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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2026-0143

REBUTTAL TESTIMONY

OF

GRAHAM A. JAYNES

ON BEHALF OF

EVERGY MISSOURI METRO

Kansas City, Missouri
August 2026

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GRAHAM A. JAYNES

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I. Introduction

Q. Please state your name and business address.

A. Graham A. Jaynes. My business address is 1200 Main, Kansas City, Missouri 64105.

Q. By whom and in what capacity are you employed?

A. I am employed by Evergy Metro, Inc. and serve as Manager - Regulatory Affairs for Evergy Metro, Inc. d/b/a as Evergy Missouri Metro ("EMM"), Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("EMW" or "Company"), Evergy Metro, Inc. d/b/a Evergy Kansas Metro ("EKM"), and Evergy Kansas Central, Inc. and Evergy South, Inc., collectively d/b/a as Evergy Kansas Central ("EKC") the operating utilities of Evergy, Inc.

Q. Are you the same Graham A. Jaynes who previously filed direct testimony in this case?

A. Yes.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of EMM ("Evergy" or the "Company").

II. Purpose and Summary

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to respond to the normalization of test year revenues as proposed by MPSC Staff as well as the Class Cost of Service (CCOS), rate design, and revenue allocation recommendations from MPSC Staff, OPC, Google, and MECG.

Q. Can you summarize the rebuttal position related to rate design?

A. Staff generally supports restructuring Evergy Missouri Metro's non-residential non-lighting rates, but recommends delaying implementation until November 1, 2027, proposes a new Critical Peak Rate, and recommends modifications related to large load treatment and LLPS tariff provisions. My testimony explains why these departures from the Company's proposal are unsupported, introduce unnecessary risk, and should be rejected or substantially modified.

Q. What is your primary concern with Staff's recommendations?

A. Staff's recommendations move away from the Company's integrated rate design proposal without demonstrating that the modifications produce superior customer outcomes, more accurate cost recovery, more reliable implementation, or more meaningful price signals. In several areas, Staff's own report identifies uncertainty, system complexity, and verification limitations, yet Staff still recommends substantial changes to the Company's proposal.

III. Normalization of Retail Revenues

Q. Has Staff identified a billing issue that warrants correction?

A. Yes. Staff identified a billing-related issue limited to one lighting component impacting one customer. Billing system configuration is complete and now bills correctly. The Company has reviewed the concern and agrees that a correction is appropriate. In Company true-up detail an adjustment will be included to gross up revenue for the approximate $125,000.

Q. Is there a substantive disagreement between Staff and the Company regarding this issue?

A. No. This matter is administrative in nature. The Company agrees the identified billing issue should be corrected in the test year.

Q. What is the appropriate resolution?

A. The Company's position is that Staff's correction is reasonable, and the Company will include an adjustment as part of the true-up filing to address this correction.

Q. Do you agree with the general purpose of Staff witness Kim Cox's revenue normalization and annualization adjustments?

A. Yes. The Company agrees that retail revenues and billing determinants should be normalized and annualized to reflect known and measurable conditions expected to exist when rates are in effect. The adjustments discussed by Kim Cox, including weather normalization, 365-day adjustments, customer growth, and other annualization factors, are consistent with the Company’s approach in this case.

Q. Does the Company agree with all of Staff's normalized revenue results?

A. Not entirely. While the Company generally agrees with Staff’s approach, differences remain regarding certain calculation factors driven by application and timing assumptions as discussed by Company witness Al Bass.

Q. How should the remaining differences between Staff's calculations and the Company's calculations be resolved?

A. The Company believes the most appropriate resolution is through the true-up process. As additional actual data becomes available, the parties will have the opportunity to update normalization and annualization factors and reconcile timing differences. The Company expects that many of the remaining variances between Staff's calculations and those presented by Al Bass can be addressed using the most current information available at true-up.

Q. Does the Large Power annualization of Staff witness Rucker fit this same characterization?

A. In principle, yes. In practice, the Company believes that Customer B, the Large Power Service customer, should be annualized given known and measurable information as of the true up date and not included in the Staff True-up plug as proposed. Customer B should be treated as an existing LPS customer for normalization purposes in this case, based on actual known activity through true-up. Prospective expansion that could eventually implicate LLPS should not be incorporated until the applicable service request, infrastructure arrangements, tariff eligibility, and ESA obligations exist.

<u>Large Load Revenue Should Be Based on Known and Measurable Information</u>

Q. What does Staff acknowledge about the reliability of CCOS analysis in this case?

A. Staff acknowledges that it did not perform a CCOS study and asserts that it is not feasible in this case to conduct a reliable CCOS study due to class restructuring and the incorporation of new load, capacity requirements, and revenue associated with large customers. Staff further states that a CCOS study is only as reliable as the data it evaluates. Company witness Brad Lutz offers more perspective on the Staff position in his rebuttal.

