Exhibit No.:
Issues: Cost of Service/Revenue Allocation/Rate Design
Witness: Jessica A. York
Type of Exhibit: Rebuttal Testimony
Sponsoring Party: Missouri Industrial Energy Consumers
Case No.: ER-2024-0319
Date Testimony Prepared: January 17, 2025

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**

Rebuttal Testimony of

Jessica A. York

On behalf of

Missouri Industrial Energy Consumers

January 17, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11700

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**

STATE OF MISSOURI)
) **SS**
COUNTY OF ST. LOUIS)

Affidavit of Jessica A. York

Jessica A. York, being first duly sworn, on his oath states:

1. My name is Jessica A. York. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Missouri Industrial Energy Consumers in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my rebuttal testimony which was prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2024-0319.

3. I hereby swear and affirm that the testimony is true and correct and that it shows the matters and things that it purports to show.

Jessica A. York

Subscribed and sworn to before me this 17th day of January, 2025.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 18, 2027
Commission # 15024862

Notary Public

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**

Table of Contents to the Rebuttal Testimony of Jessica A. York

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**

Rebuttal Testimony of Jessica A. York

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jessica A. York. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME JESSICA A. YORK WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING ON DECEMBER 17, 2024?

A Yes, I am.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers ("MIEC"), a non-profit corporation that represents the interests of large consumers in Missouri rate matters.

I. INTRODUCTION AND SUMMARY

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A The purpose of my rebuttal testimony is to respond to the class cost of service study ("CCOSS") recommendations made in the Direct Testimony of Consumers Council of Missouri's ("CCM") witness Caroline Palmer, and Missouri Public Service Commission

("MOPSC" or "Commission") Staff's witness Sarah Lange. Specifically, I will address Ms. Palmer's recommendation to use the Basic Customer method for classifying and allocating distribution costs, and I will address Ms. Lange's recommendations regarding the allocation of Ameren Missouri's ("AMO" or "Company") production and distribution capacity costs as well as her recommended allocation of Administrative and Overhead ("A&O") costs.

My silence regarding any position taken by any other party in their Direct Testimony or other filings in this proceeding does not indicate my tacit endorsement of that position.

Q PLEASE PROVIDE A HIGH LEVEL SUMMARY OF YOUR FINDINGS AND RECOMMENDATIONS.

A I find that the use of the Basic Customer method for classifying distribution costs does not accurately reflect cost causation and should be rejected.

In addition, I find that Staff has proposed allocations of production, distribution, and A&O costs among customer classes that are not based on generally accepted cost allocation principles, and that would seriously over-allocate costs to large, high load factor customers, particularly those who take service under the Large Primary Service ("LPS") rate. Many of Staff's allocation methods are based on unsupported assumptions and data that Staff itself characterizes as anomalous and/or lacking sufficient detail.

Staff's recommendations on the allocation of any revenue change based on Staff's flawed cost allocations are therefore flawed and should be rejected. Instead, Ameren Missouri's cost of service study should be used to define class revenue

requirements under conventional approaches and should be the basis for determining an appropriate allocation of any change in revenues across customer classes.

II. RESPONSE TO CCM WITNESS MS. PALMER

Q PLEASE SUMMARIZE THE ISSUES IN MS. PALMER'S DIRECT TESTIMONY TO WHICH YOU WILL RESPOND.

A Ms. Palmer concludes that the Company's CCOSS model relies on what she believes to be a flawed minimum system study because it classifies distribution costs, recorded in Accounts 364-368, as both demand and customer.[1] Ms. Palmer asserts these costs should be classified as only demand.[2]

Q DO YOU BELIEVE THAT MS. PALMER'S CRITICISMS OF THE COMPANY'S MINIMUM DISTRIBUTION SYSTEM METHOD ARE REASONABLE?

A No. Ms. Palmer's proposed use of the Basic Customer Approach for classifying distribution system costs fails to properly classify and allocate distribution costs across rate classes based on customer and demand cost-causation principles. She believes that distribution costs are primarily demand-related, and that the Company has overallocated distribution costs to the Residential class.[3] Further, while Ms. Palmer states that she modified the Company's CCOSS to measure the impact of her cost allocation proposal on each customer class, she acknowledges that the result is based on her best efforts to modify the CCOSS by adjusting the distribution classification factors.[4] She further explains that she could not comprehensively modify the

[1] Direct Testimony of Caroline Palmer at page 5, lines 8-10.
[2] *Id.* at page 11.
[3] *Id.* at page 10, lines 5-13.
[4] *Id.* at page 12, lines 12-13.

