Exhibit No.:	
Issue:	Class Cost of Study, Revenue Allocation, Rate Design
Witness:	Kavita Maini
Type of Exhibit:	Direct Testimony
Sponsoring Parties:	MECG
Case No.:	ER-2024-0319
Date Testimony Prepared:	December 17, 2024

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	**)))))**	**File No. ER-2024-0319**

Direct Testimony and Schedules of

Kavita Maini

On behalf of

MIDWEST ENERGY CONSUMERS GROUP

December 17, 2024

Protecting Your Bottom Line

KM ENERGY CONSULTING, LLC

**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 WISCONSIN	)	
	)	SS
COUNTY OF WAUKESHA	)	

AFFIDAVIT OF KAVITA MAINI

Kavita Maini, being first duly sworn, on her oath states:

1. My name is Kavita Maini. I am a consultant with KM Energy Consulting, LLC. having its principal place of business at 961 North Lost Woods Road, Oconomowoc, WI 53066. I have been retained by the Midwest Energy Consumers Group ("MECG") in this proceeding on its behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and schedules which were 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 and schedules are true and correct and that they show the matters and things that they purport to show.

Kavita Maini

Kavita Maini

State of Wisconsin
County of Waukesha

This instrument was signed before me on 12/17/2024 by Kavita Maini.

Signature of notary:
Notary public
Expiration date: 01/09/2027

SEBASTIAN KUBAS
NOTARY PUBLIC
STATE OF WISCONSIN

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Direct Testimony of Kavita Maini

I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is Kavita Maini. I am the principal and sole owner of KM Energy Consulting, LLC.

Q. Please state your business address.

A. My office is located at 961 North Lost Woods Road, Oconomowoc, WI 53066.

Q. Please state your educational and professional background.

A. I am an economist with over 32 years of experience in the energy industry. I graduated from Marquette University, Milwaukee, Wisconsin with a Master's degree in Business Administration and a Master's degree in Applied Economics. From 1991 to 1997, I worked for Wisconsin Power & Light Company ("WP&L") as a Market Research Analyst and Senior Market Research Analyst. In this capacity, I conducted process and impact evaluations for WP&L's Demand Side Management ("DSM") programs. I also conducted forward price curve and asset valuation analysis. From 1997 to 1998, I worked as Senior Analyst at Regional Economic Research, Inc. in San Diego, California. From 1998 to 2002, I worked as a Senior Economist at Alliant Energy Integrated Services' Energy Consulting Division. In this role, I was responsible for providing energy consulting services to commercial and industrial customers in the area of electric and natural gas procurement, contract negotiations, forward price curve analysis, rate design and on-site generation feasibility analysis. I was also involved in strategic planning and due diligence on acquisitions.

Since 2002, I have been an independent consultant. In this role, I have provided consulting services in the areas of class cost of service studies, rate design, revenue allocation, resource planning and revenue requirement related issues, Midcontinent Independent System Operator ("MISO") related matters and various policy matters. I also represent industrial trade associations at MISO's various task forces and committees and am the End Use Sector representative at MISO's Advisory and Planning Advisory Committees.

Q. Have you participated in utility related proceedings?

A. Yes, I have testified before a number of state regulatory commissions, including in Wisconsin, Minnesota, Missouri, Iowa, North Dakota and South Dakota. I have testified on a variety of issues related to revenue requirements, resource planning and generation resource acquisition, cost of service, revenue allocations and rate design. I have also provided technical comments in Federal Energy Regulatory Commission ("FERC") proceedings, several of which have involved MISO-related activities.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying as an expert witness on behalf of the Midwest Energy Consumers Group ("MECG"). The MECG is an incorporated entity representing the interests of large commercial and industrial customers including those taking service from Union Electric d/b/a Ameren Missouri's. ("Ameren Missouri" or "Company") on its Large General

Service ("LGS"), Small Primary Service ("SPS") and Large Primary Service ("LPS") rate schedules.

Q. How are the companies represented by MECG impacted by this proceeding?

A. I am advised that many of companies whose interest MECG represents operate energy intensive facilities and compete in a regional and national environment. Therefore, energy costs are typically among the primary costs of doing business for these companies. Thus, energy affordability affects the competitiveness, output and potential employment levels for these companies.

In this rate case proceeding, Ameren Missouri proposes an approximately $446 million increase in revenue requirement or 15.5% increase on a systemwide basis. For this increase, the Company proposes a 15.5%, 14.94% and 14.22% increase to the LGS, SPS and LPS cases respectively while the Company's own cost of service study supports much lower increases at 4.6% for the LGS/SPS classes and -0.8% for the LPS class. The large commercial and industrial customers members served by Ameren Missouri will therefore be significantly impacted by the outcome of this proceeding.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss and provide recommendations regarding the Company's: (a) class cost of service study ("COSS"); (b) an appropriate allocation approach for any rate change; and (c) rate design for the LGSSPS and LPS rate schedules. The rest of my testimony is organized as follows:

Section II: Summary

Section III: Class Cost of Service Study

Section IV: Revenue Requirement Allocation

Section V: LGS, SPS and LPS Rate Design

The fact that an issue is not addressed herein should not be construed as an endorsement of, agreement with, or consent to any filed position.

