Exhibit No.:	
Issue:	Class Cost of Study, Revenue Allocation, Rate Design
Witness:	Kavita Maini
Type of Exhibit:	Direct Testimony
Sponsoring Parties:	Walmart Inc. and CCPS Transportation, LLC
Case No.:	25-EKCE-294-RTS
Date Testimony Prepared:	June 6, 2025

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. for Approval to Make Certain Changes in their Charges for Electric Service pursuant to K.S.A. 66-117	)))))	**File No. 25-EKCE-294-RTS**

Direct Testimony and Schedules of

Kavita Maini

On behalf of

Walmart Inc. and CCPS Transportation, LLC

June 6, 2025

Protecting Your Bottom Line

KM ENERGY CONSULTING, LLC

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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 33 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 Walmart Inc. ("Walmart") and CCPS Transportation, LLC ("CCPS"). Walmart takes service from Evergy Kansas Central ("EKC" or "Company") on its Medium General Service ("MGS") rate schedule at the secondary voltage service level while CCPS takes service from the Company on its Large General Service ("LGS") rate schedule at the transmission voltage service level.

Q. How are Walmart and CCPS impacted by this proceeding?

A. In this proceeding, EKC proposes an approximately $192 million increase in revenue requirement or 13.59% increase on a jurisdictional basis. For this increase, EKC proposes an 11.96% increase to the MGS class and 11.97% increase to the LGS class while the Company's own cost of service study supports a decrease of 18.1% to the MGS class and a decrease of 16.7% to the LGS class respectively. Further, within the LGS class, EKC's cost of service study supports a 43.8% decrease for customers served at transmission service level voltage.[1] Walmart and CCPS 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 MGS and LGS rate schedules. The rest of my testimony is organized as follows:

Section II: Class Cost of Service Study

Section III: Revenue Requirement Allocation

Section IV: MGS and LGS Transmission Rate Design

Q. Does the fact that you may not address an issue or position advocated by the Company indicate your support?

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[1] The specific percentages were obtained from the corrected class cost of study submitted in response to HF_Sinclair_10. The cost of service study results submitted in Company witness Ms. Marisol Miller's direct testimony related workpapers show that for a jurisdictional increase of 13.59%, MGS class should get a 18.4% decrease and LGS class should get a 16.4% decrease with LGS transmission at a 43.9% decrease.

A. No. The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of, agreement with, or consent to any filed position.

II. 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 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 manner 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 and proper allocation within the class that reflects costs to serve.

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 business customers, 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. 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 cost recovery is inconsistent with unit cost of service guidance, then the pricing signals are distorted and have the potential once again of sending inappropriate cost signals.

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

As noted by Company witness Ms. Marisol Miller, production plant is the single largest component cost to allocate to the classes within the study and as such, the production allocator has the most impact on the outcome of the CCOS study.[2]

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

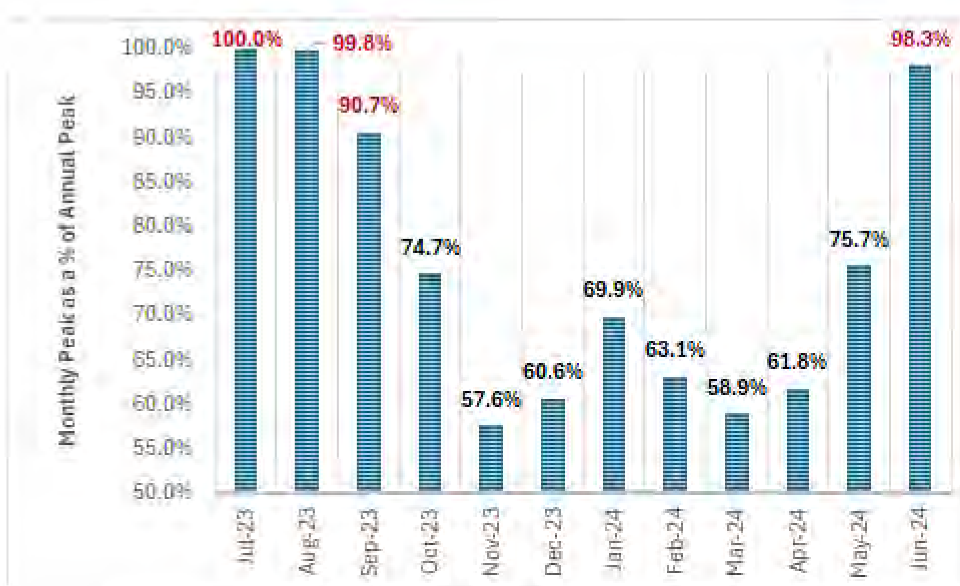
[2] See Ms. Miller's direct testimony on page 11.

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 EKC'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 EKC's system is summer peaking with the highest peak occurring in July, followed by August, June and September respectively. Since generation capacity is sized to reliably meet the highest peak demands, it would be appropriate and reflective of cost causation to consider class contributions to monthly demands for these fourth months.

Figure 1: Test Year EKC'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 Demand ("AED") 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 EKC's current case, class contributions coincident with the four highest demands for June through September would be appropriate to use in calculating the production cost allocator.

While the Peak Demand method relies solely on class contribution coincident with the relevant monthly peak demands, the AED methodology considers class contributions to maximum demands (for the summer peak months in EKC's case) and average demands. The AED approach considers the load profile of customer classes by incorporating the maximum demands, load factor and average demand.[3] While the average demand measures the duration and is weighted by the system load factor, the excess portion, calculated as the difference between average and maximum demand, measures the variability of the load profile of a class and is weighted by 1 minus the system load factor.

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

A. The Company uses the AED method for allocating fixed production costs. Ms. Marisol Miller testifies that after considerable efforts to determine the most appropriate

[3] The average demand is calculated by dividing the total kWh usage by the total hours in a year.

production allocation methodology in prior rate cases, the Company intends to continue to utilize the AED method. The Company used this method in the last rate case as well.

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

A The Company's AED approach relies on class contribution coincident with the four summer peak demands or 4CP to calculate the excess demand portion associated with each class.