Company's CCOSS due to what she characterizes as obstructions in the model.[5] Hence, the extent of the change to the cost of service results based on her position is not known.

Q WOULD THE COMPANY BE ABLE TO ACCURATELY ESTIMATE ITS COST OF SERVICE ACROSS RATE CLASSES WITHOUT CLASSIFYING ITS DISTRIBUTION SYSTEM AS INCLUDING BOTH CUSTOMER AND DEMAND COMPONENTS?

A No. Distribution costs are incurred to meet the utility company's customer demands and the distribution costs are also incurred to connect customers to the system. As such, distribution costs are caused by both customer demands and number of customers on the system.

The Company's minimum system approach is consistent with practices in the industry and is reasonable for determining the amount of distribution costs that should be classified as customer related and, in part, allocated across customer classes based on number of customers.

Q IN TOTAL, WHAT PORTION OF DISTRIBUTION PLANT IN ACCOUNTS 364-368 DID THE COMPANY CLASSIFY AS CUSTOMER-RELATED?

A The Company classified about 48% of distribution costs in those accounts as customer-related.[6] This means the Company has classified the majority (52%) of these costs as demand-related.

[5] *Id.* at lines 13-17.
[6] AMO's workpaper "MO ECCOS_2024 Final" tab "Cost."

Q MS. PALMER REFERENCES THE REGULATORY ASSISTANCE PROJECT'S ("RAP") MANUAL *ELECTRIC COST ALLOCATION FOR A NEW ERA* IN SUPPORT OF THE BASIC CUSTOMER METHOD. DO YOU HAVE ANY COMMENTS ON THE RAP MANUAL?

A Yes. The RAP manual is biased. It carries neither the history of use, nor the objectivity of the NARUC Manual, which it seeks to rebut in certain instances. The NARUC Manual, which was authored by public service commission staff, is objective, time-tested and has been the quintessential guide for cost allocation for decades. In contrast, the RAP manual generally sets forth the traditional positions and arguments that small consumer advocates typically make in state regulatory proceedings with respect to the allocation of electricity costs.[7] Even to the extent a different approach of allocating costs is needed for a "new era," and I'm not stating that it is, then perhaps that new allocation method should be applied only to new distribution facilities, and only to the extent they are constructed for reasons dissimilar to utility construction of distribution assets historically.

Q PLEASE EXPLAIN WHY DISTRIBUTION COSTS ARE DRIVEN BY BOTH DEMAND AND NUMBER OF CUSTOMERS.

A Distribution costs reflect circuits that are stepped down below subtransmission voltage to primary and secondary voltage in order to provide service to customers. An analogy can help illustrate why these circuit costs are driven by both customer demands and number of customers.

[7] Indeed, the authors of the RAP manual have been small consumer advocates and testified on residential allocations and rate designs in various jurisdictions over the years.

For example, consider two customer distribution circuits. One distribution circuit (Circuit A) has ten customers on it with a peak demand of 110 kW. A second distribution circuit (Circuit B) services five customers also with peak demand of 110 kW.

Circuit A has five miles of conductor cable and related poles, and five pole transformers that step down the primary distribution service to secondary voltage because the line transformers provide service to more than one customer. In contrast, Circuit B customers are dispersed further apart and has 10 miles of conductors, related poles, and five pole transformers because the customer locations do not allow serving more than one customer from a pole transformer due to the distance between customer service drops.

In both of these examples, the primary system and secondary distribution loop can serve all these customers' demand using the Company's minimum size distribution equipment capable of serving 110 kW demand. However, the distribution costs incurred for Circuit A would be lower than the distribution cost incurred for Circuit B because of the configuration of the distribution system, and the equipment needed to connect customers to the system. Hence, the distribution costs in this example are impacted by both: (1) the location of the customers; and (2) the customer demand on the circuits. A minimum facilities study is needed to estimate the distribution cost that must be incurred to connect customers to the system but is not based on circuit demand.

In this example, while both distribution loops carry the same 110 kW demand, Circuit A will be less expensive than Circuit B because of the greater cost incurred to connect the Circuit B customers to the distribution system. In this instance, the

distribution system cost would be incurred both based on the peak customer demands on the circuit and the cost incurred to connect the customers to the distribution system.

