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Witness: Caroline Palmer
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MISSOURI PUBLIC SERVICE COMMISSION

Case No.: ER-2024-0319

Direct Testimony of Caroline Palmer

(Cost of Service Study/Rate Design)

On Behalf of

Consumers Council of Missouri

December 17, 2024

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I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, title, and employer.

A My name is Caroline Palmer. I am a Principal Associate at Synapse Energy Economics, Inc. ("Synapse"), located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q Please describe Synapse Energy Economics, Inc.

A Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 40 professional staff with extensive experience in the electricity industry.

Q Please summarize your professional and educational experience.

A I am a Principal Associate at Synapse where I provide expert witness and consulting services on behalf of public interest clients in regulatory proceedings. The issues I cover in these cases include marginal and embedded cost-of-service studies, revenue apportionment, advanced rate design, load management, decoupling, distributed energy resource (DER) interconnection and compensation, electric vehicle (EV) infrastructure investments, and pilot frameworks. Prior to joining Synapse I worked at Strategen

Consulting for five years performing similar work. I have submitted expert testimony in eleven dockets across six jurisdictions.

I was awarded a Fulbright Research Fellowship in Greece in 2019 and supported clean energy policy consulting at Meister Consultants Group (now Cadmus) before that. I hold a Master of Public Policy from the Goldman School at UC Berkeley and a Bachelor of Science from Georgetown University. I have 10 years of professional experience. My resume is attached as Attachment CP-1.

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

A Yes, I am sponsoring revenue requirement testimony, filed earlier in the instant proceeding. I have also sponsored testimony before several other commissions, including the New York Public Service Commission, the Massachusetts Department of Public Utilities, the Maine Public Utilities Commission, the Oklahoma Corporation Commission, the North Carolina Utilities Commission, and the Nova Scotia Utility and Review Board. I have also assisted with testimonies and regulatory analyses in numerous other jurisdictions.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of the Consumers Council of Missouri (Consumers Council).

Q What is the purpose of your testimony?

A I address certain aspects of Ameren Missouri's (Ameren Missouri or Company) class cost of service study (CCOSS), revenue allocation, and rate design proposals. I reserve the right to comment on other issues during rebuttal or surrebuttal, in response to proposals offered by other parties, or information that becomes available after I prepared this

testimony. The absence of discussion of other topics in this testimony should not be construed as support for, or opposition to, the Company's positions.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q Please summarize your conclusions.

A My conclusions are as follows:

- The Company's use of the minimum system method for classifying substantial portions of its distribution system in its CCOSS does not accurately reflect cost-causation principles and inflates cost allocations to residential customers.
- The Company's CCOSS workpaper is not sufficiently transparent, as the results are based on hard-coded values in the model. This hinders the ability of the Commission and intervenors to comprehensively evaluate the impacts of alternative cost of service methods.
- The Company's revenue allocation proposal is reasonable and partially mitigates my concerns with the minimum system method used in the CCOSS.
- The Company's proposed residential fixed charge increase reduces customers' ability to control their own bills; it may discourage conservation and render energy efficiency and load management investments less cost-effective.

Q What are your recommendations?

A I recommend that the Commission:

- Reject the minimum system method and adopt the Basic Customer Method for distribution cost classification, which limits customer-related costs to those directly tied to the number of customers, such as metering and billing.

- Direct the Company to provide a version of its CCOSS model with all formulas intact, i.e., in which modifications to the classification methodologies or allocators on various tabs flow all the way through the model to the results.
- Approve the Company's revenue allocation proposal.
- Direct the Company to maintain its current residential monthly fixed charge at $9.00 and instead increase the volumetric rate in order to achieve the necessary revenue requirement increase.

III. COST OF SERVICE STUDY

Overview of Cost of Service Studies

Q What is the purpose of a CCOSS?

A A CCOSS is used to assign the utility's revenue requirement to each customer or rate class in proportion to the costs imposed on the system by those customers. Thus, a cost of service study seeks to determine what costs are incurred to serve each class of customers.

Q How is a CCOSS performed?