Q. Why is that acknowledgment important for large load revenue treatment?

A. It confirms that the usage profile of new large load customers is a central uncertainty. If actual usage profile information is not available, then assumptions about load factor, activity, energy, or coincident demand are inherently less reliable than known contractual minimum billing obligations. Staff's own testimony recognizes that a useful CCOS study is not possible without information concerning the new load's usage profile.

Q. What should the Commission rely on instead?

A. The Commission should rely on known and measurable information, including contractual minimum bill levels, known activity as of true-up, or other known and measurable usage characteristics rather than assumptions about future operations for customers whose actual operating characteristics are not yet known. This approach avoids overstating revenues based on speculative load factor and usage assumptions for a developing customer class.

Q. How should Staff's large load adjustment be evaluated?

A. Staff's true-up plug should not be considered as indicative of a final known and measurable position but rather as a plausible placeholder that is moderately inflated.

Q. What assumptions did Staff use to annualize Customer A revenue?

A. Staff assumed a peak of ***[redacted]*** at a ***[redacted]*** load factor.

Q. Were these plausible assumptions?

A. Yes however speculative, as without materialized activity it stands as only expectations. Again, plausible is not the same as known and measurable.

Q. Do you support the load that Staff assessed for Customer A?

A. As a placeholder for actual activity, yes, but only to the extent that actual activity known and measurable at the true-up date would revise this adjustment to an accurate level.

Q. What assumptions did Staff use to annualize Customer B revenue?

A. Staff assumed Customer B would achieve a peak of ***[redacted]*** and a load factor of ***[redacted]***. While ***[redacted]*** is a level servable at the site today, it is anchoring expectations at the highest deliverable level.[1]

Q. Did Staff cite public statements by Customer B?

A. Yes. ***[redacted]***

Q. Why is this problematic?

A. While Staff settled on using load expectations provided by the Company via DR 226 to forecast Customer B activity, the inclusion of public statements appears to convey a level of confidence in the position by anchoring high expectations. Public statements are not a substitute for verified billing determinants, executed service obligations, or known and measurable usage data.

Q. Were these plausible assumptions?

A. Yes, although plausible is not the same as known and measurable.

Q. Do you support the load that Staff assessed for Customer B?

A. No. ***[redacted]*** peak as Staff has assumed has neither been demonstrated as a trend nor even in a single instance. While it could be a plausible load that Customer B may strive for and the Company may expect, it is not known and measurable.

Q. Why would Customer B differ from Customer A?

A. Customer B is a customer served under Large Power Service without LLPS requirements that provide protection in the case of Customer A. Customer B while a data center is

[1] As stated in response to data request MPSC-0226.

significantly different in size and characteristics. As no minimum bill and contracted demand amounts exist, the lack of demonstrated load presents a materially different circumstance. Please see the Rebuttal Testimony of Brad Lutz for more about the status of Customer A.

Q. What do you recommend?

A. Customer B annualization consistent with other LPS customer historical treatment. The Company proposes taking 12 months of known activity as of the true-up date.

Q. Do you otherwise agree with Staff's LLPS true-up plug?

A. No. In addition to the LLPS ramp levels discussed already, Staff applied a 3.64% increase in its calculation of the overall case Revenue Requirement. Staff's presentation of the increase masks an important distinction. Rather than first determining the final revenue requirement increase and then applying that increase uniformly across customer classes, Staff reduced the revenue requirement to be recovered through general rates by incorporating projected revenues from proposed large load customers under the LLPS tariff. As a result, Staff's recommended revenue requirement reflects a net figure after giving credit for the increase from this case to the current LLPS rates.

While Staff's methodology may mathematically keep the utility and customers whole, it changes how the case is presented. The effect makes the requested increase appear smaller by reducing the revenue requirement with revenues attributable to customers whose future rates are not yet known and measurable.

Q. Why is this problematic?

A. My concern is not primarily mathematic; it is conceptual and procedural. Traditionally, a rate case first establishes the utility's revenue requirement based on known and measurable costs and revenues. The Commission then determines how that revenue requirement should be distributed among customer classes through cost allocation and rate design, setting the new rates to recover the new requirement. Staff's approach effectively merges those two steps by embedding projected future LLPS revenues into the revenue requirement determination itself. In doing so, Staff uses expectations regarding future large-load customer rates to reduce the amount recovered from existing customers before the Commission has addressed the separate question of how costs and revenues should be allocated among classes. This reverses the normal analytical sequence and creates the optical illusion that the underlying revenue requirement is smaller than it actually is.

Q. Is there justification for taking this novel approach?

A. I understand this was done to provide clarity to the totality of LLPS impact. While well intentioned, it is not proven as a necessary deviation from the traditional ratemaking process.