Q. Is the Company's method for allocating fixed production plant related costs reasonable?

A. Yes. The Company uses the AED method and also recognizes that the cost causative importance of incorporating class contribution to maximum loads during the four summer months of June through September.

Q. Do you recommend any changes to the Company's COSS?

A. Not at this time. The Company's COSS is reasonable, and the related results can be relied on, to guide revenue allocation and rate design.

D. COSS: Company's COSS Results

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 2, EKC's earned rate of return ("ROR") under the class cost of service study is 5.43 % at present rates. As can be observed from Column 3, the Residential, Residential DG, Educational, and Restricted Time of Day Service class revenues are well below the EKC retail ROR level while the classes revenues are above for the Small General Service, Medium General Service, Large General Service, Large Power Service, Interruptible Service, Large Tire Manufacturer and Lighting classes respectively. The Company earned a negative return from the Special Contracts and EV classes. **Schedule KM-1** shows a summary of the COSS results.[4]

Figure 2: EKC COSS Rate of Return and Relative Rate of Return by Class at Present Rates

Column	1	2	3	4
Class	**Rate Base**	**Net Operating Income at Present Rates**	**Rate of Return (ROR) at Present Rates**	**Relative Rate of Return (ROR) at Present Rates**
Residential Total	$3,652,846,697	$78,118,769	2.14%	0.39
Residential DG	$27,705,410	$938,900	3.39%	0.62
Small General Service Total	$1,177,738,299	$110,289,217	9.36%	1.72
Medium General Service Total	$565,633,082	$65,541,445	11.59%	2.13
Large General Service Total	$677,285,213	$77,323,205	11.42%	2.10
Large Power Service Total	$101,124,590	$6,993,218	6.92%	1.27
Educational Services Total	$221,132,817	$5,536,219	2.50%	0.46
Restricted Time of Day Service	$8,198,683	$51,897	0.63%	0.12
Special Contracts	$184,153,215	($407,639)	-0.22%	-0.04
Interruptible Contract Service	$3,160,855	$589,121	18.64%	3.43
Large Tire Manufacturer	$16,935,605	$2,383,943	14.08%	2.59
EV Total	$3,091,803	($429,857)	-13.90%	-2.56
Lighting Total	$93,714,797	$18,772,625	20.03%	3.69
Total	**$6,732,721,065**	**$365,701,063**	**5.43%**	1.00

[4] The COSS Summary is from the corrected COSS model submitted by the Company in response to HF Sinclair_10. All the COSS related results presented in this testimony are from the corrected COSS model.

In Figure 2, the relative RORs[5] shown in Column 4 display wide deviations from 1 thereby reinforcing that at present rates, some classes are contributing significantly more than their costs to serve (with relative RORs more than 1 including but not limited to interruptible, MGS and LGS classes) while others are contributing significantly less than their costs (with relative RORs less than 1 including but not limited to the residential class). Classes with a negative relative ROR such as EV class imply that such classes are not fully covering their expenses. Therefore, there is a wide misalignment between the class cost and class revenue responsibility. This information provides important insights regarding cross subsidization and determining revenue allocation to move all rate classes closer to cost-based rates.

III. 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 establish fair and reasonable rates and should be used as the primary guiding principle in allocating revenue requirement to classes and informing rate design. Such an approach fulfills the important goals of promoting fairness among classes and encouraging economic efficiency.

Q. Can other factors also be 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

[5] Relative ROR is calculated as Class ROR divided by EKC retail system ROR at present rates.

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. 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 jurisdictional system average increase of 13.59%:

- Apply a 14.96% (approximately 110% of the jurisdictional rate increase) increase to the Residential, Churches, Schools, and EV/CCN, with the exception of BEV/ETS;
- Apply a 13.05% (approximately 96% of the jurisdictional rate increase) increase to the Large Power (ILP) and Special Contracts;
- Apply a 12.64% (approximately 93% of the jurisdictional rate increase) increase to SGS;
- Apply a 11.97% increase to the Large General Service class and 11.96% (approximately 88% of the jurisdictional rate increase) increase to the Medium General Service, Large Tire Manufacturer, Interruptible Contract, and Lighting Classes.

Q. How does the Company's revenue allocation proposal compare with the Company's COSS results?

A. Figure 3 shows a comparison between the Company's COSS based multiplier and related increases with the Company's proposed revenue allocation multiplier and related increases. Generally speaking, the Company's revenue allocation is directionally consistent with the COSS results where classes with relative RORs below 1 are proposed to get an above jurisdictional system average increase and classes with relative RORs above 1 are proposed to get a below jurisdictional system average increase. Given an approximately 14% average jurisdictional increase, it appears that EKC has made considerable efforts to moderate the rate impacts to certain classes such as the residential class compared to the COSS results. I am concerned, however, at the trade-off with fairness to certain other classes. For instance, the Company's COSS results show double digit decreases for certain classes are warranted, including but not limited to the medium general service class and the large general service class, even after applying the Company's proposed increase.[6] Such classes will end up substantially subsidizing other classes under the Company's proposal.

Figure 3: Comparison of a Cost Based Multiplier from EKC's COSS and Percent Increase with EKC's proposed Revenue Allocation Multiplier and Percent Increase

Column	1	2	3	4
Class	EKC COSS Multiplier	COSS Percent Increase	EKC Revenue Allocation Multiplier	EKC Proposed Increase
Residential Total	295%	40.1%	110%	14.96%
Residential DG	205%	27.9%	110%	14.96%
Small General Service Total	-63%	-8.6%	93%	12.64%
Medium General Service Total	-134%	-18.1%	88%	11.96%
Large General Service Total	-123%	-16.7%	88%	11.97%
Large Power Service Total	30%	4.0%	96%	13.05%
Educational Services Total	280%	38.1%	110%	14.96%
Restricted Time of Day Service	445%	60.5%	110%	14.96%
Special Contracts	411%	55.9%	96%	13.05%
Interruptible Contract Service	-302%	-41.0%	88%	11.96%
Large Tire Manufacturer	-211%	-28.7%	88%	11.96%
EV Total	54882%	7456.2%	90%	12.18%
Lighting Total	-393%	-53.4%	88%	11.96%
Total		13.59%		13.59%

[6] Within the LGS class, the COSS results for the LGS transmission sub class show that this sub class should receive approximately 44% rate decrease for the system wide increase of 13.59%. While I discuss the allocation to the LGS class in this section, I have recommendations for revenue allocation within the LGS class in the rate design section in order to make corrections to the massive gap between LGS Transmission's revenue and cost responsibility.