II. SUMMARY

Q. Please summarize your testimony and recommendations.

A. The following is a summary of my testimony and recommendations:

Section III: Class Cost of Service Study ("COSS")

a) A COSS study is critical in establishing fair and reasonable rates because it: (i) guides how the revenue requirement should be allocated to classes and (ii) informs rate design. Thus, it is important that the COSS approach reflect cost causation.

b) Either the Peak Demand or the Average & Excess (A&E) method are reasonable allocation methods for fixed production plant-related costs; the Company uses the A&E approach, and I support this method in this case.

c) The A&E methodology to calculate the production cost allocator considers the load profile of customer classes by incorporating the class's maximum demands, load factor and average energy use. The A&E method is used by Ameren, Liberty-Empire and Evergy respectively.

d) The Company's A&E approach used to calculate the excess demand portion relies on the average of four non-coincident peak ("NCP") demands for each customer class regardless of when those NCP occurred during the year. I recommend the class average of the four highest non-coincident peaks, which is consistent with the method described in the NARUC Manual and Section 393.1620.1 (1) of the Missouri Statute.

e) I recommend that the Commission adopt MECG's COSS. Given the substantial similarity in results, however, MECG would not be opposed to the Commission adopting Ameren Missouri's COSS.

Section IV: Revenue Requirement Allocation

a) The COSS methodology is reasonable and produces reliable results to be used as guidance for revenue apportionment to classes.

b) The COSS should be used as the primary guiding principle in allocating revenue requirement to classes and informing rate design. Such an approach will foster equity amongst classes, send appropriate price signals and encourage economic efficiency. While other factors such as gradualism and rate continuity may also be considered, these factors should not be the dominating elements such that there is little to no movement towards class cost responsibility.

c) Both the Company and my COSS results show that at present rates and equal rates of return, the residential and lighting classes are paying rates that are substantially below cost responsibility. All other classes are paying rates above their class cost responsibility.

d) I recommend a 25% revenue neutral adjustment to all classes prior to applying an equal percent increase associated with the final authorized revenue requirement. The recommended revenue neutral shifts would help in incorporating fairness systematically among classes while at the same time, a 25% revenue neutral shift recognizes that moderation is necessary and to not align 100% with the COSS results.

Section V: Rate Design

1. LGS and SPS Rates

a) The current LGS and LPS rates substantially over recover costs from energy charges and under recover costs from demand charges as compared to the cost of service study results. The resulting rate design sends inefficient pricing signals.

b) Aside from the disparity and inconsistency with the COSS results, the Company's proposed increases in the current rate case are predominantly fixed costs and associated with capital investment and depreciation expenses. Fixed costs do not vary with energy consumption and should be recovered from demand charges. Therefore, the primary drivers in the case support higher increases to demand charges versus energy charges.

c) I recommend the Company's proposed adjustments to all rate components except demand and energy charges. The summer and winter demand charges should be increased by 150%. The remaining revenue requirement should be recovered by equal percentage increases to all blocks of summer and winter energy charges.

d) I recommend that the Company provide a progress report as well as a timeline by when it intends to propose alternative or optional rate design proposals applicable to non-residential classes.

2. LPS Rates

Compared to LGS and LPS rates, the current LPS rate design appropriately recovers a substantial portion from demand charges. I am not opposed to the Company's proposal for an equal percent increase to energy, demand and customer charges.

III. COST OF SERVICE

A. Importance of A Utility's Cost of Service Study

Q. What is the importance of a utility's cost of service study?

A. A utility's cost of service study is the fundamental basis for establishing just and reasonable rates in the ratemaking process. The cost of service study helps determine a utility's revenue requirement, guides revenue allocation to classes and informs rate design.

Revenue Requirement: A utility's cost of service is used in the determination of the revenue requirement of the utility and whether an increase, decrease or no change is necessary. Efforts are made to align total company rate revenues with the utility's cost of service.

Revenue Allocation to Classes: Given a certain revenue requirement, a utility's cost of service study guides the way in which a given revenue requirement should be allocated to classes. The level of the revenue requirement for each class should be based primarily on aligning each class's revenues with its cost of service providing the same or equal rates of return.

Setting Rates: For a certain revenue allocation to each class, a utility's cost of service also informs the design of class rates by setting rates with the goal of providing appropriate pricing signals.

Q. For a given revenue requirement, what is the impact of closely aligning rates with the costs to serve each class?

A. Provided that the class cost of service study is properly developed to reflect cost causation, closely aligning rates with each class's cost of service fulfills the important goals of promoting equity among classes and encouraging economic efficiency.

Q. Please explain how equity is promoted among classes.

A. If rates are aligned with the cost of service, then equity is promoted because each class pays its fair share of costs. That is, a class is neither subsidizing another class nor is it being subsidized.

At a minimum, the rate increases to each class must be directionally consistent meaning that a class that has rates that are not recovering its cost of service should receive an above system average increase while a class paying rates above cost of service should receive a below average increase. In cases where the class revenues are significantly misaligned with cost responsibility, larger corrections or adjustments may be warranted in order to restore equity among classes.

Q. How is economic efficiency achieved?

A. If retail rates align with the cost of service, then they provide accurate pricing signals that drive consumer behavior, which in turn results in more efficient use of the system and minimizes system costs. For example, in instances where the class rates are set above cost, say for the industrial class, the resulting rates would incent customers in this class to reduce production or shift production elsewhere. Such a consequence results in higher costs for all customers since the utility's fixed costs would need to be recovered from a lesser number of billing determinants. The Commission expressly recognized this fact in 2014 in a Liberty Empire rate case when it found that "if businesses leave Empire's service area, Empire's remaining customers bear the burden of covering the utility's fixed costs with a smaller amount of billing determinants."[1] On the other hand, for classes where rates are set at artificially low levels, then the rates are not sending the price signal that those customers should engage in energy efficiency measures.

Economic efficiency is not only affected by the misallocation of the revenue requirement among the rate classes, but also impacted by the class rate design. In instances where the class revenue responsibility is at the cost of service, but rates are designed such that there is recovery of fixed costs through volumetric charges, then the pricing signals are distorted and have the potential once again of sending inappropriate cost signals. For example, if fixed generation costs are recovered through variable charges, then the demand charge is kept artificially low, thus sending the improper price signal that generation capacity is cheaper than is actually the case. Similarly, if the energy charge is artificially high then there is an implication that energy costs are more expensive than is actually the case. Such a signal could then result in customers choosing to use less energy but contributing more to peak conditions. This has the effect of increasing the need for capacity, thereby increasing system costs, which once again, must be recovered from customers through higher rates.