As such, in allocating these costs, the Commission should carefully consider both the distribution costs incurred to serve customers' demand, and the costs incurred to connect customers to the system. For these reasons, the Company's use of the customer classification in allocating distribution costs based on its minimum system is a widely used and generally accepted cost of service methodology and should continue to be used in the CCOSS. CCM's proposed method is flawed, not generally accepted, and should be rejected.

III. RESPONSE TO STAFF WITNESS MS. LANGE

Q DO YOU HAVE ANY GENERAL OBSERVATIONS REGARDING STAFF'S RECOMMENDED CCOSS?

A Yes. Staff proposes drastically different allocation methods than the Company for production, distribution, and A&O costs. However, Staff has not explained in its direct testimony why it is necessary or reasonable to abandon the Company's long-standing cost allocation methods in this case. Further, Staff's model is very data intensive, and incorporates unsupported assumptions. It would be inappropriate to adopt Staff's recommended CCOSS and revenue allocation proposals.

Staff's Allocation of Production Costs

Q HOW DOES STAFF FUNCTIONALIZE AND ALLOCATE PRODUCTION COSTS FOR COMPANY-OWNED RESOURCES?

A Staff designates Company-owned generation resources as either Type 1 or Type 2. Type 1 resources are defined as those that have significant variable costs of operation

which are avoidable if the unit is offline and are fully dispatchable with limited exceptions.[8] Staff defines Type 2 resources as having little or no variable costs with the dispatch often limited by weather conditions or other factors beyond the control of the utility.[9]

Q HOW DID STAFF ALLOCATE COSTS ASSOCIATED WITH TYPE 1 RESOURCES?

A Staff allocates the cost of Type 1 resources based on customer class loads during certain identified hours.[10] Staff refers to the "All Peak Hours Approach" described in the 1992 NARUC Electric Utility Cost Allocation Manual ("Manual") and uses class loads during the four peaks consistent with the four Midcontinent Independent System Operator ("MISO") resource adequacy seasons, offset by the class's allocation of hourly generation of production Type 2 resources.[11] In other words, Staff identified each class's Four Coincident Peak ("4CP") demand, and then removed an allocated share of the generation provided by Type 2 resources from each class's 4CP demand (where the allocated share of Type 2 energy generation is based on an energy share).[12]

Q HOW DOES STAFF ALLOCATE THE REVENUE REQUIREMENTS ASSOCIATED WITH TYPE 2 FACILITIES?

A Staff states that a "Partial Energy Weighting" method was used.[13] Staff states that this approach allocates the Type 2 production plant costs on the basis of energy loads but

[8] Direct Testimony of Sarah Lange at page 15, lines 2-4.
[9] *Id.* at lines 4-7.
[10] *Id.* at lines 8-10, and page 16, lines 1-2.
[11] *Id.*
[12] Staff's "CCOS Inputs" workpaper.
[13] Direct Testimony of Sarah Lange at page 16, lines 3-4.

does not classify the costs as "energy-related," in that these costs are not expected to vary with the level of generation produced or consumed.[14]

Q HOW HAS STAFF ALLOCATED THE COSTS OF PURCHASES AND SALES?

A Staff's testimony indicates that its CCOSS allocates the market cost of energy based on each class's hourly load and the hourly MISO Day Ahead Locational Marginal Prices from July 2023 through June 2024.[15]

Q IS IT ACCURATE TO SAY THAT STAFF HAS APPLIED DIFFERENT ALLOCATION METHODS AND ASSUMPTIONS TO DIFFERENT KINDS OF PRODUCTION RESOURCES.

A Yes. Staff has applied different allocations to Type 1 resources, Type 2 resources and to the whole cost of energy, as described above.

Q IS IT REASONABLE TO BIFURCATE THE COMPANY-OWNED PRODUCTION RESOURCES BETWEEN TYPE 1 AND TYPE 2?

A No. Staff's approach, which attempts to allocate different resources in different ways, is not only complicated, but unnecessary. It also ignores the fact that particular resources are not built for particular customer classes or segments of load, but rather that each utility constructs a portfolio consisting of various kinds of resources that have been acquired with the objective of meeting customer requirements reliably and in a reasonable least cost manner.

[14] *Id.* at 4-7.