Q. Do you have an alternative recommendation for the Commission to consider?

A. Yes, I do. While I appreciate that EKC's recommended revenue allocation is generally consistent with the cost of service study results from a directional perspective, in my view, bigger steps should be taken compared to the Company's proposal, to move classes towards the COSS results to achieve a better balance between fairness and moderation.

Walmart and CCPS' recommended multipliers by class are shown in comparison to EKC's multipliers in Figure 4 below.

Figure 4: Walmart and CCPS Recommended Revenue Allocation Multiplier

Column	1	2	3
Class	EKC Revenue Allocation Multiplier	Walmart and CCPS Revenue Allocation Multiplier	Walmart and CCPS
Residential Total	110%	125%	17.00%
Residential DG	110%	125%	17.00%
Small General Service Total	93%	82%	11.15%
Medium General Service Total	88%	70%	9.51%
Large General Service Total	88%	70%	9.51%
Large Power Service Total	96%	91%	12.37%
Educational Services Total	110%	125%	17.00%
Restricted Time of Day Service	110%	125%	17.00%
Special Contracts	96%	91%	12.37%
Interruptible Contract Service	88%	70%	9.51%
Large Tire Manufacturer	88%	70%	9.51%
EV Total	110%	125%	17.00%
Lighting Total	88%	70%	9.51%

It is worth noting the following:

- While my multipliers are aimed at getting classes closer to COSS results compared to the Company's proposal, I followed the same groupings as the Company with regards to the same multiplier being applied to certain classes except for the EV class.[7] The groupings, aimed at identifying above and below system average increases, are directionally consistent with the ROR and relative ROR results discussed earlier.

- I deviated from the Company's policy in that I applied 125% multiplier to the total EV class with no exceptions since this class has a negative return. The only other class with negative return is Special Contracts. EKC recommends the same increase to this class as the LPS class. Since this recommendation may be tied to a contractual provision, I followed the Company's policy of the same multiplier as the LPS class and related increase to the Special Contracts class as recommended by the Company.
- While my recommended multipliers are aimed at getting closer to the Company's COSS results compared to the Company's proposal, I have also employed substantive moderation to temper the rate impacts to certain classes as can be observed by comparing my recommended revenue allocation with the Company's COSS results shown in Figure 3 (Column 2). I have allocated significantly more of the revenue requirement than is supported by the COSS results which actually show a double digit decrease to certain classes such as the MGS class. In developing my recommendation, however, it was necessary to temper rate impacts associated with the Company's proposed 13.59% system average increase. In this regard, therefore, I made considerable efforts to balance getting classes closer to cost while at the same time moderating the rate impacts for certain classes.

Q. What do you recommend to the Commission?

[7] For instance, similar to the Company, the residential and educational classes received the same multiplier and increase. Similarly, the MGS, LGS, ICS and LTM classes received the same multiplier and related increase.

A. At a minimum, I recommend Walmart and CCPS' recommended multipliers shown in Figure 4, Column 2 be applied to allocate the increase in the revenue requirement. However, it would be reasonable for the Commission to make larger adjustments than what I have recommended to move rates closer to costs to serve if the ultimate increase in revenue requirement awarded is lower than the Company's initial request.

IV. RATE DESIGN

A. MGS Default Rate

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

A The main unit charges consist of a flat customer charge, demand and energy charges. The energy charges are seasonally differentiated. There is no voltage level differential in the MGS class.

Figure 5 shows the existing rate applicable to the MGS class.

Figure 5: Existing MGS Rate

Customer Charge	$131.77
Energy Charge (per kWh)	
Summer	$0.01610
Winter	$0.01223
Demand Charge (per KW)	$17.970

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

A. The Company proposes a revenue increase of 11.97% for a systemwide increase of 13.59%. As discussed earlier, I do not support this increase for the MGS class and provided an alternative recommendation for the same systemwide increase.

Q. What are the Company's proposed increases to the various components of the MGS rate?

A. The Company proposes increasing all components using the same increase at the revenue allocation increase to the class.

Q. Do you support the Company's approach of applying the same percentage increase to all the charges as the revenue allocation increase?

A. Yes, I do. While I do not support the revenue allocation increase to the class, I support the same percent increase to all the charges as the revenue allocation increase to the class. This is because the proportional shares of the customer, demand and energy charges being recovered from present rates are a reasonable reflection of COSS guidance regarding costs to be recovered from the various charge components. Figure 6 shows this comparison.

Figure 6: Share by Charge Component for MGS Class : Present Rates v. COSS[8]

	Present Rates	COSS
Customer	1.4%	0.4%
Energy	20.9%	17.2%
Demand	77.7%	82.4%
	100.0%	100.0%

B. LGS Default Rate

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

A. The main unit charges consist of a flat customer charge, demand, and energy charges. The charges vary by secondary, primary and transmission voltage service levels. Figure 7 shows the existing rate applicable to the LGS class by voltage service level.

[8] Present Rate Percent Share from Blue Sheets and COSS percent share from corrected COSS Model (Unit COS tab) in response to HF Sinclair_10.

Figure 7: LGS Charge Components at Present Rates

Voltage Level	Secondary	Primary	Transmissior
Customer Charge	$356.66	$356.66	$356.66
Energy Charge (per kWh)	$0.01433	$0.01433	$0.01361
Demand Charge (per KW)	$17.188	$16.050	$13.042

Q. What are the Company's proposed increases to the various components of the LGS rate?

A. The Company proposes increasing all components using the same increase at the revenue allocation increase to the class.

Q. Do you support the Company's proposal for the LGS Transmission Service class?

A. No. Specifically, I do not support any increase to the LGS Transmission sub class because the COSS results show a decrease of approximately 44% for a system wide increase of 13.6%. The revenue allocation increase to the LGS class needs to be allocated between the secondary and primary sub classes.