A An embedded cost of service study typically follows three steps: first, costs are functionalized by separating utility plant and expenses according to the primary functions served. Second, the functionalized rate base and operating costs are classified according to the primary cost driver, as related to energy/commodity, demand/capacity, or customer. Finally, the costs are either directly assigned to customers or allocated among customer classes using allocation factors based on energy use, demand/capacity maximums, or the number of customers.

Q How do analysts determine the appropriate approaches to cost classification and allocation?

A When selecting classification factors or allocators, the goal is to fairly allocate costs among different customer classes based on cost causation. Cost causation reflects the notion that the customer or set of customers that caused a cost should pay for the cost. To determine cost causation, analysts often rely on economic theory and power system engineering considerations.

Q In your view, has the Company selected appropriate CCOSS methods?

A No. The Company classifies portions of the electric distribution system as partially "customer-related" based on a flawed minimum system methodology. My testimony recommends an alternative approach that is better supported by economic theory and power system engineering.

Classification of Distribution System Costs Using a Minimum System Study

Q Did the Company classify certain distribution system costs as both customer-related and demand-related?

A Yes. The Company considers poles, conductors, cables, transformers, and services (FERC accounts 364, 365, 366, 367, 368, and 369) to have both demand- and customer-related components.[1] The Company used a minimum-size distribution system study (minimum system study) to determine the share of each of these accounts to classify as customer-related versus demand-related.

[1] Hickman Direct Testimony at 10-14.

Q What is a minimum system study?

A The minimum system study is a cost analysis that estimates what the cost of the distribution system would be if the total system inventory was composed of the smallest equipment size. For each FERC account evaluated, the Company considers the minimum-sized cost of all the equipment in the account to be customer-related, reasoning that those assets "would generally be deployed across the system if there was not a need to meet higher levels of customer demand."[2] The Company considers the remaining cost of the actual distribution system to be demand-related.

Q Does the minimum system study deem significant portions of plant to be customer-related?

A Yes. The Company's minimum system study classifies the vast majority of poles and services, half of overhead conductors and line transformers, and just under a third of underground conduits and conductors as customer-related.[3]

Q What are your concerns with the minimum system methodology?

A I have three concerns with the minimum system methodology:

- It does not align with the Company's treatment of customer costs;
- It inflates the costs classified as customer-related; and
- It is unsound to use as the basis for determining cost causation.

I discuss each concern below.

[2] Hickman Direct Testimony at 10.
[3] Workpaper "MO ECCOS_2024 Final" tab "Min Size AFs."

Q Why doesn't the minimum system methodology align with the Company's treatment of customer costs?

A After classifying customer-related costs, Ameren Missouri allocates those costs based on "the number of customers associated with each rate class."[4] This treatment complements the 1992 National Association of Regulatory Utility Commissioners (NARUC) *Electric Utility Cost Allocation Manual* ("NARUC Manual"), which defines customer costs as "costs that are directly related to the number of customers served."[5]

Although the minimum system study classifies large portions of distribution plant as customer-related, to be allocated on the number of customers, the cost of equipment in those accounts does not vary directly with the number of customers; rather, it varies with those customers' demand.

For example, if the Company adds a new residential customer with a negligible level of demand in a populated area, the additional distribution costs to serve that customer—aside from dedicated customer infrastructure—would generally also be negligible, because residential customers share the majority of the distribution system. A new customer would generally only impose costs for distribution system upgrades to the extent that the customer increases peak demand on the distribution system. Thus, these costs are primarily driven by demand, rather than by the number of customers. It is only when the distribution system must be expanded to a new geographic area that an incremental customer impacts distribution system costs independently from the customer's level of demand.

[4] Hickman Direct Testimony at 7.
[5] NARUC Manual at 20.

This example demonstrates that the presence of a residential customer does not necessarily impose additional distribution costs (apart from costs related to that customer's demand) unless the system must be expanded to a new geographic area. Thus, there is little justification for classifying costs in these accounts as customer-related.

Q Is it particularly inappropriate to classify the primary electric system as customer-related?

