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-2024-0189
Date Testimony Prepared:	July 12, 2024

BEFORE THE PUBLIC SERVICE
COMMISSION OF THE STATE OF MISSOURI

In the Matter of Evergy Missouri West, Inc. d/b/a Every Missouri West's Request for Authority to Implement A General Rate Case Increase for Electric Service	**)** **)** **)** **)** **)**	**File No. ER-2024-0189**

Direct Testimony and Schedules of

Kavita Maini

On behalf of

MIDWEST ENERGY CONSUMERS GROUP

July 12, 2024

Protecting Your Bottom Line

KM ENERGY CONSULTING, LLC

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Missouri West, Inc. d/b/a	)	
Every Missouri West's Request for	)	
Authority to Implement A General Rate	)	Case No. ER-2024-0189
Case Increase for Electric Service	)	

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-2024-0189.

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

**BEFORE THE PUBLIC SERVICE
COMMISSION OF THE STATE OF MISSOURI**

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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 Evergy

Missouri West, Inc. ("EMW" or "Company") on its Large General Service ("LGS") and Large Power 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, EMW proposes an approximately $109 million increase in revenue requirement or 14% increase on a systemwide basis. For this increase, EMW proposes a 14.3% increase to the LPS class and 11.5% increase to the LGS class respectively while the Company's own cost of service study supports much lower increases at 6% for the LPS class or no increase for the LGS class. The large commercial and industrial customers members served by EMW 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 LPS and LGS 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: LPS and LGS Rate Design

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 method and I support this method in this case.

c) The A&E approach considers the load profile of customer classes by incorporating the class's maximum demands, load factor and average energy use. Therefore, the A&E approach is a reasonable method to use in this case. In fact, the A&E method is used by Ameren, Liberty-Empire and Evergy respectively.

d) While the Company uses class coincident peak contribution to the four summer peaks in calculating the excess demand portion, 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 EMW's COSS.

f) The Company needs to further refine the classification of its primary distribution system into single and three-phase circuits in order to properly direct costs to primary and secondary voltage customers. Failure to do so results in allocating single phase circuit related costs to primary customers who are not served by single-phase configuration. I recommend that in rebuttal testimony, the Company should identify the steps and effort needed to get access to the data needed and the associated timeline to delineate between single phase and three phase distribution configurations to properly allocate costs to secondary and primary customers.

g) The Company's fuel cost allocation can more closely follow cost causation by following an allocation method that recognizes the class load and fuel cost hourly variations. In rebuttal testimony, the Company should explain if it has the class data necessary to calculate the E8760 allocator and associated timeline to get this allocator incorporated in its COSS.

Section IV: Revenue Requirement Allocation

a) While the Company's and MECG's COSS could be refined further, the current methodology is reasonable and the COSS results can be relied upon, 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 EV classes are paying rates that are substantially below cost responsibility. All other classes are paying rates above their class cost responsibility.

d) While a much larger revenue neutral adjustment is justifiable based on the COSS results, given the double digit proposed increase of approximately 14%, I employed substantial moderation while also making a concerted effort to make revenue neutral shifts in my revenue allocation recommendation. I recommend that if the systemwide rate increase is lower than 10%, the multipliers should change to accommodate additional revenue neutral shifts and make further movement towards cost responsibility. The lower the Company's jurisdictional rate increase, the more it is reasonable to focus on larger revenue neutral shifts to get class revenue responsibility closer to cost responsibility.

Section V: LPS/LGS Rate Design

a) LPS and LGS Rates: The Company proposes to align the facility and customer charges based on its COSS results. With regards to changes in other charges, the remaining revenue requirement is proposed to be collected via demand and energy charges with extra weighting given to demand charges in recognition of the historical fixed/variable cost disparity between energy and demand charges.

Given the limitations of the Company's COSS regarding the classification of certain distribution plant, which may not be properly allocating costs to the LPS and LGS classes and sub classes respectively, I recommend lower increases to the facility charges compared to the Company's proposal. In addition, I recommend retaining the existing customer charge, retaining the same percentage increase to energy charges as proposed by the Company and increasing the billed demand charge to recover the remaining revenue requirement.

b) With regards to changes in future cases, I support the Company's view that we need to consider rate impacts and transition towards time variant rates by addressing the annual base demand element as a first step as it relates to the LGS and LPS rates. In this regard, I recommend that the Company work collaboratively with MECG to develop and refine its proposed approaches before introducing these proposals in a future case.

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. Given this, 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. As mentioned, the Commission expressly recognized this fact in 2014 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.