[15] *Id.* at page 13, lines 11-14 and shown in Staff's "529 Wholesale Energy Class Loads" workpaper.

Q HAS STAFF EXPLAINED WHY IT BELIEVES A CHANGE FROM THE COMPANY'S RECOMMENDED PRODUCTION CAPACITY ALLOCATION METHOD IS NECESSARY OR REASONABLE?

A No.

Q HAS STAFF PROVIDED ANY EVIDENCE TO SUGGEST THAT THE WAY AMEREN MISSOURI INCURS PRODUCTION CAPACITY COSTS HAS CHANGED?

A No.

Q HOW DO THE FOUR SYSTEM PEAKS USED IN STAFF'S PRODUCTION CAPACITY ALLOCATOR COMPARE TO THE FOUR SYSTEM PEAKS USED IN THE COMPANY'S ALLOCATOR?

A Staff's Type 1 and Type 2 production capacity allocators reflect the system peak hour that occurred in January, May, June, and September of the test year. Rather than reflecting data from the peak hour in each of the MISO Resource Adequacy seasons, the Company's production capacity allocator reflects the demand data from the actual months when its own system peaked – namely, January, June, July, and August.

Q DOES THE MISO SEASONAL RESOURCE ADEQUACY CONSTRUCT NECESSITATE A CHANGE FROM THE COMPANY'S PROPOSED PRODUCTION CAPACITY ALLOCATION?

A No. As shown in Mr. Brubaker's direct testimony at Figure 4, while AMO did experience a winter peak in its test year, the summer season demands on Ameren Missouri's system are still substantially higher than demands in other time frames. Generally speaking, having capacity sufficient to meet the summer peak loads has historically

been sufficient to meet loads in other seasons.[16] In addition, as described in the Company's 2023 Integrated Resource Plan ("IRP"), AMO plans sufficient resource capacity to meet its customers' highest peak demand, generally on the hottest day of the year for summer and the coldest day of the year for winter, plus a reserve margin to account for uncertainty.[17] The Company's IRP does not indicate that its production capacity costs are driven by spring and fall peak demands.

Q IS STAFF'S APPROACH CONSISTENT WITH GENERALLY ACCEPTED COST ALLOCATION APPROACHES FOR ELECTRIC UTILITIES?

A No. Trying to allocate different resources using different allocation approaches is not consistent with generally accepted practices. Typically, generation and purchased power resources are categorized into fixed costs and variable costs. The variable costs are allocated based on class energy consumption, and the fixed costs are allocated on some measure of demand responsibility, such as the Average and Excess, Four Non-Coincident Peak Method ("A&E-4NCP"). Staff's approach is highly unusual and should be rejected.

Q IN YOUR OPINION, IS THE A&E-4NCP STILL A REASONABLE ALLOCATION TO USE FOR AMEREN MISSOURI?

A Yes. This approach includes both demand and energy components and captures the system peak demands that drive the Company's investment in production capacity.

[16] Based on a review of system peak demands in prior cases, and information in prior IRPs. IRPs prior to 2023 have indicated an emphasis on summer peak demand.

[17] Ameren's 2023 IRP Executive Summary, page 13.

Q WHAT AMOUNT OF WHOLESALE ENERGY COST HAS STAFF IDENTIFIED AND ALLOCATED ON ENERGY?

A Staff's CCOSS shows wholesale energy costs of about $1.0 billion.[18] Staff then allocates this cost using its proposed energy allocator based on the MISO Day Ahead LMPs.

Q HOW DID STAFF DEVELOP THE REVENUE REQUIREMENT ASSOCIATED WITH THE WHOLESALE ENERGY COST?

A Staff's testimony does not explicitly discuss this. However, a review of Staff's workpaper shows that it is derived from Generation Revenues less Schedule 26A expenses and the net Market Production and Transmission ("Net MP&T") expense.

Q DO YOU AGREE WITH STAFF'S WHOLESALE ENERGY COST?

A No. Staff's methodology effectively shifts about $1 billion of the total production revenue requirement to a revenue requirement item that it proposes to allocate on energy. I state this because Staff's functionalized revenue requirement for production Type 1 and Type 2 resources amounts to $1.563 billion.[19] However, it ultimately allocates only about $437.447 million[20] of that revenue requirement using its recommended Type 1 and Type 2 production cost allocators.

[18] Direct Testimony of Sarah Lange at page 45, table at lines 11-12.