A Yes. Primary distribution voltage is 600 to 34,500 volts, while secondary distribution voltage is 600 volts or less.[6] The residential customer class typically does not receive service directly at primary voltages.[7] Per the example above, it is unreasonable to suggest that the installation of primary equipment is caused by the presence of an individual residential customer regardless of that customer's demand, when residential customers are served at either 120 or 240 volts, i.e., at a fraction of primary voltage.

Q Did the Company calculate a minimum system that meets customer demands?

A Yes. Any size of equipment in FERC accounts 364–369 will necessarily serve a portion of customers' demand. In fact, the Company's minimum system is so extensive that it appears to meet and even exceed certain customer classes' peak demand requirements. For example, the minimum size transformer can meet 25 kVA of demand,[8] while the average residential peak demand is well below that, at around 6.11 kW.[9]

[6] Hickman Direct Testimony at 17.
[7] The Company stated that based upon a review of metering information, one residential customer receives service at primary voltage. *See* Ameren Missouri response to data request CCM-4.
[8] Other minimum system equipment sizing was provided in terms of amps, not kVA. *See* Ameren Missouri response to data request CCM-5.
[9] The maximum sum of individual residential customer non-coincident peak (NCP) during the test year was 6,716,980, which, divided by 1,098,931 residential customers, produces an estimated average residential maximum demand of 6.11 kW. *See* Workpaper "MO ECCOS_2024 Final" tab "SUM IND NCP" and "Cust."

Q If the minimum size equipment is likely large enough to accommodate certain customer classes' peak demands, is it reasonable to classify such a large portion of the system as "customer-related"?

A No. Such a "minimum" system exceeds even the Company's intended theoretical scope, which is the minimum cost necessary to make electric service available regardless of usage,[10] not the cost of accommodating maximum usage. It is unreasonable to assign customers hefty distribution system costs based on such a flawed representation of the "customer" portion of the distribution system.

Q Describe other limitations of the minimum system methodology.

A Further sources of imprecision in the Company's minimum system study arise due to reliance on blunt accounting cost records. The minimum system FERC accounts include equipment that is constructed far upstream from individual customer loads and is thus typically built based on diversified, combined demands, not built based on the presence of individual customers. For example, plant accounting data does not distinguish sub transmission feeders,[11] which often connect high voltage distribution substations, from other circuits in FERC accounts 365–367. Thus, the Company includes these costs in its "minimum system" though they are likely driven by coincident peak demands at the substation. The substations themselves are classified as demand-related. Likewise, primary step transformers—which convert power voltage down to a lower level but do not directly connect customers' premises to the grid—are included in "the number of transformers [used] to determine the customer-related cost components for this

[10] Hickman Direct Testimony at 8.
[11] Ameren Missouri response to data request CCM-43.

account"[12] Including these costs in the hypothetical minimum system inflates the costs that are classified as customer-related by an unknown amount.

Q What are the impacts of using a study that inflates the costs classified as "customer-related"?

A Inflating the costs classified as customer-related—whether because of imprecise accounting data or by calculating a minimum system that may meet customer peak demands—has meaningful implications for the residential class. Customer-related costs are far more heavily allocated to residential customers compared to demand-related costs because the residential class has many more customer accounts than the other classes; thus, assigning costs based on the number of customers will allocate the majority of these costs to the residential class. Indeed, the CCOSS assigns residential customers 83 percent of the customer-related costs in accounts 364–368, compared to 51–61 percent of the demand-related costs in those accounts.[13]

Q Is the minimum system method unsound to use as the basis for determining cost causation?

A Yes. The method requires distinguishing a hypothetical system that serves only customers, not their electricity demand. To create this imaginary system, the Company makes subjective assumptions that oversimplify system engineering and impact the study results in unquantifiable ways. The accumulation of falsely precise approximations forms an unreliable basis on which the Company has assigned substantial costs among classes.

[12] Ameren Missouri response to data request CCM-42.
[13] Workpaper "MO ECCOS_2024 Final" tab "Min Size AFs" and "AF Sum Sht."

Q What method do you recommend instead of the minimum system method?