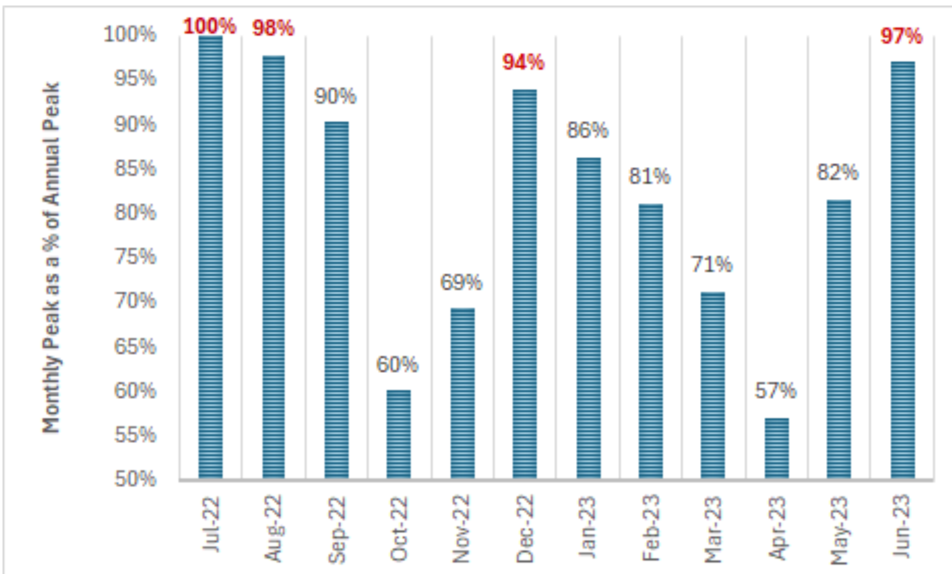
Q. What should be considered in determining the appropriate allocator for fixed production plant-related costs?

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

Q. Did you analyze EMW'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 EMW's system maximum demand occurs in the summer with the highest peak occurring in July, followed by the second and third highest peaks also occurring in the summer in June and August respectively. The fourth highest peak occurred in December. 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 fourth months. Further, as I discuss later in this section, utilizing the non-coincident peaks for the four months with the highest system peak load 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 EMW'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 EMW's current case, class contributions coincident with the four highest demands of June through August and December 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 (8,760 for a non-leap 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 simply 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 EMW, utilizing the class contribution to the Company's four highest system demands 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. The Company uses the A&E method for allocating fixed production costs.[3] Ms. Marisol Miller testifies that after considerable efforts to determine the most appropriate production allocation methodology in prior rate cases, the Company intends to continue to utilize the A&E method. EMW has been utilizing the A&E method since the 2018 rate case (docket ER-2018-0146). In the 2018 case, the Company evaluated a number of methodologies and chose the A&E method in large part to acknowledge and appropriately recognize that industrial facilities with relatively high load factors efficiently use the system and to develop industrial rates that are competitive with neighboring utilities.[4]

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, as the Commission is aware from the recent rate cases, the A&E methodology has been adopted by Ameren, Empire and Evergy respectively.

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

[3] The A&E allocator is also used to allocate transmission costs, which is appropriate for all of the same cost causative reasons as identified in my testimony for fixed production plant.
[4] See Mr. Thomas Sullivan's direct testimony in docket ER-2018-0145.

A The Company's A&E approach relies on class contribution coincident to the four summer peak demands to calculate the excess demand. The method prescribed in the NARUC manual for the A&E method, however, appears to encourage the use of non-coincident peak demands (NCP) and is also a more common approach used by other Missouri utilities. Further, the Test Year system peak data shows that the four highest demands are in June, July, August and December and therefore, not all four summer months.

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 December 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	1,149.86	4,011,929	457.98	691.88	45.23%	69.608%	**57.09%**
Small General Service	290.30	1,391,822	158.88	131.41	15.69%	13.221%	**14.49%**
Large General Service	240.09	1,315,137	150.13	89.96	14.83%	9.050%	**12.02%**
Large Power Service	315.58	2,107,294	240.56	75.02	23.76%	7.548%	**15.87%**
Lighting	10.34	43,778	5.00	5.34	0.49%	0.537%	**0.51%**
EV	0.41	509	0.06	0.35	0.01%	0.035%	**0.02%**
Total	2,006.58	8,870,469	1,013	994	100.00%	100.000%	**100.000%**

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) by class and Column 3 converts this annual energy (MWh) to average demand (MW) by dividing the annual energy usage by 8,760 (number of hours in the test year). 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 EMW's system average demand. So, for instance the residential average demand percentage share is 457.98 MW divided by the total of 1013 MW or 45.23%. 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 691.88 MW divided by 994 MW or 69.61%. 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 (51.36%) and (b) weighting the class excess as a proportion to the total excess demand (Column 6) by 1 minus the system load factor (48.64%). This method is consistent with the NARUC manual.