B. COSS Steps

Q. What are the different steps involved in the cost of service process?

A. A cost of service study generally follows three basic steps. First, the various costs are identified as production, transmission, and distribution (functionalization step). Next, these functionalized costs are classified as demand-related; energy-related; or customer-

[1] See the Commission's decision in ER-2014-0351.

related (classification step). Finally, these classified costs are allocated among the various rate classes based upon factors which attempt to measure each customer class's contribution to that total classified cost (allocation step).

Functionalization: Various costs are separated according to function such as generation, transmission, distribution, customer service and administration. To a large extent, this is done in accordance with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts.

Classification: The functionalized costs are classified based on the components of the utility service being provided and the underlying cost causative factors. As described by the NARUC Manual, the three principal cost classifications are: (1) demand-related costs (costs that vary with the kW demand imposed by the customer), (2) energy-related costs (costs that vary with energy or kWh that the utility provides), and (3) customer-related costs (costs that are directly related to the number of customers served). See NARUC Manual page 20.

Allocation: Once the costs are classified as demand-related, energy-related or customer-related, they are then allocated to classes using the relevant demand, energy or customer allocators. Each of these allocators measures each class's contribution to the total system cost.

Each of the three steps – functionalization, classification, and allocation, is very important because it sets the foundation for developing rates and sending accurate pricing signals. If costs are improperly functionalized, classified or allocated, they result in cross subsidies and economically inefficient pricing signals in rate design.

C. COSS: Fixed Production Plant Cost Allocation

Q. What are fixed production plant-related costs?

A. Fixed production plant-related costs are costs that are functionalized as production related and incurred in acquiring or procuring generation resources. Utilities are required to build or acquire sufficient generation capacity to ensure that they can reliably meet system peak demands. Primarily, these costs consist of the fixed investment in power plants, but do not include the variable cost (e.g., fuel) of generation. These costs include return on and of investment and fixed operations and maintenance costs. Once the generation investment is made, the costs are sunk costs, fixed in nature and do not vary with energy usage.

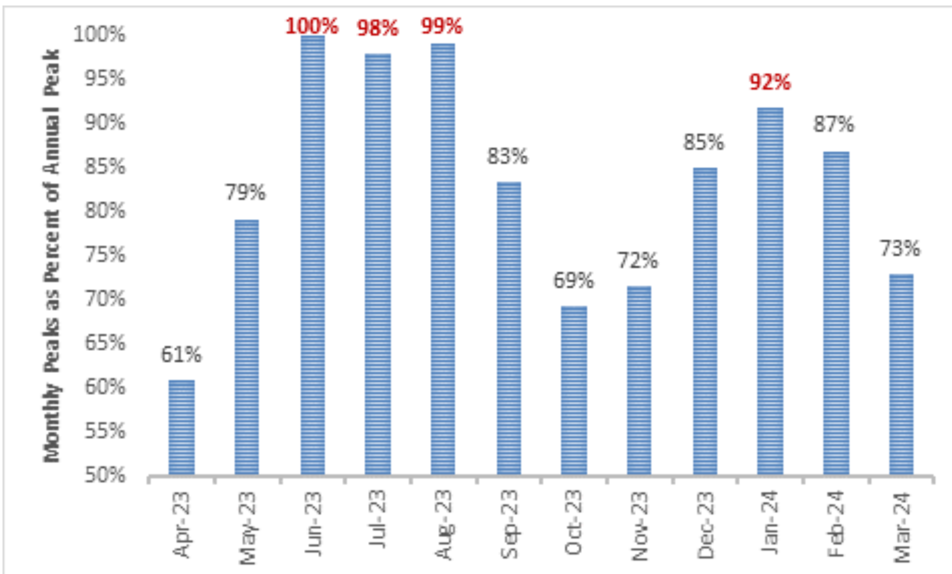
Q. What should be considered in determining the appropriate allocator for fixed production plant-related costs?

A. Since a utility needs to ensure that it has sufficient generation capacity to reliably meet its peak load requirements and must be sized to meet the maximum load or demand imposed on these facilities, the appropriate allocation method should reflect the annual load pattern and load characteristics of the utility (system peaks) and the annual system peak.

Q. Did you analyze Ameren Missouri's system load?

A. Yes, I did. Figure 1 shows the system monthly peak demands as a percentage of overall annual peak for the test year. This chart shows that Ameren Missouri's system maximum demand occurs in the summer with the highest peak occurring in June, followed by the second and third highest peaks also occurring in the summer in August and July respectively. The fourth highest peak occurred in January. Since generation capacity is sized to reliably meet the highest peak demands, it would be appropriate to consider class contributions to monthly demands for these fourmonths. Further, as I discuss later in this section, utilizing the non-coincident peaks for the four months with the highest system peak loads in calculating the average and excess production cost allocator, is also consistent with the Section 393.1620.1 of the Missouri Statutes.

Figure 1: Test Year Ameren Missouri's Monthly Peaks
As a Percent of Annual Peak



Q. What allocation methods are reasonable in allocating fixed production plant-related costs?

A. Either the Peak Demand method or the Average and Excess ("A&E") Demand method are reasonable methods for allocating fixed production costs.

In the Peak Demand method, the fixed production plant-related costs are allocated to rate classes on demand factors that measure the class contribution to system peak or peaks. As demonstrated above, in the Company's current case, class contributions coincident with the four highest demands of June through August and January would be appropriate to use in calculating the production cost allocator.