At present rates, the LGS Transmission class has an ROR of 21.23% and a relative ROR of 3.91 which is twice that of the secondary and primary sub classes. Given the substantial misalignment of cost and revenue responsibility, it does not seem fair or reasonable to assign an increase to the LGS Transmission sub class. Any increase would further exacerbate the massive deviation from the COSS results. Figure 8 shows the COSS result summary for the LGS Transmission sub class.

Figure 8: LGS and LGS Transmission Company COSS Result Summary

	KS Central Retail	Large General Service Total	LGS Transmission
Rate Base	$6,732,721,065	$677,285,213	$71,411,760
Net Operating Income at Present Rates	$365,701,063	$77,323,205	$15,159,784
Rate of Return at Present Rates	5.43%	11.42%	21.23%
Relative Rate of Return	1.00	2.10	3.91
EQUALIZED RATE OF RETURN			
Rate Base	$6,732,721,065	$677,285,213	$71,411,760
Equalized Rate of Return	7.6856%	7.6856%	7.6856%
Relative Rate of Return	1.00	1.00	1.00
Return Required @ Equalized Rate of Return	$517,450,010	$52,053,432	$5,488,422
Gross Revenue Deficiency	$192,086,852	($31,986,984)	($12,242,203)
Revenue Under Present Rates	1,413,874,780	$191,532,412	$27,963,297
% Adjustment	13.6%	-16.7%	-43.8%

Q. What do you believe is the major driver contributing to this misalignment?

A. Based on the COSS results as well as the unbundled cost components in the Optional Time of Use rate, I believe that the biggest driver is that the LGS Transmission sub class has been paying and is being asked to continue to pay for distribution related assets and costs, which this sub class has neither utilized nor has caused because the customers in this class take service at the transmission level. Figure 9 shows the distribution plant related costs assigned to the secondary, primary and transmission voltage service levels in the COSS. As can be observed, there should be no distribution related costs included for recovery in the LGS transmission rate.

Figure 9: LGS and LGS Transmission Company COSS Result Summary

	Large General Service Total	LGS Secondary	LGS Primary	LGS Transmission
Distribution Demand Substations	$10,492,454	$5,177,300	$5,315,154	$0
Distribution Demand Primary Lines and Poles	$13,703,640	$6,761,797	$6,941,843	$0
Distribution Demand Secondary Lines and Poles	$1,987,303	$1,987,303	$0	$0

Q. What does the proposed Optional Time of Use rate applicable to LGS Transmission show as facility charges in existing rates?

A. The Optional Time of Use rate applicable to LGS Transmission shows that $5.65 million in facilities charges are included in the existing LGS Transmission rate. Figure 10 shows the breakdown by the various components provided as workpapers in support of the Optional Time of Use rate.

Figure 10: Company Provided Breakdown of Cost Components for LGS Transmission[9]

Item	Unit	LGS Transmission
Customer Count	#	21
Billed Energy	kWh	504,875,387
Billed Revenue	$	$27,779,459
Production Demand	$	$16,991,751
Production Energy	$	$5,126,275
Distribution Demand	$	$5,650,965
Distribution Customer	$	$6,012
Customer	$	$4,456
Total Customer Costs	$	$10,468
Total Revenue	$	$27,779,459
Revenue Neutrality	$	TRUE

[9] See 2025.01.28_Cost Summary Workpapers included in Workpapers for Mr. Bradley Lutz.

Q. What does the COSS show as the differential between LGS secondary, primary and transmission demand charges?

A. As can be observed in Figure 11, the COSS shows that the LGS transmission demand charges should be around half of the charges at the primary voltage service level ($8.91/16.83=53%) or $8/KW lower than the LGS primary voltage service level. At present rates, they are 81% of the LGS primary rate ($13.042/$16.050=81%) or $3/KW lower. While this differential may not be entirely attributable to distribution infrastructure related increases through facility charges, it reinforces that the LGS transmission rates need to be corrected to properly reflect the cost of service at the transmission service level relative to lower voltage service levels.

Figure 11: LGS Demand Charges: Existing vs. COSS Results[10]

	Existing Demand Charge	Differentials	COSS Results	Differentials
LGS Secondary	$17.188		$16.92	
LGS Primary	$16.050	-$1.138	$16.83	-$0.092
LGS Transmission	$13.042	-$3.008	$8.91	-$7.922

C. Optional Time of Use ("TOU") Rate

Q. What is the Company's proposed optional TOU rate for C&I customers?

A. The Company proposes a four part rate that consists of a customer charge, demand charge, energy charge and facilities charge. The demand charge only applies in the summer with billing demand being set within a four hour window. The energy charge is time-differentiated in three-parts in the summer and two-parts in the winter with the

[10] Unit COS tab in COSS model.

on-peak charge applying only in the summer. The facilities charge is aimed at recovering distribution related costs.

Q. What is your overarching perspective about this rate?

A. From a conceptual standpoint, I am supportive of a four part rate design that attempts to unbundle the cost categories into customer, facilities demand charge, generation demand charge and energy charges respectively. I am also supportive of time differentiating the energy charges as proposed by the Company.

However, there are some aspects of the rate that need modification. In my view, the rate should be designed to be more reflective of embedded costs with regards to the energy and demand charges. The Company's rate design is focused entirely on targeting customers that can respond to pricing signals. However, in the process, the vast majority of fixed generation costs are recovered through volumetric components. Fixed cost recovery through volumetric rates provides an erroneous pricing signal that capacity is cheaper than is actually the case. Instead, I believe that it would be more effective to design the energy and demand charges such that they more closely reflect embedded costs to serve, have elements of higher prices in the summer, and encourage customers to adopt time variant rates. We must be mindful of the fact that the current MGS rate has no time differentiated element. Instead of providing a rate option that is very advanced and aimed predominantly at eliciting response by artificially increasing certain prices at certain times of the year, a more gradual approach of introducing customers to time variant rate options may be appropriate for greater acceptability. I recognize that the Company's proposal is aimed at being an option. However, it would make sense to introduce a rate that garners more acceptability and adoption while at the same time being more reflective of embedded costs to serve.