The total allocator calculated in Column 7 of Figure 3 is used to allocate fixed production plant-related costs to the classes. For example, based upon this methodology, the residential class should be allocated 57.09% of the total fixed production plant-related costs, while the LPS and LGS classes should be allocated 15.87% and 12.02% 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 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

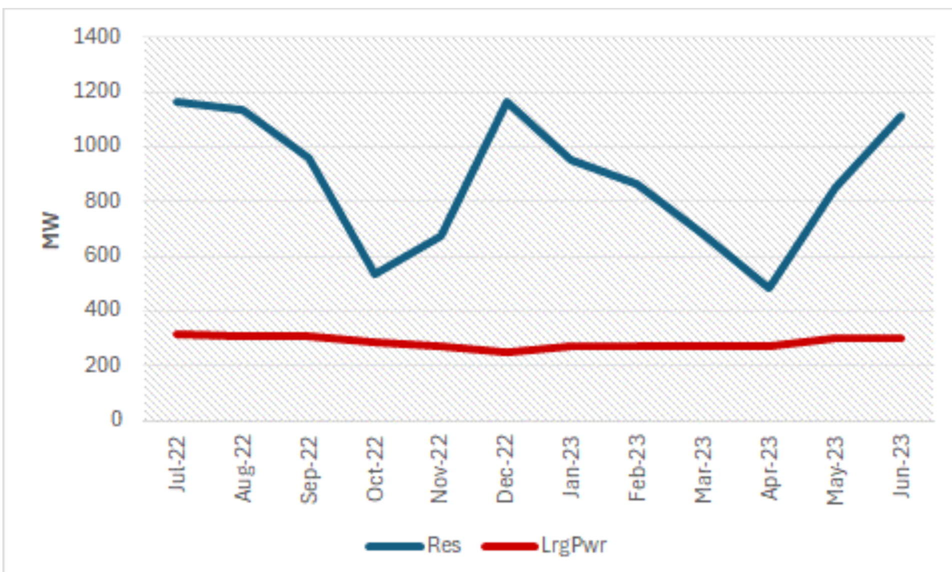
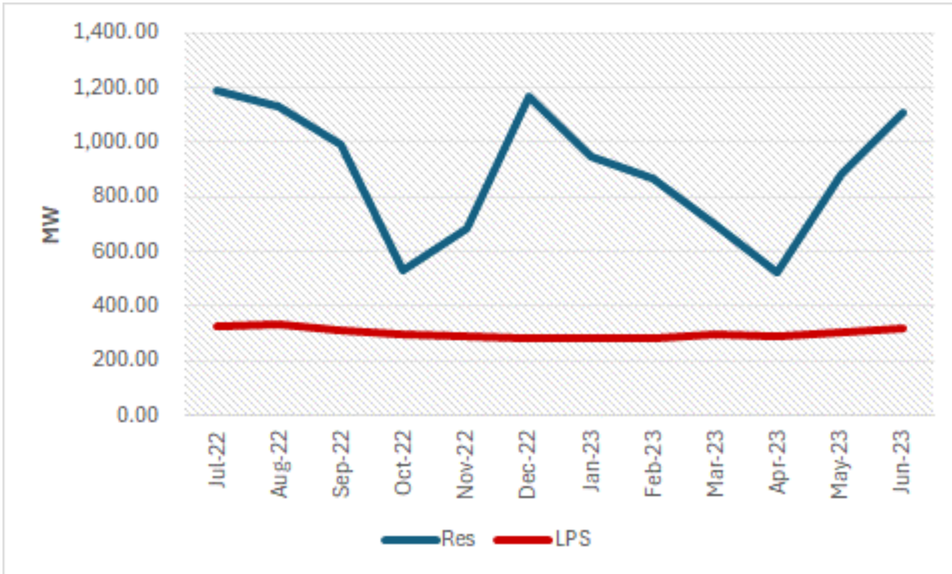


Figure 3 (b): Residential and LPS Class Monthly NCP Demands



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

A. Yes, I did. I changed the Company's A&E allocator in the Company's COSS model from the A&E 4CP to MECG's A&E 4NCP allocator.

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, EMW's overall earned return under the class cost of service study is 4.64% at present rates. As can be observed from MECG's COSS results (which are substantially similar to the Company's results), EMW earned a below system average return from the residential class (2.74%) and above system average return from the small general service (9.01%), lighting (8.93%), large general service (7.44%) and large power classes (5.94%) respectively. The Company earned a negative return from the EV class, meaning that this class's revenue was not enough to cover its expenses.

Q. Are the COSS results using EMW'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[5] 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 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 small general service, lighting LGS and LPS respectively. Figure 5 shows a summary of the COSS results utilizing MECG's A&E 4NCP method at present rates.