While the Peak Demand method relies solely on class contribution coincident to the relevant monthly peak demands, the A&E methodology considers demand as well as class energy usage. As the name implies, the A&E Demand method consists of an average demand component and an excess demand component. The average demand component, which considers the class energy, is calculated by dividing the energy usage of each class by the number of hours in a year. The excess component, which considers the class peak demand, is calculated as the difference between the customer class's maximum non-coincident peak or peaks and the average demand. The average demand component for each class is then weighted by the system load factor and the excess component for each class is weighted by 1-load factor.[2] The composite allocator is the sum of the weighted average and excess components.

The A&E approach considers the load profile of customer classes by incorporating the maximum demands, load factor and average energy use. While the average demand measures the duration, the excess portion measures the variability of the load profile of a class. For example, as noted in the Commission decision in its Report and Order in Docket ER-2010-0036 (pages 84-85),

> Some customer classes, such as large industrials, may run factories at a constant rate, 24 hours a day, 7 days a week. Therefore, their usage of electricity does not vary significantly by hour or by season. Thus, while they use a lot of electricity, that usage does not cause demand on the system to hit peaks for which the utility must build or acquire additional capacity. Another customer class, for example, the residential class, will contribute to the average amount of electricity used on the system, but it will also contribute a great deal to the peaks on system usage, as

[2] See NARUC Manual, page 49,81-82

> residential usage will tend to vary a great deal from season to season, day to day, and hour to hour.

Q. Are you familiar with Section 393.1620 enacted in 2021?

A. It is my understanding, from talking to counsel, that Section 393.1620 limits the Commission to considering class cost of service studies that utilize a method reflected in the NARUC manual for the allocation of fixed production plant costs associated with nuclear and fossil generating units. Specifically, Section 393.1620 provides:

> In determining the allocation of an electrical corporation's total revenue requirement in a general rate case, the commission shall only consider class cost of service study results that allocate the electrical corporation's production plant costs from nuclear and fossil generating units using the average and excess method or one of the methods of assignment or allocation contained within the National Association of Regulatory Utility Commissioners 1992 manual or subsequent manual.

Q. How is the average and excess method defined in Section 393.1620?

A. Section 393.1620.1 (1) defines the average and excess method as:

> A method for allocation of production plant costs using factors that consider the classes' average demands and excess demands, determined by subtracting the average demands from the <u>noncoincident peak demands, for the four months with the highest system peak loads.</u> The production plant costs are allocated using the class average and excess demands proportionally based on the system load factor, where the system load factor determines the percentage of production plant costs allocated using the average demands, and the remainder of production plant costs are allocated using the excess demands.

Q. Are the peak demand and A&E methods included in the NARUC Manual?

A. Yes, the Peak Demand and A&E methods are included in the NARUC manual. While the general approach is included in the NARUC manual, the manual appears to leave some discretion to the analyst regarding the specifics of application. For instance, the peak demand approach or the A&E approach could consider a single monthly peak or multiple month peaks. In terms of developing the allocator for Ameren Missouri, utilizing the class contribution to the Company's four highest system demands (shown in Figure 1) using the Peak Demand method or the A&E method are valid and reasonable approaches.

Q. What allocation method does the Company use for allocating fixed production plant related costs?

A. Similar to the past case, the Company uses the A&E method for allocating fixed production costs. The A&E method is a recognized and well established method. I support the Company's decision to continue to use the A&E method in this case.

Q. Has the A&E methodology seen widespread adoption by Missouri utilities?

A. Yes, the A&E methodology has been adopted by Ameren, Empire and Evergy respectively.

Q. What class peaks does Ameren Missouri use to calculate the excess demand portion?

A The Company's A&E approach used to calculate the excess demand portion relies on the average of four non-coincident peak ("NCP") demands for each customer class regardless of when those NCP occurred during the year.

Q. Is there an alternative approach to calculate the excess portion that would be more compatible with Section 393.1620.1 (1) of the State of Missouri's Statutes?

A. Yes. As observed in Figure 1, the Test Year system peak data shows that the four highest demands are in June, July, August and January respectively. Therefore, instead of using the average of the four NCP for each customer class regardless of when those NCPs occurred, the class average of the four NCPs for these four months with the highest system peak loads are used for calculating the excess portion.

Q. Have you calculated the A&E allocator using non-coincident peak demands for the four highest system peak loads?

A. Yes. I did. I used class non-coincident peak demands for the four highest system peak load months of June, July, August and January receptively (or 4NCP) to make this calculation.

Q. Please explain in detail the derivation of the A&E 4NCP allocator.

A. Figure 2 shows the derivation of the A&E 4NCP allocator.

Figure 2: Derivation of the A&E 4NCP Allocator

Column	1	2	3	4	5	6	7
	Peak Demand 4NCP (MW)	Energy Sales with Losses (MWH)	Average Demand (MW)	Excess Demand (MW)	Average Demand (%)	Excess Demand (%)	Total Allocator (%)
Residential (RES)	3,390.13	14,357,138	1,638.94	1,751.19	43.11%	64.06%	**51.55%**
Small General Service (SGS)	744.72	3,500,548	399.61	345.12	10.51%	12.62%	**11.36%**
Large General Service (LGS) / Small Power Service (SPS)	1,892.00	11,557,260	1,319.32	572.68	34.70%	20.95%	**29.16%**
Large Power Service (LPS)	489.68	3,752,966	428.42	61.25	11.27%	2.24%	**7.63%**
Lighting	28.85	134,171	15.32	3.38	0.40%	0.12%	**0.29%**
			-				
Total	6,545.38	33,302,082.6	3,801.61	2,733.62	100.00%	100.00%	**100.00%**