Q. Is there a limiting principle for this LLPS treatment?

A. No. Staff’s reasoning could be taken to the logical conclusion and be applied to any/all other rate class. The result of which would be pro-forma revenue adjustments on all class revenue of 3.64% and a final revenue requirement of $0. If this is not a reasonable outcome, then neither can the application of this approach to a single class. Inherently this erodes the concept of a revenue requirement and undermines all stakeholders’ ability to understand the facts of the matter and the context of intervenor positions.

Q. Do you support this approach?

A. No. I do not find it necessary, and the approach introduces more elements to potentially confuse the traditional distinction between revenue requirement and rate design. Revenue requirement answers the question, "How much revenue must the utility collect?" Rate design answers the separate question, "Who should provide that revenue?" Staff's adjustment uses projected LLPS future rates from this case to answer part of the second question while still performing the first. Even if the resulting mathematics balance, the approach effectively imports a rate design outcome into the revenue requirement calculation and understates the magnitude of the underlying revenue requirement adjustment being considered by the Commission.

Q. How should this be resolved?

A. Staff should remove completely the 3.64% within the true-up plug, allow the revenue requirement to be stated without that adjustment, then apply the resulting revenue requirement across all classes. While resulting rates should be the same among both approaches, this traditional treatment preserves the facts of what revenue requirement is needed then adjusts rates appropriately.

IV. Class Cost of Service and Rate Design

<u>Review of CCOS</u>

Q. Do you agree with Staff's assertion "Conducting a reliable Class Cost of Service Study is not feasible"?

A. No. As I described earlier in my testimony, there are meaningful uncertainties associated with new large loads and the Company is proposing meaningful changes to its non-residential rate classes. And those uncertainties will impact the results of a class cost of service study (CCOSS). However, the Commission should not "throw the baby out with the bath water" because of this uncertainty. In fact, the Company provided two versions of the CCOSS, one version before the non-residential rate reclassifications and one version after. These are instructive studies that assess whether there are any identifiable changes since the Company's last rate case that should inform rate design or cost allocation changes. Please see the Rebuttal Testimony of Brad Lutz for more information concerning the benefit of CCOSS to the Commission. Ultimately, the Company's recommendation in this case is to apply the rate increase equally to all customer classes and part of that recommendation was based on the stability of CCOSS outcomes from prior cases into this case.

Q. Is Staff's feasibility concern applied consistently?

A. No. Staff's position is not applied consistently. Although Staff asserts that a reliable CCOS study is not feasible, Staff nevertheless relies on a 26-page functionalized cost-of-service analysis in its Rate Design Report Schedule 3 and develops LLPS annualization determinants using assumed load profiles. Those applications demonstrate that Staff continues to rely on analytical judgments in areas affected by the same uncertainties it cites as a basis for discounting the Company's CCOSS.

Q. Did any other party submit a Class Cost of Service Study?

A. No. OPC filed testimony with criticisms of certain aspects of the Company's CCOSS, namely suggesting that the allocator for production and transmission plant should be changed.

Q. Please describe how the Company allocates production and transmission plant in its CCOSS.

A. The Company allocates both production plant and transmission plant using the Average and Excess Demand method incorporating a four coincident peak component — the A&E 4-CP method. The average component reflects each class's average annual load; the excess component reflects the difference between a class's average load and its load during the Company's four highest system coincident-peak hours; the two components are weighted by the system load factor and combined. Production plant is the single largest cost component in the study, and the Company has used the A&E 4-CP method to allocate it consistently since 2018.

Q. What does OPC propose instead?

A. Witness Nelson, on behalf of OPC, proposes to discard the A&E 4-CP method and allocate both production and transmission plant using a Probability of Dispatch ("POD"), method. In broad terms, POD allocates each generating unit's revenue requirement across the 8,760 hours of the year in proportion to how much energy that unit produces in each hour, and then allocates each hour's cost to the classes in proportion to their load in that hour. Mr. Nelson reports that, relative to the A&E 4-CP method, his POD analysis would shift roughly 13.4 percentage points of production-cost responsibility away from the residential class — from 46.3% to 32.9% — and onto the Large General Service and Large Power Service classes.

Q. What standard should govern the allocation of production and transmission plant?

A. A class cost-of-service study should allocate costs to the classes that cause the costs to be incurred. Production and transmission plant are built, first and foremost, to serve the system's peak demand reliably, with enough margin to cover generator outages, weather extremes, and load-forecast error. Under cost causation, those demand-related costs should be allocated on the basis of the classes' contributions to the peak conditions that drive the investment. That is exactly what the A&E 4-CP method does, and it is the principle against which OPC's proposal should be measured.