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

	EMW COSS RESULTS (A&E 4CP)		MECG COSS RESULTS (A&E 4NCP)	
Class	Earned ROR	Relative ROR	Earned ROR	Relative ROR
Residential	2.64%	0.57	2.74%	0.59
Small General Service	9.29%	2.00	9.01%	1.94
Large General Service	7.58%	1.63	7.44%	1.60
Large Power Service	5.94%	1.28	5.94%	1.28
Lighting	10.46%	2.26	8.93%	1.93
EV	-59.93%	-12.93	-52.08%	-11.23
EMW	**4.64%**	**1.00**	**4.64%**	**1.00**

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

[5] Relative ROR is an index calculated as class ROR divided by system ROR.

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 the NARUC manual and 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.

D. COSS: Fuel Production Costs

Q. How were the fuel costs associated with the production plant allocated in EMW's COSS study?

A. Ms. Miller indicates on page 17 of her direct testimony that fuel costs were allocated using a monthly kWh allocator.

Q. What are your observations about the use of a flat energy allocator?

A. This allocator does not recognize hourly energy cost and load variations. Fuel costs vary by the hour and are typically higher in the week daytime hours compared to night-time and weekend hours. Other utilities utilize an E8760 allocator to allocate fuel costs to appropriately recognize the hourly customer class and fuel cost variations. I recommend that in rebuttal testimony, the Company identify if it has the class and fuel cost data necessary to calculate the E8760 allocator and associated timeline to get this allocator incorporated in its COSS.

E. COSS: Fixed Distribution Plant Related Costs

Q. What are fixed distribution plant related costs?

A. Fixed distribution plant related costs are associated with infrastructure that connects customers with the transmission grid and is built to provide access to electricity that has been generated and transmitted.

Q. What method has the Company used to classify certain fixed distribution plant related costs booked in FERC accounts 364 through 368, into customer and demand related components?

A. Costs booked in FERC accounts 364 through 368 are associated with certain distribution plant related fixed costs as follows:

- Account 364 – Poles, Towers and Fixtures
- Account 365 – Overhead Conductors and Devices
- Account 366, 367 – Underground Conduits, Conductors and Devices
- Account 368 – Line Transformers

Similar to past cases, the Company has utilized the minimum size or system method to classify distribution plant related costs in the above mentioned FERC accounts as customer and demand related.

In this case, the Company has introduced a new primary-secondary allocator that further splits the costs classified as demand-related into primary and secondary voltage. As noted in Ms. Miller's testimony on page 18, this allocator is based on dollar-weighted line miles for both overhead and underground conductor.

Q. What are your observations about the Company's methodology to classify and allocate the distribution costs booked in FERC accounts 364 through 368?

A. The minimum distribution approach is a long established approach, widely used by utilities and recognized in the NARUC manual. I support this approach as it recognizes the basic premise that that the distribution system exists to serve a dual purpose: 1) being capable of delivering service to customers' residences or businesses (customer costs), and 2) ensuring that the distribution system is large enough to provide reliable service (demand costs).

As it relates to the Company's specific assumptions used to ascertain the minimum system costs, I am in the process of evaluating and have issued discovery questions. I may have additional feedback in rebuttal testimony.

While the Company has made efforts to further split the demand related costs into primary and secondary voltage, further refinements are necessary to ensure that customers served under primary voltage are not allocated a disproportionate share of the costs by failing to recognize the single phase and three phase delineation associated with the primary distribution system. I discuss this issue further below.

Q. Why should the single phases costs be separated out from the three-phase circuit configuration within the primary distribution system?

A. To properly assign costs to those customer classes and voltages that utilize the specific configurations. Feeders originate from substation in three-phase configuration and is distributed via separate conductors for each phase. The Company's primary distribution system consists of single-phase and three-phase circuit configurations. While the costs of these configurations are included in FERC accounts 364 through 367, the Company does not currently differentiate the system costs based on single and three-phased configurations as shown in response to MECG 2.4 (see Attachment A). As a result the COSS allocates costs related to single phase primary distribution circuits to both primary voltage and secondary voltage customers, which does not follow cost causation. Failure to separate out costs associated with single versus three phase distribution circuits results in over allocating the costs to primary voltage customers due to the following:

1. The Company has identified that through its Mapping System that 61.4% of the Company total miles of circuits are single phase and 38.6% are three-phase (including the two-phase configuration which is used to provide a form of three-phase service). As noted by the Company, the single phase circuits are not utilized to provide service to primary customers.[6] Therefore, the single phase circuit related costs associated with 61.4% of the Company's total miles of circuits should only be allocated to secondary voltage customers. None of these costs should be allocated to primary voltage customers.
2. As it relates to the three-phase related configuration, the costs associated with this configuration should be allocated to secondary and primary voltage customers because as noted by the Company, the secondary voltage customers are also served by three-phased circuit configuration.[7]

I am particularly concerned regarding the over allocation to primary customers (and therefore, related classes such as LPS) in this case because the Company has requested $56 million in revenue requirement associated with new infrastructure related primarily to distribution equipment, which includes overhead and underground conductors and associated infrastructure that incorporates the single phase and three-phase circuits.