Column 1 shows the average of the four non-coincident peaks ("NCP") for the four peaking months by class. Column 2 shows the annual energy (MWh) with losses by class and Column 3 converts this annual energy (MWh) to average demand (MW) by dividing the annual energy usage by 8760 hours. The excess demand shown in Column 4 is calculated by subtracting the average demand in Column 3 from the NCP average demand for the four peaking months as reflected in Column 1. Column 5 shows each class's average demand share as a percentage of Ameren Missouri's system average demand. So, for instance the residential average demand percentage share is 1,638.94 MW divided by the total of 3801.51 MW or 43.11%. Column 6 then shows each class's excess demand share as a percentage of the total excess demand for all classes. So, continuing to use the residential class as an example, this component would be 1751.19 MW divided by 2733.62 MW or 64.06%. Column 7 represents that sum of (a) weighting class average demand as a proportion to the system average demand (Column 5) by the system load factor (59.72%) and (b) weighting the class excess as a proportion to the total excess demand (Column 6) by 1 minus the system load factor (40.28%). This method is consistent with the NARUC manual.

The total allocator calculated in Column 7 of Figure 2 is used to allocate fixed production plant-related costs to the classes. For example, based upon this methodology, the residential class should be allocated 51.55% of the total fixed production plant-related costs, while the LGS/SPS and LPS classes should be allocated 29.16% and 7.63% of these costs respectively.

Q. What insights can be gained from Figure 2 above?

A. As the Commission recognized in its 2010 Ameren decision, the class average and excess demand calculations provide important insights regarding the relative variability in each class's load profile. Classes with higher variability use the system less efficiently, are generally weather sensitive and cause demand on the system to hit peaks. From a relative standpoint, classes with excess demand percentage shares (Column 6 in Figure 2) that exceed their respective average demand percentage shares (Column 5 in Figure 2) have higher variability in their load profile such as the residential class. Conversely, classes with average demand percentage shares higher than their excess demand shares have lesser variability and utilize the system more efficiently such as the Large General Service, Small Power Service and Large Power Service classes.

Figures 3(a) and 3(b) demonstrate the difference in variability in both monthly coincident and non-coincident peak demand for two classes, namely, residential and

LPS classes respectively. The graphs show the higher variability or "peakiness" in residential peak demands compared to the LPS class, which is relatively flatter.

Figure 3 (a): Residential and LPS Class Monthly CP Demands

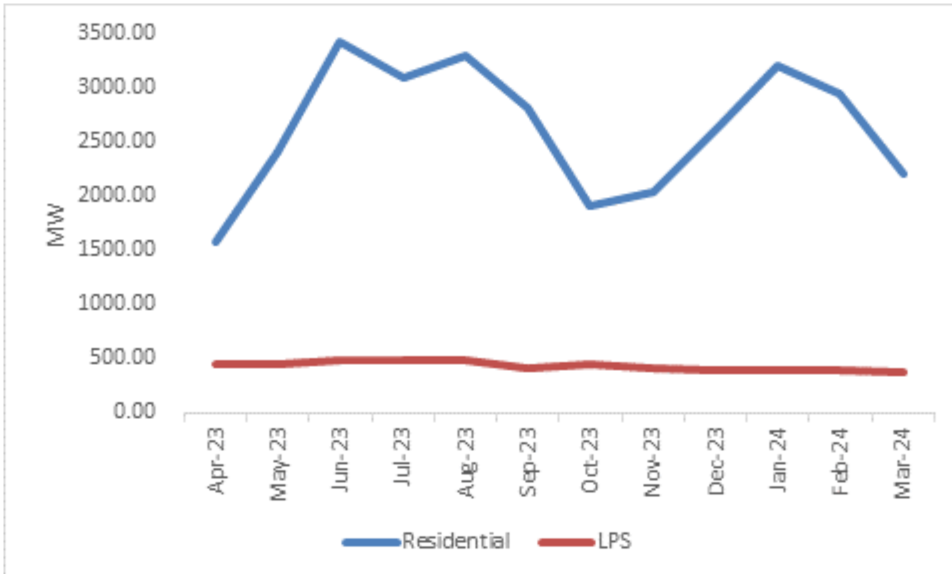
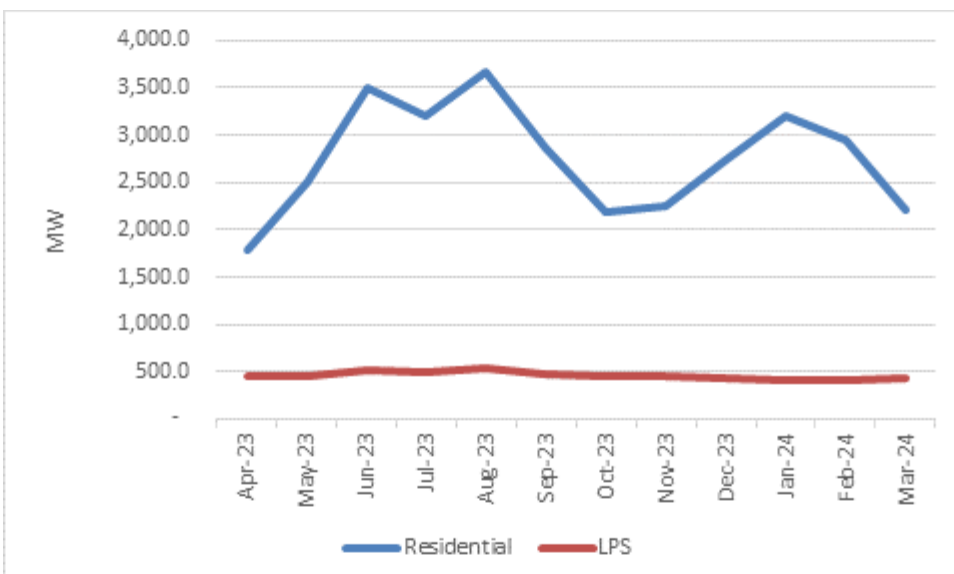


Figure 3 (b): Residential and LPS Class Monthly NCP Demands



Q. Did you use the Company's COSS model to calculate the results using MECG's A&E 4NCP allocator?

A. Yes, I did. I changed the Company's A&E allocator in the Company's COSS model to MECG's A&E 4NCP allocator. I did not make any other changes.