[19] Shown on the MP&T tab of Staff's CCOSS workpaper. For Type 1 resources, the functionalized revenue requirement is equal to the Net Cost to Generate less Capacity Sales, consistent with the table on page 18 of Ms. Lange's Direct Testimony. For Type 2 resources, the Net Cost to Generate shown on page 18 of Ms. Lange's Direct Testimony is less than the Net Cost to Generate identified in Staff's CCOSS workpaper on the MP&T tab. The sum of the functionalized revenue requirement for Type 1 and Type 2 resources from Staff's workpaper is about $1.563 billion.

[20] Reflects the sum of the Net Revenue Requirement values shown on the MP&T tab of Staff's CCOSS workpaper. This differs from the Net Revenue Requirement values identified from Type 2 resources shown in the table on page 18 of Ms. Lange's Direct Testimony.

Q WHAT IS THE IMPACT OF STAFF'S PRODUCTION ALLOCATION METHODS ON THE LPS CLASS RELATIVE TO THE COMPANY'S APPROACH?

A It is challenging to precisely identify the impact of Staff's production cost allocation methods on the LPS class relative to the Company's approach, as Staff and the Company have functionalized cost of service components such A&O costs differently. However, AMO's CCOSS shows that about 9%[21] of its production revenue requirement (inclusive of a portion A&O costs) has been assigned to the LPS class, whereas Staff has assigned about 10%[22] of its production revenue requirement (exclusive of A&O costs) to the LPS class. The approximate 1% difference equates to about an additional $16 million[23] allocated to LPS under Staff's proposal, which is likely understated as it does not account for the production-related portion of Staff's A&O revenue requirement which has been allocated entirely on energy.

Q DO YOU HAVE ANY OTHER COMMENTS ON STAFF'S PROPOSED ENERGY ALLOCATOR?

A Yes. The DA LMP effectively is the incremental energy cost, that is the energy cost on the margin, and not the average energy cost. Ameren Missouri and the other Missouri utilities are regulated on the basis of their actual or embedded cost, not on the basis of incremental or marginal cost. To fit within the overall embedded cost revenue requirement upon which the Ameren Missouri and the other Missouri utilities are

[21] AMO's "MO ECCOS_2024 Final" workpaper, "Unbundled" tab. Cells AX77 and AX78 sum to an LPS production revenue requirement of about $164.5 million. Cells AS77 and AS78 sum to a total system production revenue requirement of about $2 billion. $0.1645 / $1.9153 = 8.6%.

[22] Staff's LPS production revenue requirement is about $140 million (derived from the table at the bottom of page 19 of Ms. Lange's direct testimony). Staff's total production revenue requirement is about $1.441 billion (also derived from the table at the bottom of page 19 of Ms. Lange's testimony). $0.140 / $1.441 = 9.7%.

[23] (9.7% - 8.6%) x $1.441 billion = $16 million.

regulated requires some "scaling" or other means of adjusting the incremental cost back down to the embedded cost. Staff has not been explicit about how this is accounted for.

Q WHAT IS YOUR RECOMMENDATION REGARDING STAFF'S RECOMMENDED ALLOCATION OF PRODUCTION ENERGY COSTS?

A Staff's proposed development of a Wholesale Energy Cost revenue requirement, and its proposed allocation based on MISO LMPs should be rejected. Staff's proposed approach results in an inappropriate allocation of about $1 billion of production capacity-related revenue requirement on the basis of energy. In addition, as described in footnotes 15 and 16, there are discrepancies between the revenue requirement information provided in Staff's testimony and the data provided in its CCOSS workpaper.

Staff's Allocation of Distribution Costs

Q STAFF COMMENTS ON AMEREN MISSOURI'S RECORDKEEPING AND ASSIGNMENTS WITHIN THE DISTRIBUTION FUNCTION. DO YOU HAVE ANY COMMENTS ON STAFF'S ISSUES WITH RESPECT TO DISTRIBUTION SYSTEM ALLOCATION?

A Staff states that the Company has provided significantly more detail than has been provided to Staff in the past regarding the utilization of poles at various voltages, and customer-specific infrastructure.[24] However, Staff asserts that there are limitations to its CCOSS due to the "limited data available."[25] Staff also suggests several times that

[24] Direct Testimony of Sarah Lange at page 8, lines 9-12.
[25] *Id.* at page 9, lines 15.

information is not available,[26] and highlights the inability to identify customer-specific infrastructure.[27] Based on these comments, Staff seems to think that the inability to identify the costs associated with specific distribution lines and other delivery equipment makes Ameren Missouri's studies imprecise and unreliable.