Q. What are your recommendations for the MGS Optional TOU Rate?

A. My recommendations are as follows:

1. I support a facility charge to recover all COSS related distribution costs;
2. Instead of recovering only 27% of the costs through demand charges, I recommend that 95% of the fixed generation costs be recovered through demand charges and 5% from the on-peak summer energy charge.
3. Further, instead of a summer only demand charge, I recommend a year around demand charge that recovers 85% of the fixed generation costs that are to be recovered through an average annual demand charge with the remaining 15% to be added for the summer. This will result in the summer charge being approximately $6/KW-month higher than the demand charge in the non-summer months.
4. I reviewed the LGS time variant rate from the Evergy Kansas Metro jurisdiction. The concept I recommend here, of recovering demand charges throughout the year with a higher charge in the summer, is similar to the Company's approach to the LGS rate in the Kansas Metro jurisdiction, which includes a higher demand charge in the summer compared to the non-summer months. (See **Attached Schedule KM-2**: LGS Rate Every Kansas Metro)
5. As it relates to the billing determinants to use for demand charges, it would be preferable to use a larger window for setting the billing demand in order to have a more balanced trade-off between the amount of billing determinants and providing a price signal. For instance, in Wisconsin, utilities generally have 12-hour window for setting demand.

Since this aspect will require more vetting, it would be reasonable to use the maximum demand for the month (without ratchets) for setting the billing demand with the goal of working on a time differentiated window for demand in advance of the next rate case.

6. I do not oppose the proposed time differentiated energy relationships. It is important to note that a separate rider called Retail Energy Cost Adjustment or RECA is used to recover the majority of the fuel costs. In developing my recommendation, I was mindful of the fact that separate energy charges would be added to recover the fuel costs which are not time differentiated. The RECA charges are flat energy charges, with the same charge applicable to call classes. For the test year time period, the charges ranged from a low of \$0.02/kWh to a high of \$0.025/kWh. In my recommended rate design shown in Figure 12, the on peak energy charge would be over \$0.08/kWh after including the RECA charges as an appropriate pricing signal for customers to respond to, in the summer on peak hours.

Q. What is your recommended rate at present rate revenues for the MGS class?

A. Figure 11 shows my recommended rate for recovering the same revenue for the MGS class as proposed by the Company, which is at existing rates. This figure is illustrative of the impact of my adjustments to the Company's proposal to remove almost all of the fixed generation charges from the energy charges.

Figure 11: Suggested Optional TOU Rate for MGS Class at Present Rates

Rate Component		Units	MGS
Fixed Charge			
Customer Charge		$/month	$131.77
Seasonal Energy-Based			
Summer	Peak	$/kWh	$0.06073
Summer	Off	$/kWh	$0.01207
Summer	Super Off	$/kWh	$0.00412
Winter	Off	$/kWh	$0.00902
Winter	Super Off	$/kWh	$0.00319
Demand-Based			
Summer Demand Charge		$/kW-Month	$17.528
Winter Demand Charge		$/kW-Month	$11.819
Facilities Charge		$/kW-Month	$3.404

Q. What are your recommendations for modifying the LGS Transmission Optional TOU rate?

A. My recommendations are as follows:

1. First, for reasons identified earlier including the COSS results, there should be no facilities charge cost recovery associated with the LGS Transmission rate.
2. Second, in Table 1 of page 7 in Mr. Brad Lutz' direct testimony, the proposed energy charges at LGS Transmission are higher than the energy charges proposed for LGS secondary and primary rates which fails to recognize the loss differentials. The energy rates at the transmission level should be the lowest compared to the lower voltages due to the difference in losses as can be observed in the default LGS rates (see Figure 7). Since the Optional TOU rate is revenue neutral at the LGS transmission level, it would suggest that some additional costs were included in the energy charges which changed the foundational relationship between the transmission service voltage and other voltage service levels. I make this assertion because in the default rate, the energy charge differentials are directionally consistent. I recommend that the Company rectify the flaw with regards to the energy charges applicable to LGS Transmission.

3. I recommend the same approach for the LGS rate as described for the MGS rate with regards to setting generation demand charges.[11]
4. Figure 12 is illustrative of the summer and winter demand charges for LGS secondary, primary and transmission voltage service levels resulting from my adjustments.

Figure 12: Demand Charges for LGS Optional TOU

	Summer	Non-Summer
LGS Secondary	$17.87	$11.73
LGS Primary	$16.77	$11.10
LGS Transmission	$13.06	$8.60

Q. The Company convened meetings with certain stakeholders about developing the optional TOU rate in 2024, why did you not provide this feedback to the Company during discussions prior to the rate case?

A. I have been supportive of the concept of the four-part rate design. However, I was not able to review all the specifics of the charges until I received access to the COSS and other rate information which only became available after the rate case was filed. Submitting direct testimony is the first opportunity for providing feedback to the Company. Both Walmart and CCPS are very appreciate of the Company's willingness to offer an optional TOU rate. I would very much appreciate working collaboratively with the Company to refine the rate design so that it is reflective of cost based rates while at the same time includes provisions for price differentials between summer and winter months.

Q. Does this conclude your direct testimony?

A. Yes.

[11] That is, the same steps as I described under #2 and #3 in the MGS Optional TOU recommendations earlier.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. for Approval to Make Certain Changes in their Charges for Electric Service.	))))	Docket No. 25-EKCE-294-RTS

AFFIDAVIT OF KAVITA MAINI

STATE OF WISCONSIN)
)
COUNTY OF WAUKESHA)

COMES NOW Kavita Maini and on her oath declares that she is of sound mind and lawful age; that she prepared the attached testimony; and that the same is true and correct according to her best knowledge and belief, under penalty of perjury.

Further the Affiant sayeth not.

Kavita Maini
Kavita Maini

Subscribed and sworn to be this 5 day of June 2025.