Q. Please explain how the COSS results are shown.

A. Upon completion of the class cost of service study, the net income for each class (revenues less expenses) is divided by the rate base dedicated to serving that class to calculate the rate of return earned at present rates. To the extent that a class rate of return is greater than the system return, then the revenues recovered from the class are more than the costs to serve that class. Similarly, to the extent that a class rate of return is lower than the system return, then the revenues recovered from the class are less than the costs to serve this class. For instance, as reflected in Figure 4, Ameren Missouri's overall earned return under the class cost of service study is 5.01% at present rates. As can be observed from MECG's COSS results (which are substantially similar to the Company's results), the Company earned a below system average return from the Residential (3.59%) and Lighting (2.51%)[3] classes, slightly above system average return from the SGS class (5.46%), and above average for the LGS/SPS class (7.28%) and LPS (8.82%) classes respectively.

Q. Are the COSS results using Ameren Missouri's A&E 4CP method and your A&E 4NCP method generally consistent?

A. Yes, they are. I compared the earned rate of return ("ROR") and the relative ROR[4] and found that the results are substantially similar. Classes with the relative rate of return below 1 are currently paying rates that are below the cost to serve those classes such as

[3] Company and customer owned combined.
[4] Relative ROR is an index calculated as class ROR divided by system ROR.

the residential class. Conversely, Classes with the relative ROR above 1 are currently paying rates that are above the cost to serve those classes such as LGS, SPS and LPS respectively.

Figure 4: MECG v. Ameren Missouri's CCOSS Earned Rate of Return ("ROR") and Relative ROR by Class at Present Rates

	Ameren Missouri A&E 4NCP COSS		MECG A&E 4NCP COSS	
	Earned ROR	Relative ROR	Earned ROR	Relative ROR
Residential (RES)	3.67%	0.73	3.59%	0.72
Small General Service (SGS)	5.54%	1.10	5.46%	1.09
Large General Service (LGS) / Small Power Service (SI	7.12%	1.42	7.28%	1.45
Large Power Service (LPS)	8.41%	1.68	8.82%	1.76
Lighting (LTG)	2.51%	0.50	2.51%	0.50
Overall Ameren Missouri	5.01%	1.00	5.01%	1.00

Q. Which fixed production cost allocation method should be used in this case?

A. I recommend that the Commission adopt the A&E 4NCP allocator (and the related MECG COSS results), since this method is more consistent with the A&E methodology described in Section 393.1620.1 (1). That said, should the Commission decide to adopt the Company's production cost allocation in this case, MECG does not oppose, given the substantial similarity in results.

Q. Do you recommend any other changes to the COSS?

A. Not at this time. The MECG COSS or Ameren Missouri's COSS are reasonable, and the related results can be relied on, to guide revenue allocation. As discussed below, I used the MECG COSS results.

IV. REVENUE REQUIREMENT ALLOCATION

Q. What should be the primary guiding principle in establishing fair and reasonable rates?

A. A properly developed COSS is important to establishing fair and reasonable rates. It is used to determine revenue requirement for the Company and should be used as the primary guiding principle in allocating revenue requirement to classes and informing rate design. Also as discussed earlier in my testimony, such an approach fulfills the important goals of promoting equity among classes and encouraging economic efficiency. If revenues are allocated to classes and align closely with the class cost responsibility, equity is maintained because each class pays its fair share of costs. Further, if retail rates align with cost of service, they reflect accurate pricing signals that drive consumer behavior, which in turn results in more efficient use of the system and minimizes system costs.

Q. Can other factors be also considered?

A. Yes. Other factors such as gradualism and rate continuity may also be considered. At the same time, however, these factors should not be the dominating elements such that there is little to no movement towards cost responsibility. We must also weigh in the fairness consideration and not ignore the important aspect that when one class is not paying their full share, one or more classes are being asked to pay more than their cost responsibility.

Q. Do you rely on MECG's COSS results to make recommendations regarding revenue apportionment to classes?

A. Yes. I do. However, given that both the Company and MECG's results are substantially similar, my revenue allocation recommendation is also reasonable when compared to the Company's COSS results.

I draw the same conclusions from a policy perspective from both the Company's and MECG's COSS results. For instance, given that the residential and lighting classes earned ROR below Ameren Missouri's system ROR at present rates, these classes should receive above system average increases. All other classes such as the small general service, large general service, small primary service and large primary service earned RORs above the system ROR at present rates. Therefore, these classes should receive increases that are below the system average increase.

Q. What are the total revenue neutral adjustments needed by class to completely eliminate the cross subsidization at present rates in this case?

A. Figure 5 shows the derivation of the MECG COSS revenue neutral adjustments needed to align revenue responsibility with cost responsibility at present rates. Lines 1-16 show the various components that result in a jurisdictional ROR of 5.01% at present rates. Line 17 shows the ROR for each class at present rates. Lines 19 and 20 show the revenue neutral changes (in dollars and %) needed to class revenues in order to completely eliminate cross subsidization. That is, it shows the amount of increase or decrease required to have every class yield the same rate of return, before considering any overall change in revenues for the utility. Line 21 shows a 25% revenue neutral shift to yield the same ROR at present rates.