Q WHAT IS YOUR RESPONSE?

A While any set of records probably could be made more precise, the question is whether or not the added degree of precision would add useful or meaningful information and improve the accuracy of cost allocation studies. Knowing the exact cost (and depreciated value) of a specific 34 kV line running from Point A to Point B as compared to the average cost per mile of all 34 kV lines is not particularly meaningful when rates are set on the basis of general categories of customers and voltage level. Customers taking service at 34 kV are allocated a share of the costs of 34 kV and higher voltage equipment. Rates are designed to serve all 34 kV customers as a class, without regard to their specific geographic location, or the age of the facilities specifically providing service. In other words, unless rates were to be set separately for each individual customer, the added information would be of no value.

Q PLEASE DISCUSS STAFF'S PROPOSALS WITH RESPECT TO DISTRIBUTION PLANT IN FERC ACCOUNTS 364 THROUGH 367.

A Staff spends a considerable amount of time describing its proposals regarding these distribution accounts on pages 24 through 40 of Ms. Lange's testimony. As described in this section of her testimony, Ms. Lange proposes different customer/demand

[26] *Id.* at page 26, lines 8-9; page 28, line 14; page 33, lines 8-9, lines 14-15; page 38, line 3; page 41, line 10

[27] *Id.* at page 29, line 11; page 33, lines 9-10; page 38, line 4.

classifications of distribution costs and different allocations of demand-related costs than proposed by the Company.

Further, she proposes to subfunctionalize her demand-related portion of costs within those accounts and proposes different allocations of those subfunctionalized costs. For costs in FERC Account 364, she proposes to allocate her subfunctionalized demand-related costs on a combination of 4-NCP Summer demand, 12-NCP demand, and 12-CP demand depending on delivery voltage.[28] Her approach for FERC Accounts 365, 366 and 367 follows the approach for Account 364, although there were no secondary costs to allocate in these accounts.[29]

Q DID STAFF AKNOWLEDGE SHORTCOMINGS IN THE DATA IT USED TO DEVELOP THE CUSTOMER-RELATED PORTION OF DISTRIBUTION PLANT IN FERC ACCOUNT 364?

A Yes. Staff notes that it relied on Continuing Property Record ("CPR") data from the Company to develop its distribution classifications.[30] For Account 364, Ms. Lange indicates that Staff tried to graph certain data to develop a minimum intercept value.[31] However, it claims the resulting cost was unreasonable indicating anomalous data.[32] Ms. Lange further explains that Staff unsuccessfully attempted to refine the data.[33]

[28] Direct Testimony of Sarah Lange at page 27.
[29] *Id.* at page 33, lines 1-3; page 37, lines 11-14; and, page 3, lines 6-8.
[30] *Id.* at page 20, lines 10-13.
[31] *Id.* at page 24, lines 9 -11.
[32] *Id.* at lines 11-13.
[33] *Id.*

Q DESPITE THE ISSUES STAFF IDENTIFIED WITH THE CPR DATA, DID IT PROCEED TO RELY ON THE DATA FOR DEVELOPING ITS CUSTOMER CLASSIFICATION OF COSTS IN ACCOUNT 364?

A Yes.

Q DID STAFF ALSO RELY ON THE CPR DATA TO DEVELOP THE CUSTOMER CLASSIFIED PORTION OF ACCOUNTS 365 THROUGH 368?

A Yes, it appears so.

Q WHAT IS THE EFFECT OF STAFF'S RECOMMENDED APPROACH TO CLASSIFYING DISTRIBUTION COSTS?

A The effect of Staff's methods is that the portion of the distribution costs in FERC Accounts 364 through 368 classified as customer-related is reduced relative to the Company's CCOSS. Staff's approach and the corresponding result have not been justified. Staff has not explained why the Company's approach to distribution cost classification is inaccurate or unreasonable. Further, Staff's distribution cost classifications are based on data it repeatedly characterizes as unreliable or insufficient.

Q IS MS. LANGE'S PROPOSED APPROACH TO DISTRIBUTION COST CLASSIFICATION AND ALLOCATION CONSISTENT WITH THE NARUC MANUAL?