ANNIE CODERRE JONES
NOTARY PUBLIC
STATE OF WISCONSIN

Annie Coderre Jones
Notary Public
exp.: 06/13/2028

Schedule KM-1: COSS Results Summary

Test Year 2024 Cost of Service Summary

		KS Central Retail	Residential Total	Residential DG	Small General Service Total	Medium General Service Total	Large General Service Total	Large Power Service Total	Educational Services Total	Restricted Time of Day Service	Special Contracts	Interruptible Contract Service	Large Tire Manufacturer	EV Total	Lighting Total
REVENUE REQUIREMENT SUMMARY															
RETURN AT PRESENT RATES															
Rate Base	0	$ 6,732,721,065	$ 3,652,846,697	$ 27,705,410	$1,177,738,299	$ 565,633,082	$ 677,285,213	$ 101,124,590	$ 221,132,817	$ 8,198,683	$ 184,153,215	$ 3,160,855	$ 16,935,605	$ 3,091,803	$ 93,714,797
Net Operating Income at Present Rates	0	$ 365,701,063	$ 78,118,769	$ 938,900	$ 110,289,217	$ 65,541,445	$ 77,323,205	$ 6,993,218	$ 5,536,219	$ 51,897	$ (407,639)	$ 589,121	$ 2,383,943	$ (429,857)	$ 18,772,625
Rate of Return at Present Rates		**5.43%**	**2.14%**	**3.39%**	**9.36%**	**11.59%**	**11.42%**	**6.92%**	**2.50%**	**0.63%**	**-0.22%**	**18.64%**	**14.08%**	**-13.90%**	**20.03%**
Relative Rate of Return		1.00	0.39	0.62	1.72	2.13	2.10	1.27	0.46	0.12	(0.04)	3.43	2.59	(2.56)	3.69
EQUALIZED RATE OF RETURN															
Rate Base		$ 6,732,721,065	$ 3,652,846,697	$ 27,705,410	$1,177,738,299	$ 565,633,082	$ 677,285,213	$ 101,124,590	$ 221,132,817	$ 8,198,683	$ 184,153,215	$ 3,160,855	$ 16,935,605	$ 3,091,803	$ 93,714,797
Equalized Rate of Return		7.6856%	7.6856%	7.6856%	7.6856%	7.6856%	7.6856%	7.6856%	7.6856%	7.6856%	7.6856%	7.6856%	7.6856%	7.6856%	7.6856%
Relative Rate of Return		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Return Required @ Equalized Rate of Return		$517,450,010	$280,743,186	$2,129,327	$90,516,255	$43,472,296	$52,053,432	$7,772,031	$16,995,384	$630,118	$14,153,279	$242,931	$1,301,603	$237,624	$7,202,544
Revenue Deficiency from Present Rates		$151,748,947	$202,624,417	$1,190,427	($19,772,963)	($22,069,149)	($25,269,773)	$778,814	$11,459,165	$578,221	$14,560,918	($346,191)	($1,082,340)	$667,481	($11,570,080)
Effective Tax Rate	21.0000%														
Additional Current Tax Required		$40,337,905	$53,861,623	$316,439	($5,256,049)	($5,866,421)	($6,717,211)	$207,024	$3,046,075	$153,703	$3,870,583	($92,024)	($287,708)	$177,430	($3,075,559)
Gross Revenue Deficiency		$192,086,852	$256,486,040	$1,506,866	($25,029,012)	($27,935,570)	($31,986,984)	$985,838	$14,505,240	$731,924	$18,431,502	($438,215)	($1,370,048)	$844,911	($14,645,639)
Revenue Under Present Rates		1,413,874,780	640,306,516	$5,403,843	$292,682,279	$153,953,501	$191,532,412	24,475,789	38,067,845	1,209,672	32,986,239	1,069,498	4,770,313	11,332	27,405,542
Indicated % Adjustment		13.6%	40.1%	27.9%	-8.6%	-18.1%	-16.7%	4.0%	38.1%	60.5%	55.9%	-41.0%	-28.7%	7456.2%	-53.4%
COSS Multiplier		100%	295%	205%	-63%	-134%	-123%	30%	280%	445%	411%	-302%	-211%	54882%	-393%

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THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO

(Name of Issuing Utility)

EVERGY KANSAS METRO RATE AREA

(Territory to which schedule is applicable)

SCHEDULE LGS

Replacing Schedule LGS Sheet 1

which was filed November 24, 2020

No supplement or separate understanding shall modify the tariff as shown hereon.

LARGE GENERAL SERVICE
Schedule LGS

AVAILABILITY

For electric service through one meter to a customer using electric service for purposes other than those included in the availability provisions of the Residential Service Rate Schedule. At the Company's discretion, service may be provided through more than one meter where it is economical for the Company to do so.

For electric service through a separately metered circuit for water heating connected prior to March 1, 1999.

For secondary electric service through a separately metered circuit for electric space heating purposes. Electric space heating equipment may be supplemented by or used as a supplement to wood burning fireplaces, wood burning stoves, active or passive solar heating, and in conjunction with fossil fuels where the combination of energy sources results in a net economic benefit to the customer. Electric space heating equipment shall be permanently installed, thermostatically controlled, and of a size and design approved by the Company. In addition to the electric space heating equipment, only permanently installed all electric equipment, used to cool or air condition the same space which is electrically heated, may be connected to the separately metered circuit.

Standby, breakdown, or supplementary service will not be supplied under this schedule unless the customer first enters into a special contract which includes technical and safety requirements. These requirements, and the associated interconnection costs, shall be reasonable and assessed on a nondiscriminatory basis with respect to other customers with similar load characteristics. Temporary service supplied under this schedule will be connected and disconnected in accordance with the General Rules and Regulations.

APPLICABILITY

Applicable to multiple-occupancy buildings when the tenants or occupants of the building are furnished with electric service on a rent inclusion basis and the customer qualifies under Sections 9.03 – 9.08 of Company's General Rules and Regulations pertaining to Metering.

This rate also will be applied to the combined use of a customer at the premises where two or more classes of service (such as one-phase and three-phase services) to the customer at such premises are measured by separate meters, but only in the case of customers connected prior to August 25, 1976. Monthly Maximum Demand will be computed as the sum of the individual meters' monthly maximum 30-minute interval demand. Customers with more than one class of service connected on or after August 25, 1976, will be billed separately for each class of service.

Issued	April	25	2023
	Month	Day	Year
Effective	December	21	2023
	Month	Day	Year

By

Darrin Ives, Vice President

23-EKCE-775-RTS
Approved JG
Kansas Corporation Commission
November 21, 2023
/s/ Lynn Retz

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THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

SCHEDULE LGS

Replacing Schedule LGS Sheet 2

which was filed November 24, 2020

No supplement or separate understanding shall modify the tariff as shown hereon.

