TO THE CLASSIFICATION AND ALLOCATION OF DISTRIBUTION COSTS

Q. Please summarize your concerns with Staff's approach to the classification and allocation of distribution costs.

A. Before I discuss my concerns, it should be noted that Ameren witness Hickman is providing responses to many of the specific issues related to Staff's classification and allocation of distribution costs. I am providing a higher-level perspective and consequently I will not respond to every concern found within Staff's approach to distribution cost classification and allocation.

That said, the primary concerns I have with Staff's approach is the misuse of data and related issues in the development of its classification and allocation of distribution costs, including the improper application of direct assignment of certain costs to customers/customer classes. Specifically, Staff has significantly increased the direct assignment of costs to classes rather than rely on system averages, ratios, etc. typically used in CCOSS and ratemaking. However, in doing so Staff has failed to properly adjust the remainder of the CCOSS to account for the direct assignments. This is a fundamental flaw which in essence causes an overallocation of system costs and thus subjects customer classes that receive direct assignments of costs to higher cost of service than is fair or reasonable.

Q. What is the proper way to incorporate the direct assignment of costs within a cost-of-service study?

A. If costs are to be directly assigned to a specific customer or class of customers, an adjustment must be made to the billing determinants used for the allocation of the rest of the system costs to reflect the exclusive use of part of the system by only one customer or class of customers. Staff has failed to adjust the CCOSS in that way leading to customers/customer classes who are directly assigned portions of the system to not only pay the direct assigned costs but also pay for a full share of allocated system costs rather than a share net of the requirements served by the directly assigned portions of the system.

Q. When including directly assigned costs in cost allocation, what is typically the outcome?

A. The request to directly assign costs for parts of the system are usually brought forth by larger customers on the system. Typically, when going through the process assigning specific portions of the system to larger customers and properly accounting for the effects throughout the determination of billing determinants input into the allocated CCOSS, the resulting outcome is less revenue responsibility attributed to larger customers. This is understandable and attributed to two main reasons: (1) larger equipment sizes tend to have a lower unit cost than smaller equipment so, for example, it is better economically for a larger customer to directly pay for the cost of a single large transformer rather than an equivalent kW share of many smaller transformers; and (2) larger customers do not use as much of the system as smaller customers and typically large portions of the higher voltage equipment has been in-service for many years leading to a lower net plant value.

Q. Can you point to example from other utilities to demonstrate this?

A. Yes. A prime example is Duke Indiana's HLF tariff.[41] This tariff provides separate demand and energy charges for Transmission customers at or above 138 kV, Transmission customers at 69 kV, Primary Direct Service (direct assigned), Primary Service (not direct assigned), and Secondary Service. Table 3 below summarizes the demand and energy charges as well as presents the effective all-in rate per kWh for each service option demonstrating the outcome I discussed in the previous response. It is worth noting that Duke Indiana went through years of painstaking effort to get the accounting data organized and recorded in a way to support this tariff. In addition, it is not something that is easily available nor something that most utilities undertake given the level of effort and typically small but detrimental effect on smaller customers, when most frequently the proper application of a minimum system study alone is able to fairly classify and allocate distribution costs.

[41] Duke Indiana Rate HLF

Table 3

Duke Indiana HLF Tariff Rates				
Customer		Customer Charge ($/Month)	Demand Rate ($/kW-Mo)	Energy Rate ($/kWh)
Transmission (138 kV+)		$ 658.07	$ 16.22	$ 0.042678
Transmission (69 kV)		$ 658.07	$ 17.21	$ 0.042158
Primary Direct		$ 96.64	$ 17.85	$ 0.043354
Primary		$ 96.64	$ 14.26	$ 0.055107
Secondary		$ 24.54	$ 20.08	$ 0.048127
Hypothetical Customer Analysis				
Customer	Load Factor	kW	kWh	All-In Cost ($/kWh)
Transmission (138 kV+)	75%	50,000	27,375,000	$ 0.072328
Transmission (69 kV)	75%	50,000	27,375,000	$ 0.073616
Primary Direct	75%	1,000	547,500	$ 0.076133
Primary	75%	1,000	547,500	$ 0.081329
Secondary	75%	30	16,425	$ 0.086297

*all customers assumed to have a load factor of 75% given this is a high load factor tariff.
** kVAr charge of $0.28 / kVAr has been omitted

Q. Are there examples of the same holding true for Ameren once Staff's error regarding the billing determinants is corrected?