A No. Ms. Lange acknowledges in multiple instances that her approach is more detailed than required by the NARUC Manual,[34] but has not shown that it is better.

[34] *Id.* at page 31, lines 6-7, and page 35, lines 1-2.

Q STAFF DIRECTLY ASSIGNED THE COSTS OF CERTAIN SUBSTATIONS TO THE LPS CLASS. DO YOU AGREE WITH THIS APPROACH?

A No. Staff has directly assigned the costs of four substations to the LPS class, based on the Company's response to Staff Data Request 0601.[35] This data response does not indicate that the four substations assigned to the LPS class are even used by customers in the LPS class. Further, Staff has not explained whether these substations were originally designed and intended to exclusively serve individual customers, or whether that is simply the current status of the substations.

Q ARE THERE ANY OTHER ISSUES WITH STAFF'S PROPOSED ALLOCATION OF SUBSTATION COSTS?

A Yes. After the direct assignment of certain substation costs to the LPS class, Staff did not remove the demand units that it believes are exclusively served by these substations from the allocation factor for the LPS class. I state this because Staff's 12CP demand allocator that is uses to allocate these costs reflects the same LPS loads used in the Company's CCOSS for July 2023 through March 2024, which did not reflect any direct assignments of substation costs.[36] Thus, under Staff's approach, the demand that Staff believes is served by the directly assigned substations is double counted (i.e. that load receives a direct assignment, and also receives an allocation of the remaining system substation costs).

[35] *Id.* at page 23, lines 10-13.

[36] This can be seen by comparing the 12CPs in Staff's "CCOS Inputs" workpaper to the Company's 12CPs from its CCOSS workpaper.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING STAFF'S PROPOSED CLASSIFICATIONS AND ALLOCATIONS AND DISTRIBUTION COSTS.

A I recommend that Staff's proposed distribution cost classifications and allocations be rejected. As explained above, Staff's recommendations are based on unreliable data, unsupported assumptions, and are not consistent with the methods identified in the NARUC Manual.

Staff's Allocation of A&O Expenses

Q HOW DOES STAFF PROPOSE TO ALLOCATE THE REVENUE REQUIREMENT ASSOCIATED WITH A&O COSTS?

A Staff proposes to allocate the cost of the Commission Assessment and the net rate base element of Sales and Use Taxes in proportion to each class's share of revenue.[37] Staff proposes to allocate the remaining administrative and overhead costs on the basis of energy sales.[38]

Q PLEASE DESCRIBE THE ELEMENTS THAT STAFF HAS INCLUDED IN THE A&O CATEGORY.

A Staff's testimony identifies A&O expenses of $488.3 million, and A&O rate base of about $1.8 billion. Staff's testimony does not offer details about the elements it includes in these cost of service line items. However, a review of Staff's CCOSS workpaper shows that this category includes items such as Uncollectible Expense, Customer Service expenses, Sales expenses, Administrative and General ("A&G") expense, and

[37] Direct Testimony of Sarah Lange at page 42, lines 17-18 through page 43, line 1.
[38] *Id.* at page 43, lines 7-8.

amortization expenses including those associated with Plant In Service Accounting ("PISA").[39]

Q DO YOU AGREE WITH AN ENERGY ALLOCATION OF NON-REVENUE-RELATED A&O COSTS?

A No. Staff's broad-based allocations ignore the more precise assignments and allocations that Ameren Missouri has made in its class cost of service study. In addition, in some instances, Staff has allocated these costs on class energy usage, which is entirely without support.

Q HOW ARE COSTS OF THIS NATURE GENERALLY HANDLED IN CLASS COST OF SERVICE ANALYSES?

A Traditionally, these kinds of expenses are allocated across functions (generation, transmission and distribution) and between demand-related, energy-related and customer-related costs on the basis of the relationship between these costs and the costs in the specific functional categories.

According to the NARUC Manual, the typical allocation described above rests on the theory that A&O plant supports the other plant functions.[40] In addition, the NARUC Manual does not suggest energy as the basis for the allocation of A&O plant and expenses.

[39] Staff's "CCOS Study" workpaper, "Income Statement" tab.
[40] 1992 NARUC Manual, page 105-106.

Q WHAT IS STAFF'S EXPLANATION FOR ITS BROAD-BASED TREATMENT?

A Staff recommends these costs be allocated on the basis of energy sales, as the basic product of an electric utility.[41]

Q HOW DO YOU RESPOND TO THAT CLAIM?