Q. Do you know of other utilities that have delineated between single phase and three phase circuits related costs within their primary distribution system?

A. Yes, I know of at least two examples of major utilities that have separated out the single phase versus three phase costs and allocated them appropriately:

[6] See response to MECG 2.4 b.
[7] See response to MECG 2.4 d.

- Xcel Energy in Minnesota introduced this delineation in 2013 in docket E002/GR-13-868 and has been including it since that time.
- We Energies in Wisconsin introduced this delineation in 2014 in docket 05-UR-107 and has incorporated it in their COSS since that time.

Q. Based on the above observations, what is your recommended approach to the Company to address this issue?

A. Instead of identifying a primary and secondary allocator for costs classified as demand related to be split into primary and secondar voltage service levels, I recommend three subcategories:

1. Single-phase primary costs: These costs should be allocated to only secondary voltage customers since single-phase circuits are only used to provide service to secondary customers and not used to provide service to primary voltage customers.
2. Three-phase primary costs: These costs should be allocated to primary and secondary voltage customers to follow cost causation as discussed above.
3. Secondary costs. These costs should be allocated to secondary voltage customers only.

Based on the Company's discovery response to MECG 2.4 (Attachment 1), the Company's systems do not currently differentiate between single and multi-phase configuration. I recommend that the Company explain in rebuttal testimony the steps and effort needed to get access to the data needed to conduct the separation of costs and the associated timeline.

Q. Please summarize your recommendations regarding COSS.

A. The summary of my recommendations is as follows:

Fixed Production Cost Allocator: 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 the NARUC manual and 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.

Fuel Cost Allocation: In rebuttal testimony, the Company should identify if it has the class data necessary to calculate the E8760 allocator and associated timeline to get this allocator incorporated in its COSS.

Fixed Distribution Plant related to FERC Accounts 364-367: I recommend that in rebuttal testimony, the Company should identify the steps and effort needed to get access to the data needed and the associated timeline to delineate between single phase and three phase distribution configurations to properly allocate costs to secondary and primary customers

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. While both the Company's and MECG's COSS could be refined further to address the issues explained in Section III, the current methodology is reasonable and the COSS results can be relied upon, as guidance for revenue apportionment.

As noted earlier, MECG's COSS results are substantially similar to the Company's COSS results and I draw the same conclusions from a policy perspective from both the COSS results. For instance, given that the residential and EV classes have ROR below EMW'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, large power service and lighting classes have 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 through 5 show the results for each class at present rates and the related ROR and relative ROR. Line 8 shows the income required to achieve equal ROR and Line 9 shows the difference between the income required to achieve equal ROR (Line 8) and income that produces the current ROR (Line 3). Lines 10 and 11 show the revenue neutral changes (in both nominal 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 12 (a) and 12 (b) shows 25% and 50% revenue neutral shifts 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 10.4% to base rate revenues in order to achieve cost based responsibility. The SGS, LGS and LP classes would need a 17.8%, 11.4% and 4.9% decrease respectively.