A. Yes. This is discussed on pages 5-7 of the Rebuttal Testimony of Ameren witness Hickman.

Q. Do you agree with Staff's approach to incorporate more data and use this to refine the allocation of distribution costs?

A. Setting aside my concern regarding correcting of Staff's approach to reflect a proper implementation, while I understand where Staff is coming from, this is not a common approach in the industry, though there are examples such as Duke Indiana, where the approach is used. I would always recommend it is best practice to understand what data is available, what will become available and what changes in record keeping can be practically and cost-effectively accommodated to refine analytical approaches. However, care should be taken to move forward in measured ways rather than all at once to ensure that the additional data collection and complexity is worth the cost and effort relative to the potential increase in precision that its use may provide. No data is perfect, and it can take years to prepare a new dataset for reliable use. Ultimately, ratemaking is about determining just, reasonable, and non-discriminatory rates for classes of customers and the level of precision is limited due to the use of class level data, ratios, averages, etc. Said another way, there is no such thing as a perfect CCOSS or rate design, rather the goal is a principled, well-reasoned CCOSS and rate design for all customers.

Q. Please summarize your conclusions and recommendations regarding classification and allocation of distribution costs.

A. I recommend that Staff's proposed modifications to the classification and allocation of distribution system costs also be rejected. Staff's proposal is fundamentally flawed and cannot be relied upon for setting just and reasonable rates.

Q. Does this conclude your testimony?

A. Yes, I have nothing further at this time.

Nicholas L. Phillips

DIRECTOR

Mr. Phillips is a seasoned professional in the energy and utility sector, with extensive expertise spanning utility system planning, forecasting, unit costs, power plant operations, costing, ratemaking, and regulatory activities. He has testified in approximately 50 different regulatory proceedings on a wide range of issues for clients across North America, including (but not limited to) utility resource planning, resource adequacy and resiliency, resource retirement and acquisitions, class cost of service and rate design, allocation methods, load forecasting, revenue requirements, production cost analysis, fuel and purchased power costs, off-system sales margins, retail open access, exit fees, market design, avoided cost analysis, renewable portfolio standards, and energy efficiency. His proficiency extends across virtually all aspects of electric and gas issues and has worked on behalf of his clients to evaluate complex issues during a time of transition for utilities and energy users alike.

Prior to joining Atrium as a Director, his previous career includes roles include Director of Integrated Resource Planning at Public Service Company of New Mexico (PNM), where he managed planning and regulatory support, and as a Principal at Brubaker & Associates, Inc. (BAI), where he represented electricity and natural gas customers, testifying before regulatory bodies on utility-related issues.

Mr. Phillips' academic achievements include a Master of Science degree in Computational Finance and Risk Management from the University of Washington - Seattle, a Master of Engineering degree in Electrical Engineering from Iowa State University of Science and Technology, and Bachelor of Science degrees in Electrical Engineering and Criminology and Criminal Justice from the University of Missouri - St. Louis.

EDUCATION

M.S., Computational Finance and Risk Management, University of Washington - Seattle

M.Eng., Electrical Engineering, Iowa State University

B.S., Electrical Engineering, University of Missouri – St. Louis

YEARS EXPERIENCE

15

RELEVANT EXPERTISE

Utility Resource Planning, Costing and Pricing, Expert Witness Testimony, Revenue Requirements, Class Cost of Service, Rate Design, Statistics, Valuation, Market Studies, Rate & Regulatory Case Management, Resource Adequacy, Load Normalization and Forecasting, Strategic Business Planning.

EXPERT WITNESS TESTIMONY PRESENTATION

UNITED STATES

California Public Utilities Commission

Idaho Public Utilities Commission

Kansas Corporation Commission

Michigan Public Service Commission

Missouri Public Service Commission

New Mexico Public Regulation Commission

Public Utilities Commission of Nevada

Public Service Commission of Wisconsin

Wyoming Public Service Commission

Federal Energy Regulatory Commission

REPRESENTATIVE EXPERIENCE

RESOURCE PLANNING

Mr. Phillips has worked on numerous resource planning projects related to utility resource planning, procurement, and asset retirement issues. Specifically, he has:

- Developed two Integrated Resource Plans (2020 & 2023) for Public Service Company of New Mexico.
- Developed resource planning analysis (economic and resource adequacy) in support for the abandonment/exit from two coal plants, as well as in support of multiple gas, renewable and storage assets.
- Worked with software vendors and internal stakeholders to improve cross functional planning process between generation and transmission.
- Reviewed resource planning analysis developed by utilities to ensure the proposed assets (gas and renewable resources) were the lowest reasonable cost alternatives.
- Review utility IRP’s and prepares fundamental based resource planning analysis to forecast utility cost of service.