As can be observed, in order to eliminate any cross subsidization under present rates, significant revenue neutral changes would be necessary. For example, under present rates, the Residential would need a revenue neutral increase of 7.59% to base rate revenues in order to achieve cost based responsibility. The SGS, LGS and LP classes would need a 2.58%, 9.58% and 13.99% decrease respectively.

Figure 5: MECG COSS: Revenue Neutral Adjustments Needed for Equal ROR at Present Rates

LINE NO:		MISSOURI	RESIDENTIAL	SMALL GEN SERV	LARGE G.S. / SMALL PRIMAR	LARGE PRIMARY	LIGHTING
1	BASE REVENUE	$2,886,734	$1,458,541	$330,526	$835,778	$219,758	$42,131
2	OTHER REVENUE	$89,215	$49,456	$9,707	$23,137	$5,631	$1,284
3	LIGHTING REVENUE	$0	$0	$0	$0	$0	$0
4	SYSTEM, OFF-SYS SALES & DISP OF ALLOW	$647,543	$279,391	$68,121	$224,905	$73,033	$2,093
5	RATE REVENUE VARIANCE	$0	$0	$0	$0	$0	$0
6	TOTAL OPERATING REVENUE	$3,623,491	$1,787,387	$408,355	$1,083,819	$298,422	$45,508
7	TOTAL PROD, T&D, CUST, AND A&G EXP	$1,848,938	$905,476	$198,592	$561,243	$165,011	$18,616
8	TOTAL DEPR AND AMMORT EXPENSES	$974,090	$546,191	$111,065	$242,184	$56,721	$17,929
9	REAL ESTATE AND PROPERTY TAXES	$180,866	$102,126	$20,801	$44,233	$10,178	$3,528
10	INCOME TAXES	($103,928)	($57,742)	($11,892)	($26,193)	($5,993)	($2,109)
11	PAYROLL TAXES	$20,301	$11,370	$2,228	$5,090	$1,220	$393
12	FEDERAL EXCISE TAX	$0	$0	$0	$0	$0	$0
13	REVENUE TAXES	$0	$0	$0	$0	$0	$0
14	TOTAL OPERATING EXPENSES	$2,920,266	$1,507,419	$320,794	$826,558	$227,138	$38,357
15	NET OPERATING INCOME	$703,225	$279,968	$87,560	$257,262	$71,284	$7,151
16	TOTAL NET ORIGINAL COST RATE BASE	$14,023,355	$7,791,378	$1,604,575	$3,534,268	$808,604	$284,529
17	RATE OF RETURN	5.01%	3.59%	5.46%	7.28%	8.82%	2.51%
18	EQUAL ROR AT PRESENT RATES (5.01%)	$703,225	$390,712	$80,464	$177,232	$40,549	$14,268
19	REVENUE NEUTRAL SHIFT ($)	$0	$110,744	($7,096)	($80,030)	($30,735)	$7,117
20	REVENUE NEUTRAL SHIFT (%)		7.59%	-2.15%	-9.58%	-13.99%	16.89%
21	**25% REVENUE NEUTRAL SHIFT (%)**		**1.90%**	**-0.54%**	**-2.39%**	**-3.50%**	**4.22%**

Q. What is the Company's revenue allocation proposal?

A The Company proposes a 0.25% revenue neutral adjustment to the residential class. One-third of the associated revenue is used to decrease the SPS current normal base rate revenue requirement and two-thirds is used to decrease the LPS current normal base rate revenue requirement.

Q. Please comments on the Company's proposed approach.

A. While I appreciate the Company's effort to make the proposed revenue neutral adjustment, I believe larger revenue neutral adjustment changes are necessary in order to achieve a fairer outcome. The Company's proposal of a 0.25% revenue neutral increase to the residential class places more emphasis on tempering the rate impacts while largely ignoring the equity aspect. It does not seem fair to ask customers in other classes such as the LGS and SPS classes to continue an on-going practice of cross subsidizing other classes.[5] In my view, larger revenue neutral shifts are needed compared to the Company's proposal to address cross subsidization and restore fairness and equity to the various classes. I would also note that the Company has not explained why a revenue neutral shift is made to three select classes. A more systematic and objective approach guided by the COSS results is needed to make the revenue neutral shifts.

Q. What is your recommendation to the Commission?

A. My recommendation is to make a 25% revenue neutral shift to each class <u>prior to</u> applying an equal percent increase associated with the final revenue requirement increase. The 25% revenue neutral shifts by class and in terms of percentages are shown in Figure 5, Line 21. The recommended revenue neutral shifts would help in incorporating fairness systematically among classes while at the same time, a 25% revenue neutral shift recognizes that moderation is necessary and to not align 100% with the COSS results.

V. RATE DESIGN

Q. What are the main unit charge components of the LGS Rate?

A The main unit charges consist of customer charge, demand charges, energy charges and a low income charge. The demand and energy charges are seasonally differentiated. The energy charges reflect Hours Use structure and consist of three blocks for each season.

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[5] See MECG witness Steve Chriss' direct testimony in the last Ameren Missouri Case in docket ER-2022-0337, Exhibit 400, Table 1, page 8. In this Table, Mr. Chriss uses the Company's COSS results to show the substantial level of negative revenue neutral adjustments needed to be aligned with cost responsibility for the LGS and SPS classes since the 2007 rate case. For ease of reference, the Table is attached as Exhibit KM-1.

There is also an optional time of use energy charge or credit overlay with additional customer charges.

Q. What is the Company's revenue allocation to the LGS class?

A. The Company proposes a revenue increase of 15.5% increase for the LGS class, which raises the average $/kWh rates from $0.0814/kWh to $0.094/kWh. As discussed earlier, I do not support this increase for the LGS class. In the rate design discussion, however, I assume the same revenue requirement as the Company in order to demonstrate an apples-to-apples comparison.