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

LINE NO:		MO West Retail	Residential	Small General Service	Large General Service	Large Power Service	Electric Vehicle	Lighting
	REVENUE REQUIREMENT SUMMARY							
1	Test Year Revenue	$778,520,014	$411,065,976	$127,764,174	$94,688,002	$122,364,301	$83,305	$13,661,095
	RETURN AT PRESENT RATES							
2	Rate Base	$ 2,830,914,746	$ 1,713,682,941	$394,681,313	$294,026,969	$347,890,345	$1,595,232	$61,134,518
3	Net Operating Income at Present Rates	$131,252,484	$ 46,894,762	$ 35,574,262	$ 21,867,850	$ 20,679,172	$ (830,727)	$ 5,456,551
4	Rate of Return at Present Rates	**4.64%**	**2.74%**	**9.01%**	**7.44%**	**5.94%**	**-52.08%**	**8.93%**
5	Relative Rate of Return	1.00	0.59	1.94	1.60	1.28	(11.23)	1.93
	EQUALIZED RATE OF RETURN AT PRESENT RATES							
	Rate Base	$ 2,830,914,746	$ 1,713,682,941	$ 394,681,313	$ 294,026,969	$ 347,890,345	$ 1,595,232	$ 61,134,518
6	Equalized Rate of Return	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%
7	Relative Rate of Return	1.00	1.00	1.00	1.00	1.00	1.00	1.00
8	Return Required @ Equalized Rate of Return at Present Rates	$131,252,484	$79,453,167	$18,298,998	$13,632,261	$16,129,582	$73,961	$2,834,440
9	Difference in Income at Equal ROR at Present Rates	$0	$32,558,405	($17,275,264)	($8,235,588)	($4,549,589)	$904,689	($2,622,111)
10	Revenue Neutral Change to attain Equal ROR at Present Rates	$0	$42,752,116	($22,683,977)	($10,814,069)	($5,974,020)	$1,187,938	($3,443,068)
11	Revenue Neutral % Change to attain Equal ROR at Present Rates	0.0%	10.4%	-17.8%	-11.4%	-4.9%	1426.0%	-25.2%
12 (a)	25% Revenue Neutral Change @ Equal ROR at Present Rates	0.0%	2.6%	-4.4%	-2.9%	-1.2%	356.5%	-6.3%
12 (b)	50% Revenue Neutral Change @ Equal ROR at Present Rates	0.0%	5.2%	-8.9%	-5.7%	-2.4%	713.0%	-12.6%

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

A The Company proposes to apply certain multipliers to the average system increase in order to move classes closer to cost. Specifically, the Company proposes the following increases for each class for a system average increase of 13.99% (excluding special contracts):

- Apply a 16.59% increase to the residential and EV classes, which uses approximately 116% of the jurisdictional rate increase as the multiplier.
- Apply 15.05% to the LPS class which uses approximately100% of the jurisdictional rate increase as the multiplier.
- Apply a13.03% to the LPS class which uses approximately 80% of the jurisdictional rate increase as the multiplier.
- Apply 8.84% to the SGS class which uses approximately 60% of the jurisdictional rate increase as the multiplier. and

  Apply 8.65% to the lighting class which uses approximately 60% of the jurisdictional rate increase as the multiplier.

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

A. Given an average double digit jurisdictional increase of 13.99%, I am generally supportive of the Company's method to gradually moving class revenue responsibility towards cost responsibility. With a proposed double digit increase, it is not unreasonable to moderate the impact to certain classes and gradually move towards cost responsibility. However, I have an alternative recommendation for revenue apportionment to classes which amongst other factors, considers that the LPS class should not end up receiving an above average increase because this class earned an above average return under present rates.[8]

Q. What is your recommendation to the Commission?

A. My recommendation is provided in Figure 6 below. In this Figure, I show the COSS multipliers for the Company and MECG (last two columns). As can be observed in comparing with COSS based multipliers, both the Company and MECG applied significant rate moderation in recommending the revenue apportionment to classes.

Figure 6: EMW and MECG Multiplier Comparisons

	COSS Multipliers (Class Increase/ System Increase)			Multiplier Percent of Jurisdictional Increase	
	EMW	MECG		EMW	MECG
Residential	194%	189%		116%	117%
Small General Service	-49%	-42%		60%	70%
Large General Service	0%	4%		80%	77%
Large Power Service	43%	43%		100%	87%
EV	10111%	10721%		116%	117%
Lighting	-114%	-57%		60%	70%

Aside from moderating the impacts, my recommendation is similar to the Company's proposal in the following ways:

- First, out of all the classes, the residential and EV classes are subject to the highest and same multipliers because the COSS results show that at present rates, these two classes have relative RORs which are less than 1 or negative (see Figure 5, line 5).

[8] It should also be noted that the LGS and LPS are the two classes that includes primary customers which are over allocated certain distribution costs as discussed in Section III.

- Second, out of all the classes, the SGS and lighting classes are subject to the lowest and same multiplier because the relative RORs are the highest and close to one another at 1.93 and 1.94 respectively.

My recommendation departs from the Company's proposal with regards to the LPS class. I prescribe a lower than 100% multiplier to the LPS to recognize the above average return (or higher than 1 ROR) at present rates. I would also note that my revenue allocation recommendation is generally close to a 25% revenue neutral shift for most classes as shown in Figure 7 while remaining consistent with the application of the same class multiplier between certain classes based on relative ROR considerations at present rates.