LARGE GENERAL SERVICE
Schedule LGS

If the customer billing demand reaches or exceeds 1,500 kW in any one billing month during a twelve-month period, the customer will be reclassified and will prospectively take service pursuant to the rates, terms, and conditions of the Large Power Service rate schedule or other applicable tariff.

TERM OF CONTRACT

Contracts under this schedule shall be in accordance with the General Rules and Regulations, generally for a period of not less than one year from the effective date thereof, except in the case of temporary service.

RATE FOR SERVICE AT SECONDARY VOLTAGE: 2LGSE, 2LGSEW, 2LGSEWP,

1. CUSTOMER CHARGE:

   A. Customer pays one of the following charges per month based upon the Facilities Demand:

0 - 999 kW	$102.86
1000 kW or above	$703.51

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month $2.979

3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$11.683	$5.598

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
On-Peak	$0.07852 per kWh	$0.04146 per kWh
Off-Peak	$0.04182 per kWh	$0.03538 per kWh

5. DEMAND CHARGE: (FOR NET METERING AND PARALLEL GENERATION)

	Summer Season	Winter Season
Per kW of Billing Demand per month	$6.433	$3.266

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By Darrin Ives, Vice President

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/s/ Lynn Retz

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THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

SCHEDULE LGS

Replacing Schedule LGS Sheet 3

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

which was filed November 24, 2020

No supplement or separate understanding shall modify the tariff as shown hereon.

LARGE GENERAL SERVICE
Schedule LGS

6. ENERGY CHARGE: (FOR NET METERING AND PARALLELL GENERATION)
Per kWh associated with:

	Summer Season	Winter Season
First 180 Hours Use per month	$0.06409 per kWh	$0.06425 per kWh
Next 180 Hours Use per month	$0.04581 per kWh	$0.03903 per kWh
Over 360 Hours Use per month	$0.02620 per kWh	$0.02916 per kWh

RATE FOR SERVICE AT PRIMARY VOLTAGE: 2LGSF, 2LGSFP, 2LGSFW

1. CUSTOMER CHARGE:
Customer pays one of the following charges per month based upon the Facilities Demand:

0 - 999 kW	$102.86
1000 kW or above	$703.51

2. FACILITIES CHARGE:
Per kW of Facilities Demand per month $2.501

3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$11.744	$5.698

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
On-Peak	$0.07299 per kWh	$0.03854 per kWh
Off-Peak	$0.03888 per kWh	$0.03288 per kWh

5. DEMAND CHARGE: (FOR NET METERING AND PARALLEL GENERATION)

	Summer Season	Winter Season
Per kW of Billing Demand per month:	$6.313	$3.194

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By [signature]
Darrin Ives, Vice President

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November 21, 2023
/s/ Lynn Retz

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THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

SCHEDULE LGS

Replacing Schedule LGS Sheet 4

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

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LARGE GENERAL SERVICE
Schedule LGS

6. ENERGY CHARGE: (FOR NET METERING AND PARALLEL GENERATION)
   Per kWh associated with:

	Summer Season	Winter Season
First 180 Hours Use per month	$0.06226 per kWh	$0.06225 per kWh
Next 180 Hours Use per month	$0.04444 per kWh	$0.03813 per kWh
Over 360 Hours Use per month	$0.02521 per kWh	$0.02844 per kWh

RATE FOR SERVICE AT SUBSTATION VOLTAGE: 2LGSU

1. CUSTOMER CHARGE:
   Customer pays the following charge per month $751.02

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month $0.793

3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month:	$12.562	$5.796

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
On-Peak	$0.06863 per kWh	$0.03624 per kWh
Off-Peak	$0.03656 per kWh	$0.03092 per kWh

5. DEMAND CHARGE: (FOR NET METERING AND PARALLEL GENERATION)

Per kW of Billing Demand per month:	Summer Season	Winter Season
First 2520 kW	$10.938	$7.434
Next 2520 kW	$10.216	$6.778
Next 2520 kW	$7.523	$5.253
All kW over 7560 Kw	$5.491	$4.042

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/s/ Lynn Retz

Schedule KM-2

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THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

SCHEDULE LGS

Replacing Schedule LGS Sheet 5

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

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No supplement or separate understanding shall modify the tariff as shown hereon.

LARGE GENERAL SERVICE
Schedule LGS

6. ENERGY CHARGE: (FOR NET METERING AND PARALLEL GENERATION)

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.05327 per kWh	$0.04982 per kWh
Next 180 Hours Use per month	$0.03229 per kWh	$0.03518 per kWh
Over 360 Hours Use per month	$0.01869 per kWh	$0.02541 per kWh

RATE FOR SERVICE AT TRANSMISSION VOLTAGE: 2LGSW

1. CUSTOMER CHARGE:
   Customer pays the following charge per month: $751.02

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month $0.000

3. DEMAND CHARGE:

Per kW of Billing Demand per month:	Summer Season	Winter Season
	$12.562	$5.796

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
On-Peak	$0.06811 per kWh	$0.03597 per kWh
Off-Peak	$0.03628 per kWh	$0.03069 per kWh

5. DEMAND CHARGE: (FOR NET METERING AND PARALLEL GENERATION)

Per kW of Billing Demand per month:	Summer Season	Winter Season
First 2541 kW	$10.840	$7.368
Next 2541 kW	$10.124	$6.718
Next 2541 kW	$7.480	$5.223
All kW over 7623 kW	$5.460	$4.020

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By Darrin Ives
Darrin Ives, Vice President

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November 21, 2023
/s/ Lynn Retz

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THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

SCHEDULE LGS

Replacing Schedule LGS Sheet 6

which was filed November 24, 2020

No supplement or separate understanding shall modify the tariff as shown hereon.