Q. What is the Company's rate design proposal for the LGS class?

A The Company proposes an equal percent increase (15.5%) to the main elements of the rate such as customer, energy and demand charges. Respectively.

Q. What concerns do you have regarding the LGS rate?

A I am concerned that the demand charges are relatively low, which results in substantive over recovery from energy charges and under recovery from the demand charges as compared to the COSS results. According to the unbundled COSS results, 79% of the costs for the LGS and SPS classes are demand related. However, under current rates, only 14% is recovered from demand charges and 84% of the revenue requirements are recovered from energy charges. This mismatch sends economically inefficient and faulty pricing signals.

Aside from the disparity and inconsistency with the COSS results, the Company's proposed increases in the current rate case are predominantly fixed costs and associated with capital investment and depreciation expenses. Fixed costs do not vary with energy consumption and should be recovered from demand charges.

Therefore, the primary drivers in the case support higher increases to demand charges versus energy charges.

Q. What is your recommendation?

A. I recommend the following:

- Increase the customer charges, on and off peak adjusters as proposed by the Company.
- Increase the summer and winter demand charges by 150%.
- Increase energy charges to recover the remaining revenue requirement by an equal percentage.

Q. What are the main unit charge components of the SPS Rate?

A. Similar to the LGS rate, the main unit charges consist of customer charge, demand charges, energy charges and a low income charge. The SPS rate also includes a reactive charge. The demand and energy charges are seasonally differentiated. The energy charges reflect Hours Use structure and consist of three blocks for each season. There is also an optional time of use energy charge or credit overlay with additional customer charges.

Q. What is the Company's revenue allocation to the SPS class?

A. The Company proposes a revenue increase of 14.94% increase for the SPS class, which raises the average $/kWh rates from $0.0705/kWh to $0.081/kWh. As discussed earlier, I do not support this increase for the SPS class. In the rate design discussion, however, I assume the same revenue requirement as the Company in order to demonstrate an apples-to-apples comparison.

Q. What is the Company's rate design proposal for the SPS class?

A The Company proposes an equal percent increase (14.94%) to the main elements of the rate such as customer, energy and demand charges. Respectively.

Q. What concerns do you have regarding the SPS rate?

A I have the same concerns as I discussed regarding the LGS rate earlier. The demand charges are relatively low, which results in substantive over recovery from energy charges and under recovery from the demand charges as compared to the COSS results. According to the unbundled COSS results, 79% of the costs for the LGS and SPS classes are demand related. However, under current rates, only 10% is recovered from demand charges and 89% of the revenue requirements are recovered from energy charges.

Aside from the disparity and inconsistency with the COSS results, the Company's proposed increases in the current rate case are predominantly fixed costs and associated with capital investment and depreciation expenses. Fixed costs do not vary with energy consumption and should be recovered from demand charges. Therefore, the primary drivers in the case support higher increases to demand charges versus energy charges.

Q. What is your recommendation?

A. Similar to the LGS class, I recommend the following for the SPS class:

- Increase the customer charges, on and off peak adjusters, reactive charges and Rider B adjustments as proposed by the Company.
- Increase the summer and winter demand charges by 150%; and
- Increase energy charges to recover the remaining revenue requirement by an equal percentage.

Q. Do you have any other comments regarding the LGS and SPS rates?

A. Yes. I understand that non-residential rate design is being investigated in another docket as noted by Company witness Mr. Nicholas Bowden on page 32 of his direct testimony. I recommend that the Company provide a progress report as well as a timeline by when it intends to propose alternative or optional rate design proposals applicable to non-residential classes.

Q. Do you have any comments regarding the Company's proposal regarding the LPS rates?

A. Yes. For reasons identified earlier and similar to LGS and SPS, I do not support the Company's proposed 14.22% increase to this class.

From a rate design perspective and compared to the LGS and SPS rates, the LPS rate design appropriately recovers a substantive portion from demand charges and is more functionally aligned with the COSS results.[6] Given the current rate design charges, I do not oppose an equal percent increase to the demand, customer and energy charges.

Q. Does this conclude your direct testimony?

A Yes.

[6] The revenue requirement recovery from demand charges in LPS rates is 44%. A current demand charge of $21.45/KW-month provides an appropriate pricing signal that capacity is expensive.

Exhibit KM -1: Excerpt Table to show Company's calculated Revenue Neutral Shifts Required to Move LGS/SPS to Cost of Service in Past Ameren Rate Cases

Table 1. Summary of Revenue Changes, Per Ameren Cost of Service Study Results, Required to Move LGS and SP to Cost of Service in Previous Ameren Rate Cases.

Rate Case	Revenue Change Required to Move LGS/SP to Cost of Service	
	($000)	(%)
ER-2007-0002		
LGS	($43,441)	-10.2
SP	($8,148)	-4.5
ER-2008-0318 (LGS & SP)	($47,863)	-7.66
ER-2010-0036 (LGS & SP)	($64,785)	-9.74
ER-2011-0028 (LGS & SP)	($63,653)	-8.94
ER-2012-0166 (LGS & SP)	($59,937)	-7.99
ER-2014-0258 (LGS & SP)	($68,705)	-8.54
ER-2016-0179 (LGS & SP)	($26,675)	-3.40
ER-2019-0335 (LGS & SP)	($84,130)	-10.44
ER-2021-0240 (LGS & SP)	($66,501)	-9.14
Present Case	($58,749)	-7.42

Source: Ameren's ECCOSS Results, SCH 1. For the present case, provided in response to MECG_1-MECG_1_3.

Source: Direct Testimony, Steve W. Chriss (MECG Witness in Docket ER-2022-0337, Table 1, page 8).