Figure 7: MECG's COSS 25% Revenue Neutral Shift under Present Rates versus Revenue Neutral Shift Included in MECG Revenue Allocation Recommendation

	25% Revenue Neutral Shift from MECG COSS	Revenue Neutral Shift included in MECG Revenue Allocation
Residential	2.6%	2.7%
Small General Service	-4.4%	-4.1%
Large General Service	-2.9%	-2.9%
Large Power Service	-1.2%	-1.6%
EV	356.5%	2.6%
Lighting	-6.3%	-4.1%

With regards to the revenue requirement increase, the MECG multiplier recommendations shown in the last column in Figure 6 would be reasonable to apply for system wide increases of 10% and above. If the systemwide rate increase is lower than 10%, the multipliers should change to accommodate additional revenue neutral shifts and make further movement towards cost responsibility. The lower the jurisdictional rate increase, the more it is reasonable to focus on larger revenue neutral shifts to get class revenue responsibility closer to cost responsibility.

V. RATE DESIGN

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

A The main unit charges consist of facilities charge, customer charge, demand and energy charges. The demand and energy charges are seasonally differentiated. Further, the demand charge includes base billing demand charges for the summer and winter and seasonal demand charges for the summer only. The energy charges reflect Hours Use structure and consist of three blocks for seasonal and energy charges respectively. As more energy is consumed, the rates are lower, which is implicitly accounting for higher use of energy in the off-peak hours. Figure 8 shows the existing charges for the LPS at the secondary voltage service level. The rate schedule also includes service at the primary, sub transmission and transmission voltage service level.

Figure 8: LPS Rate at Secondary Voltage Service Level

Demand Charge	Summer	Winter
Base Billing Demand	$10.788	$5.618
Seasonal Billing Demand	$10.788	
Base Energy Charges		
First 180 Hours of Use per month	$0.05445	$0.05083
Next 180 Hours of Use per month	$0.04287	$0.03999
Over 360 Hours of Use per month	$0.03759	$0.03507
Seasonal Energy Charges		
First 180 Hours of Use per month	$0.05445	$0.03274
Next 180 Hours of Use per month	$0.04287	$0.03274
Over 360 Hours of Use per month	$0.03759	$0.03274
Customer Charge per Month	$675.46	
Facilities Charge ($/KW-Month)	$3.223	

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

A. The Company proposes a revenue increase of 15.05% for a systemwide increase of 13.99%. As discussed earlier, I do not support this increase for the LPS 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 LPS class?

A The Company proposes to align the facility and customer charges based on its COSS results. With regards to changes in other charges, the remaining revenue requirement is collected via demand and energy charges with extra weighting given to demand charges "in recognition of the historical fixed/variable cost disparity between energy and demand charges."[9]

Q. What elements do you support regarding the Company's proposal?

A I support the Company's proposal to allocate higher cost increases to demand charges versus energy charges. The higher cost recovery from fixed charges makes sense since over 95% of the revenue requirement increase is associated with increases in fixed costs.

Q. What concerns do you have regarding the Company's rate design proposal?

A. The Company proposes to increase the facility charges by 69%, 63% and 129% for the LPS secondary, primary and substation classes respectively. Aside from the concern about the large percentage increases impacting gradualism principles, I also do not feel comfortable in completely relying on the COSS results to increase the facility charges this significantly due to the issues regarding the classification and allocation of certain

[9] See Ms. Miller's direct testimony at page 30.

distribution plant related costs which may not be properly allocating costs to the LPS class and sub classes.

Q. What do you recommend?

A. Assuming the same revenue requirement allocation as proposed by the Company, my recommendation is as follows:

1. Increase facility charges by no more than 1.49 times the existing rate for secondary and primary voltage service levels.[10]
2. Retain the existing customer charge.
3. Retain the same percentage increase to energy charges as proposed by the Company.
4. Increase the billed demand charge to recover the remaining revenue requirement.

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

A The main unit charges consist of facilities charge, customer charge, demand and energy charges. The LGS rate design is similar to the LPS rate design and consists of the same components as described earlier for the LPS rate. Figure 9 shows the current charges. The difference is in the charges. The demand charges for the LGS class are lower than $1/KW-month which means substantial under-recovery of fixed costs through demand charges and over-recovery through energy charges. Figure 9 shows the existing charges for the LGS at the secondary voltage service level. The rate schedule also includes service at the primary voltage service level.

[10] For the substation level, the facility charge should be no more than half the proposed rate. At present, there is no facility charge.

Figure 9: LGS Rate at Secondary Voltage Service Level

Demand Charge	Summer	Winter
Base Billing Demand	$0.906	$0.61
Seasonal Billing Demand	$0.906	
Base Energy Charges		
First 180 Hours of Use per month	$0.08973	$0.06836
Next 180 Hours of Use per month	$0.06790	$0.06266
Over 360 Hours of Use per month	$0.04751	$0.04291
Seasonal Energy Charges		
First 180 Hours of Use per month	$0.08973	$0.03753
Next 180 Hours of Use per month	$0.06790	$0.03753
Over 360 Hours of Use per month	$0.04751	$0.03753
Customer Charge per Month	$74.84	
Facilities Charge ($/KW-Month)	$2.290	

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

A. The Company proposes a revenue increase of 13.03% for a systemwide increase of 13.99%. While my revenue allocation recommendation differs from the Company for the same systemwide increase, 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. Similar to the proposal for LPS, the Company proposes to align the customer charges and facility charges with its COSS results. With regards to changes in other charges, the remaining revenue requirement is collected via demand and energy charges with extra weighting given to demand charges as was done for the LPS rate. The higher cost recovery from fixed charges makes sense since over 95% of the revenue requirement increase is associated with increases in fixed costs.