A First, Staff's statement that energy is the basic product of an electric utility is an oversimplification of the role and offerings of electric utilities. Electric utilities provide and maintain sufficient generation capacity to meet peak demand, as well as provide and maintain transmission and distribution infrastructure which enables the delivery of energy to end users. Further, electric utilities provide customer-focused services such as energy efficiency consultations, green energy options, and they assist with facilitating the integration of distributed generation resources.

Second, I would acknowledge that some of these investments and expenses do require allocation among functions because they are incurred on a general enterprise basis and support the activities being conducted within the different functional areas. The fact that they may not be "precisely" assignable does not justify a failure to make reasonable assignments and allocations, and instead lump everything into one bucket and arbitrarily allocate those costs to customer classes on the basis of class energy requirements or some other general basis that have no relation to cost of service. A reasonable allocation of these costs across the functions, even if not precisely accurate, is more cost-based and far better than the arbitrary and totally inaccurate allocation of all of these costs on the basis of class energy requirements or some other general basis.

[41] Direct Testimony of Sarah Lange at page 43, lines 7-8.

Staff's recommended A&O cost allocation assigns approximately an additional $24 million[42] to the LPS class relative to the more traditional approach that it used for "validation of its CCOSS results." This does not reflect a reasonable allocation of these costs and should be rejected.

Q HAVE YOU QUANTIFIED THE TOTAL IMPACT ON THE LPS CLASS OF STAFF'S COST ALLOCATION METHODS?

A Yes. In total, I estimate that Staff's CCOSS allocates about $61 million[43] more to the LPS class than AMO's CCOSS at Staff's proposed revenue requirement. Approximately two-thirds of this difference is related to Staff's allocation of production and A&O costs, as described earlier in this testimony.

Staff's Recommended Revenue Allocation

Q WHAT IS STAFF'S RECOMMENDATION REGARDING CUSTOMER CLASS REVENUE APPORTIONMENT?

A Staff recommends reallocating about $2.6 million of revenue requirement from the Small General Service ("SGS") class, and about $3.5 million from the Lighting class to LPS and Large General Service/Small Primary Service customers,[44] followed by an equal percent increase across customer classes.[45]

[42] The total LPS cost of service is about $275 million per the table on page 45 of Ms. Lange's testimony. The more traditional allocation of A&O revenue requirement produces a total LPS cost of service of about $251 million (i.e. Net Expense of $185 million + (Net Rate Base of $926 million x 7.09% Rate of Return) from the second table on page 43 of Ms. Lange's testimony).

[43] Staff's recommended CCOSS allocates about 8.4% of the total revenue requirement to the LPS class, while AMO's CCOSS allocates about 6.5% of the Company's claimed total revenue requirement to the LPS class. The difference is about 1.9%. 1.9% of Staff's total revenue requirement is about $61 million.

[44] *Id.* page 45, lines 6-9.

[45] *Id.* in the table on line 12.

Q DO YOU AGREE WITH STAFF'S RECOMMENDED ALLOCATION OF ANY CHANGE IN REVENUE REQUIREMENTS?

A No. Staff's recommendation is based on its flawed CCOSS and should be rejected. Instead, any change in class revenue requirements should be allocated in accordance with the recommendations made in my direct testimony. Specifically, for the major rate classes I recommended revenue-neutral adjustments to revenues at current rates equal to 33% of the amount needed to move to cost of service. Any approved overall change in revenue should be applied as an equal percent to the base rate revenues of all classes after making the interclass adjustments. My recommended revenue allocation makes a meaningful movement toward cost of service based on the Company's CCOSS, while still reflecting the need for gradualism.

IV. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A As described throughout this testimony, the cost allocation recommendations made by CCM and Staff are inconsistent with cost causation and should be rejected.

In addition, Staff has not explained why it believes an entirely new cost allocation approach is warranted in this case. Further, Staff's CCOSS is unnecessarily complicated, relies on unsupported assumptions, and is not consistent with generally accepted practices.

I continue to support the Company's CCOSS as a reasonable measure of the cost of providing service to each class and recommend that AMO's CCOSS be used as the basis for revenue allocation in this case. I continue to recommend revenue-

neutral adjustments to move all major classes 33% of the way toward cost of service, followed by the application of any approved revenue change on an equal percent basis.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.