A I recommend classifying distribution costs using the basic customer method. As described in the Regulatory Assistance Project's manual *Electric Cost Allocation for a New Era*, this method is used by multiple states across the country and is intuitive and data-based, as it includes only costs that are directly related to the number of customers on the system. Specifically, the basic customer method generally classifies only costs associated with services, meters, meter reading, and billing as customer-related.

Not only has the basic customer method been used by utilities in numerous states,[14] in some cases public utility commissions have explicitly rejected the minimum system method or otherwise required that utilities classify primary and secondary distribution costs as 100 percent demand-related. For example:[15]

- The Arkansas Public Service Commission found that accounts 364–368 should be classified as 100 percent demand-related.
- The Illinois Commerce Commission has repeatedly rejected the minimum distribution or zero intercept approach.
- The Iowa Administrative Code requires customer cost allocations to only include costs of the distribution system related to transformers, meters, and associated customer service expenses.
- The Washington Utilities and Transportation Commission in 1993 directed the parties not to propose the minimum system approach in the future unless technological changes in the industry emerge, justifying revised proposals.

[14] For example, National Grid in Massachusetts does not use a minimum system study for classification. *See* Exhibit NG-PP-1 in D.P.U. 23-150 (November 16, 2023) at 18, stating "the Company has not performed a minimum system study in its last four distribution rate cases, or more, and…did not perform a minimum system study for this ACOSS."

[15] Lazar, J. et al., *Electric cost allocation for a new era: A manual.* Montpelier, VT: Regulatory Assistance Project (2020) at 145.

- Alaska administrative code prohibits customer-related costs from including "any portion of the distribution system costs, which will be considered and classified as demand-related costs."[16]

Q What is the impact of using the basic customer distribution classification?

A My recommendation impacts the class revenue requirements in the CCOSS, specifically the revenue requirement changes that would be necessary to achieve equal rates of return on rate base under the Company's proposed revenue requirement. Under the scenario with no minimum system (basic customer method), the required residential (1M) revenue increase falls to 21.6 percent from 24.1 percent.[17] Other class revenue requirements also change, such as the large GS/small primary (3M and 4M tariff labels) revenue increase rising from 4.6 percent to 8.8 percent.

This result is based on my best effort to modify the CCOSS, by adjusting the distribution classification factors. However, due to obstructions in the Company's model, described below, that prevent classification adjustments from flowing through to the CCOSS results, determining the impact of my adjustment required manually adjusting each cost category in the model. I updated the largest and thus most impactful categories (gross plant and depreciation reserve) but could not comprehensively modify the model.

[16] 3 Alaska Admin. Code § 48.540.
[17] Workpaper "Synapse_MO ECCOS_2024 Final" tab "SCH 2."

Q If the Commission chooses not to approve the basic customer method, would a hybrid classification method be more appropriate than the minimum system approach?

A Yes. If the Commission does not approve the basic customer method, there are ways to better align the minimum system study with system costs. In that case, I recommend that the Company classify primary distribution costs as 100 percent demand-related and only apply the minimum system methodology to secondary distribution costs, which are the lower-voltage lines that connect most customers to the grid.

Transparency and Accessibility of the Company's CCOSS

Q Were you able to fully model your recommendation in the Company's CCOSS?

A No. The model that the Company filed as a workpaper does not fully update when modified, thereby hindering the ability of intervenors to determine the full impact of any proposed CCOSS modifications. As described above, I modified the largest cost categories, but I was unable to comprehensively model the basic customer method due to the way the Company designed its model.

Q What steps did you take to determine the impact of your proposed CCOSS modifications?

A I first requested that the Company produce a CCOSS with limited changes;[18] the Company objected to my request and declined to implement alternative CCOSS methodologies. I then familiarized myself with the Company's CCOSS and input my changes. However, my modifications did not flow all the way through the CCOSS to the

[18] Data request CCM-15.

results in tab "SCH 2" because the Company hard-coded key inputs to the results, rather than having them flow through the underlying cost data. Specifically, key inputs to the results presented on tab "SCH 2" are drawn from a set of hard-coded cells on tab "EXP2" –cells that do not update despite changes made elsewhere in the model—rather than from the precedents on the "COST" tab that do update.