Q. What concerns do you have regarding the Company's rate design proposal?

A. The Company proposes to increase the facility charges by 89% and 104% for the LGS secondary and primary classes respectively. I also do not feel comfortable in completely relying on the COSS results to increase the facility charges this significantly due to the issues regarding the classification and allocation of certain distribution plant related costs which may not be properly allocating costs to the LGS class and sub classes. Further, I am concerned that the LGS billing demand charges are very low and not consistent with cost of service guidance.[11]

Q. What do you recommend?

A. Assuming the same revenue requirement allocation as proposed by the Company to allow for an apples-to-apples comparison, my recommendation is as follows:

1. Increase facility charges no more than 1.75 times the existing rate for the two voltage service levels.
2. Retain the existing customer charge.
3. Retain the same percentage increase to energy charges as proposed by the Company.
4. Increase the billed demand charge to recover the remaining revenue requirement.

Q. Do you have any other comments regarding rate design?

A. Yes, I do. Company witness Mr. Brad Lutz has described the Company's proposed approach to phase out of the hours use rate design to a time variant rate design in a future rate case. He also identified that Evergy Missouri Metro's non-residential rates would transition towards a time variant rate sooner than EMW due to the presence of

[11] The Company's and MECG's COSS shows cost of service guidance for demand charges is above $15/KW-month.

the Annual Base Demand (or ABD) element in EMW's LGS and LPS rate design. He indicated that the ABD element would need to be addressed first before transitioning to a time variant rate due to bill impact considerations.[12]

Q. Do you support Mr. Lutz's view with regards to the transition to time variant rates?

A. Yes, I support Mr.Lutz's view that we need to consider rate impacts and transition towards time variant rates by addressing the ABD element as a first step as it relates to EMW LGS and LPS rates. In this regard, I recommend that the Company work collaboratively with MECG to develop and refine its proposed approaches before introducing these proposals in a future case.

Q. Does this conclude your direct testimony?

A Yes.

[12] See Mr. Brad Lutz's direct testimony on page 21.

Attachment 1

Evergy Missouri West
Case Name: 2024 Evergy MO West Rate Case
Case Number: ER-2024-0189

Requestor Opitz Timothy -
Response Provided July 09, 2024

Question:2.4

Please answer the following questions regarding Evergy Missouri West's three-phase and single-phase primary distribution circuits:

a. What portion of the cost of the Company's primary distribution system is associated with three-phase circuits? What portion is associated with single-phase circuits? Please provide the information in terms of both percentage of overall primary distribution system and, if available, as a percentage of net plant cost for the primary distribution system.

b. Are single-phase circuits used to provide service to primary voltage customers? If so, how many primary voltage customers does Evergy Missouri West serve and how many primary voltage customers receive their electric service via single-phase primary circuits?

c. What portion of the primary voltage customers' class load is served by single-phase circuits?

d. Are single-phase circuits primarily used to provide service to secondary voltage customers?

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: PUBLIC
Statement: This response is Public. No Confidential Statement is needed.

Response:

a. Company accounting systems do not differentiate system costs based on single phase or three phase configurations. Separately, the Company Mapping system does identify configuration. Based on that source, 61.4% of the Company total miles of circuits are single phase and 38.6% are three phase (including the two-phase configuration which is used to provide a form of three-phase service).

b. Company systems do not link the metering voltage to the circuit configuration, but anecdotally, it is rare that single-phase circuits are used to provide service to primary voltage customers. For the purpose of this data request, the Company would accept that there are no occurrences where single-phase circuits used to provide service to primary voltage customers.
c. Company systems do not differentiate load by single phase or three phase configurations. Please see the response to part "b" of this question.
d. Yes, where energy is distributed via single phase circuits, the customers on those circuits are primarily served via secondary voltages. It should be noted that the Company serves a considerable majority of customers via secondary voltages. As a result, customers on three phase circuits are also primarily served via secondary voltages.

Information provided by: Brad Lutz

Attachment(s):

Missouri Verification:

I have read the Information Request and answer thereto and find answer to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief; and I will disclose to the Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request(s).

Signature /s/ *Brad Lutz*
Director Regulatory Affairs