LARGE GENERAL SERVICE
Schedule LGS

6. ENERGY CHARGE: (FOR NET METERING AND PARALLEL GENERATION)

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.05260 per kWh	$0.04930 per kWh
Next 180 Hours Use per month	$0.03189 per kWh	$0.03478 per kWh
Over 360 Hours Use per month	$0.01828 per kWh	$0.02499 per kWh

REACTIVE DEMAND ADJUSTMENT (Secondary, Primary, Substation, and Transmission Service)

Company may determine the customer's monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.663 per month shall be made for each kilovar by which such maximum reactive demand is

greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

MINIMUM MONTHLY BILL

The Minimum Monthly Bill shall be equal to the sum of the Customer Charge, Facilities Charge, Demand Charge, and Reactive Demand Adjustment.

SUMMER AND WINTER SEASONS

For determination of Seasonal periods, the four (4) summer months shall be defined as the four (4) monthly billing periods of June through September. The eight (8) winter months shall be defined as the eight (8) monthly bill periods of October through May. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

CUSTOMER DEFINITIONS

Secondary Voltage Customer - Receives service on the low side of the line transformer.

Primary Voltage Customer - Receives service at Primary voltage of 12,000 volts or over but not exceeding 69,000 volts. Customer will own all equipment necessary for transformation including the line transformer.

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By [signature]
Darrin Ives, Vice President

23-EKCE-775-RTS
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November 21, 2023
/s/ Lynn Retz

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THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

SCHEDULE LGS

Replacing Schedule LGS Sheet 7

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No supplement or separate understanding shall modify the tariff as shown hereon.

LARGE GENERAL SERVICE
Schedule LGS

Water Heating Customer - Customer connected prior to March 1, 1999, that receives service through a separately metered circuit as the sole means of water heating with an electric water heater of a size and design approved by the Company.

Substation Voltage Customer - Service is taken directly out of a distribution substation at primary voltage. The customer will own the feeder circuits out of this substation.

Transmission Voltage Customer - The customer owns, leases, or otherwise bears financial responsibility for the distribution substation. Service is taken off of the Company's transmission system.

DETERMINATION OF DEMANDS

Demand will be determined by demand instruments or, at the Company's option, by demand tests.

MINIMUM DEMAND

200 kW for service at Secondary Voltage.
204 kW for service at Primary Voltage.
1008 kW for service at Substation Voltage.
1016 kW for service at Transmission Voltage.

MONTHLY MAXIMUM DEMAND

The Monthly Maximum Demand is defined as the sum of:

a. The highest demand indicated in any 30-minute interval during the month on all non-space heat and non-water heat meters.

b. Plus, the highest demand indicated in any 30-minute interval during the month on the space heat meter, if applicable.

c. Plus, the highest demand indicated in any 30-minute interval during the month on the water heat meter, if applicable.

Issued April 25 2023
Month Day Year

Effective December 21 2023
Month Day Year

By [signature]
Darrin Ives, Vice President

23-EKCE-775-RTS
Approved JG
Kansas Corporation Commission
November 21, 2023
/s/ Lynn Retz

LARGE GENERAL SERVICE
Schedule LGS

FACILITIES DEMAND

Facilities Demand shall be equal to the higher of: (a) the highest Monthly Maximum Demand occurring in the last twelve (12) months including the current month or (b) the Minimum Demand.

DETERMINATION OF HOURS USE

For Net Metering and Parallel Generation, Total Hours Use in the Summer Season shall be determined by dividing the total monthly kWh on all meters by the Monthly Maximum Demand in the current month. Total Hours Use in the Winter Season shall be determined by dividing the total monthly kWh on all meters (excluding separately metered space heat kWh) by the Monthly Maximum Demand (excluding separately metered space heat kW) in the current month. The kWh associated with a given number of Hours Use is computed by multiplying the Monthly Maximum Demand (excluding separately metered space heat kW in the Winter Season) by that number of Hours Use.

PRICING PERIODS

Pricing periods are established in Central Standard Time year-round. The hours for each pricing period are as follows:

On-Peak	3pm-7pm, Monday through Friday, except holidays.
Off-Peak	All other hours

Holidays are New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

METERING AT DIFFERENT VOLTAGES

The Company may, at its option, install metering equipment on the secondary side of a Primary Voltage Customer's transformer. In that event, the customer's metered demand and energy shall be increased either by the installation of compensation metering equipment, or by 2.34% if metering equipment is not compensated.

The Company may also, at its option, install metering equipment on the primary side of the transformer for a Secondary Voltage Customer. In this case, the customer's metered demand and energy shall be decreased by 2.29%, or alternatively, compensation metering may be installed.

Issued April 25 2023
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Month Day Year

By Darrin Ives, Vice President

23-EKCE-775-RTS
Approved JG
Kansas Corporation Commission
November 21, 2023
/s/ Lynn Retz

Schedule KM-2

Index ____________

THE STATE CORPORATION COMMISSION OF KANSAS

EVERGY METRO, INC., d.b.a. EVERGY KANSAS METRO
(Name of Issuing Utility)

EVERGY KANSAS METRO RATE AREA
(Territory to which schedule is applicable)

SCHEDULE LGS

Replacing Schedule LGS Sheet 9

which was filed November 24, 2020

No supplement or separate understanding shall modify the tariff as shown hereon.

LARGE GENERAL SERVICE
Schedule LGS

For substation voltage customers metered at primary or secondary voltage level, the metered demand and

energy shall be increased by 1.20% (metered at primary voltage) or 3.56% (metered at secondary voltage), or alternatively, compensation metering may be installed.

For transmission voltage customers metered at substation, primary, or secondary voltage level, the metered demand and energy shall be increased by 0.90% (metered at substation voltage), 2.11% (metered at primary voltage), or 4.50% (metered at secondary voltage), or alternatively, compensation metering may be installed.

SERVICE AT TRANSMISSION VOLTAGE

When a customer receives service at transmission voltage through a lease arrangement (or another type of arrangement where financial responsibility is assumed), then additional applicable terms and conditions shall be covered in the lease agreement (or financial responsibility arrangement).

ADJUSTMENTS AND SURCHARGES

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS

Subject to Rules and Regulations filed with the State Regulatory Commission.

Issued April 25 2023
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Month Day Year

By
Darrin Ives, Vice President

23-EKCE-775-RTS
Approved JG
Kansas Corporation Commission
November 21, 2023
/s/ Lynn Retz

Certificate of Service

I hereby certify that a copy of the foregoing was served by electronic mail the 6th day of June 2025 to the parties below:

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