Q Did you request that the Company provide you with a version of the CCOSS that does not contain hard-coded values?

A Yes, I requested that the Company provide a version of the CCOSS "with all formulas intact, i.e., in which modifications to the cost of service study methodologies on various tabs flow through the model to the results on tab "SCH 2." The Company responded that its original workpaper "is the fully executable version of the file utilized to create the schedules…such as "SCH 2", changes in other tabs do flow through to the other tabs."[19] As described above, my experience is that the CCOSS workpaper model provided by the utility is not fully executable.

Q Why is it concerning that modifications to CCOSS methodologies do not flow through the model to the results?

A The ability to fully interact with the Company's CCOSS and implement recommended methodologies for the Commission's consideration is essential to enable meaningful intervenor contributions to the regulatory process. The inability to evaluate the impact of a particular recommendation is a barrier to engaging with the Company's proposals. The lack of transparency in the Company's modeling requires a significant amount of

[19] Ameren Missouri response to data request CCM-47.

unnecessary effort from an intervenor attempting to modify the model and can prevent an intervenor from presenting complete recommendations to the Commission.

Q What do you recommend regarding the Company's CCOSS model?

A I recommend that the Commission direct Ameren Missouri to file a version of the CCOSS with all formulas intact, i.e., in which modifications to the classification methodologies or allocators on various tabs flow through to the results such that relevant inputs to the results on tab "SCH 2" are not hard-coded.

IV. REVENUE ALLOCATION

Q How does the Company determine how much of a revenue increase to apportion to each of the customer classes?

A The Company made a series of revenue-neutral adjustments to classes' CCOSS revenue requirements to finalize allocations that the Company states represent a "movement towards the cost of service [that] is fair."[20] Ultimately, the Company proposes a range of percentage increases in revenue requirements for the customer classes (between 14.22 percent and 15.77 percent) based on the utility's overall revenue requirement request of 15.5 percent.

Q Do you support the Company's revenue requirement allocations?

A Yes. The Company has mitigated some of my concern around its CCOSS methodologies by exercising judgement when using its CCOSS to inform revenue allocation and rate design. As evidenced by the impact of a single methodological change that I described above, a CCOSS is an inherently imprecise tool in which an analyst makes numerous

[20] Bowden Direct Testimony at 30.

subjective determinations that may dramatically impact the results of the study. As such, utility cost of service studies should serve as one of several tools to inform decision-makers in revenue allocation and rate design, rather than being viewed as the sole determinant or final authority.

V. RATE DESIGN: RESIDENTIAL FIXED CHARGE

Q Describe the Company's residential fixed charge proposal.

A The Company proposes to increase the residential fixed charge from $9.00 to $10.43.[21] The Company proposes to increase all rates within each rate schedule—both fixed and volumetric—by an equal percentage based on the proposed percentage revenue requirement increase for the customer class.[22] Thus, the increase to the residential customer charge is equal to the proposed percentage increase in the overall residential class revenue requirement, or just under 16 percent.

Q Do you have concerns about the Company's customer charge proposal?

A Yes. Raising the customer charge reduces customers' ability to control their own bills by increasing the fixed portion of the monthly electric bill, over which customers have no control even if they can reduce their electricity consumption. The impact is more acute for low-usage customers whose bills are relatively smaller and therefore more influenced by the customer charge. Low-usage customers are also more likely to be low-income and have less ability to pay higher bills.

[21] Schedule NSB-D1 and Schedule NSB-D3.
[22] Bowden Direct Testimony at 32.

A higher fixed charge also means a lower volumetric charge than there otherwise would have been. Relatively lower volumetric charges paired with higher fixed charges can discourage conservation and render energy efficiency and load management investments less cost-effective; that reduces the value to customers of adjusting their usage and therefore increases the payback periods for said investments.

Q Do you support the Company's proposed residential fixed charge increase?

A No. I recommend that the Company maintain its current $9.00 monthly fixed charge and instead increase the residential volumetric rate as necessary in order to achieve the required revenue requirement increase.

VI. CONCLUSION

Q Does this conclude your testimony?

A Yes, it does.