RATE DESIGN AND REGULATORY PROCEEDINGS

Mr. Phillips has worked on numerous rate cases helping to prepare and review revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America (both embedded and marginal cost studies) and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Work in conjunction with the utility pricing group to develop and propose a new class cost of service allocation method for systems with significant renewable penetration.
- Review WNA/RNA mechanisms for a utility including back casting results.
- Supported the development of time of use rates, demand rates, economic development rates, and load retention rates.
- Supported lead-lag analyses.
- Prepared load forecasts and analyzed customer usage profiles used for planning and ratemaking.
- Developed exit fee calculations in support of customers seeking to access electric supply form an alternative supplier.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Mr. Phillips has testified in several cases on resource planning, class cost of service studies and numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on new resource acquisitions and resource requirements and integrated resource plans.
- Filed testimony as an expert witness on allocated class cost of service studies (both embedded and marginal cost studies).
- Filed testimony as an expert witness discussing potential changes necessary to align cost allocation with cost causation as utilities decarbonize their systems.
- Filed testimony as an expert witness on the application of statistical analysis.
- Filed testimony as an expert witness on the application of retail open access and the proper exit fees / protection necessary to balance the interests of the utility, retail customers and the applicant seeking alternative retail supply.
- Filed testimony as an expert on utility avoided costs, energy efficiency and renewable portfolio standard compliance.
- Filed testimony as an expert on production cost simulation estimates for fuel and purchase power costs and methods for estimated off-system sales margins.

SPEAKING EXPERIENCE

- Wholesale Electric Power Markets and Transmission, BAI Annual Seminar: Utility Ratemaking Fundamentals, St. Louis MO, 2013
- Power Markets and Natural Gas Markets, BAI Annual Seminar: Utility Ratemaking Fundamentals, St. Louis MO, 2013 & 2014
- Energy Market Economics, BAI Annual Seminar: Utility Ratemaking Fundamentals, St. Louis MO, 2015 & 2016
- PNM 2020 IRP Public Advisory Meetings, Multiple Topics/Multiple Meetings, Albuquerque NM, 2019 - 2021 https://www.pnmforwardtogether.com/presentations
- PNMR Board of Directors, October 2020, Resource Adequacy in deep carbonization
- Rocky Mountain Mineral Law Foundation, March 2021, Benefits and Concerns Integrating Energy Storage on Utility Systems
- Sandia National Labs, March 2021, New Mexico Energy Transition Act
- Numerous Internal Presentation to PNM Departments
- Community Solar Working Group, October 2020, Integrating Solar on PNM's System
- EPRI, February 2021, Hybrid Solar-Storage
- EUCI, October 2020, Properly Reflecting Coal Plant Retirements in IRP
- EUCI, May 2021, Resource Adequacy Planning in IRP
- Iowa State, April 2020, Integrated Resource Planning
- EUCI, February 2022, De-carbonization: Modeling Options and Limitations in IRP
- New Mexico Governors Economic Development Forum, September 2022, Clean Energy Impact on Economic Development Opportunities
- SolarPACES, September 2022, Concentrating Solar Power in the Energy Transition
- Nextera Energy Storage in the West, October 2022, Utility Perspective of Storage Operations in Bilateral Markets
- DOE Energy Storage Conference, October 2022, Utility Perspective on the Grid of the Future
- Sandia Nation Labs, October 2022, How to Accelerate the Energy Transition in New Mexico
- New Mexico Renewable Transmission Authority, October 2022, The Role of Storage in Utility Reliability
- National Black Caucus of State legislators, November 2022, Grid Resiliency and Reliability Considerations in a Renewable Grid
- Leadership Sandoval, February 2023, New Mexico's Energy Transition
- Water and Energy Conversation Coalition, March 2023, Challenges in Decarbonization.

- EUCI, April 2023, Integrated Resource Panning – Resource Adequacy Planning in a Heavy Renewable Energy / Deeply Decarbonized Grid

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF NICHOLAS L. PHILLIPS

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

Nicholas L. Phillips, being first duly sworn states:

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

____
Nicholas L. Phillips

Sworn to me this 17 day of January, 2025.