Q. How does witness Nelson characterize his recommended POD method?

A. Witness Nelson describes it as a "temporal" method, and he expressly frames it as a move away from demand-based allocation. In his words, he advocates "the evolution of cost causation from a focus on demand allocators that focus on a few peaks, towards energy (or demand) allocators that more broadly reflect costs caused by load profiles," and he asserts that "costs are increasingly caused by energy use throughout the day and season, rather than a limited number of high demand hours."

Q. Is the POD allocation method akin to an energy allocator?

A. Yes, and the numbers confirm it. OPC's POD allocation factors land essentially on top of the energy allocation factors. The POD residential factor is 32.9% while the corresponding energy allocator in the Company's CCOSS is 34.0%. In other words, OPC's "temporal demand" result for the residential class is about one percentage point from a straight energy allocation (ignoring the residential POD allocator is curiously below its energy allocator). Therefore, 13.4-percentage shift witness Nelson proposes here is, in substance, the product of re-allocating capacity cost on energy. The table below compares the Company's energy allocator for each class with the POD allocator witness Nelson calculated in this case. As the table below shows, OPC's POD allocator is nearly identical to the Company's energy allocator for every class. The largest difference for any class is 1.1 percentage points, for the residential class, and for every other class the difference is 0.4 points or less.

Table 1 — Comparison of the Company's Energy Allocator and Mr. Nelson's POD Allocator

Customer Class	Energy Allocator	POD Allocator	Difference
Residential	34.0%	32.9%	−1.1%
SGS	8.1%	8.2%	+0.1%
MGS	13.6%	14.0%	+0.4%
LGS	24.1%	24.5%	+0.4%
LPS	19.6%	19.7%	+0.1%
Lighting	0.6%	0.5%	−0.1%
CCN	0.0%	0.2%	+0.2%
LLPS	0.0%	0.0%	0.0%
Total	**100.0%**	**100.0%**	**0.0%**

Q. Why is it improper to allocate production and transmission capacity on an energy basis?

A. As I stated above, energy consumption does not solely drive the investment. Two classes can consume the same annual energy while imposing very different capacity requirements. A method that allocates on hourly energy ignores that distinction. It also produces a perverse result for base-load plant: because a base-load unit runs in nearly every hour, POD spreads its cost across nearly every hour and therefore allocates it almost exactly as it would allocate energy, assigning that capacity investment a value approaching zero for the peak hours that also justified building it.

Q. Does the same concern apply to OPC's proposal to allocate transmission plant using POD?

A. Yes. The transmission system is designed and sized to move power reliably during peak-flow conditions; that is the engineering requirement that determines how much transmission plant must be built. Allocating transmission capacity on the basis of annual energy, as POD does, is disconnected from the peak-driven basis on which the system is actually planned and built.

Q. Is POD an established method for allocating embedded production and transmission cost?

A. No, and witness Nelson effectively acknowledges this. He concedes that the POD method has been "relatively rare historically," and the outside examples he cites are described in his own testimony only as methods "similar to" POD rather than as the same all-hours method he proposes here. The Company's A&E 4-CP method, by contrast, is well established, is named in Missouri statute, and has been used by the Company since 2018.

Q. Does OPC make an allocation proposal related to construction work in progress?

A. Yes. OPC witness Marke recommends that construction work in progress, or CWIP, be disallowed unless LLPS customers explicitly agree to bear all associated costs. To the extent CWIP is included in rate base, OPC further proposes allocating those costs entirely to LLPS customers.

Q. How did the Company allocate CWIP in this case?

A. The Company allocated CWIP consistently with other production-demand plant using the A&E 4-CP allocation method.

Q. Do you support OPC's proposed change in CWIP allocation?

A. No. While I understand the concern that costs associated with large-load growth should be assigned appropriately, OPC's proposal is not supported by the record in this case. The CWIP at issue has been allocated in the same manner as other production-demand plant, using the Company's established A&E 4-CP method. OPC's proposal would depart from that cost-allocation framework and assign all CWIP to LLPS customers even though the current case does not establish that those costs are caused solely by LLPS customers or that system dynamics have changed in a manner that warrants such a targeted allocation.

Q. Have you reviewed the Class Cost of Service Study analysis presented by MECG witness Jessica York?

A. Yes. I have reviewed Jessica York's testimony concerning the Company's Class Cost of Service Study, or CCOSS. Her review supports the Company's embedded cost-of-service framework, including the use of the A&E 4-CP method for production plant, the related treatment of transmission plant, and the new distinction between single-phase and three-phase primary distribution facilities. The Company appreciates that independent review and agrees that these methodologies reasonably reflect the cost-causation principles underlying the Company's CCOSS.

Q. Does the Company generally agree with Jessica York's interpretation of the CCOSS results

A. Yes. The Company agrees with Jessica York that the CCOSS identifies meaningful differences in the relative cost recovery of the customer classes and provides appropriate directional guidance for class revenue allocation. The Company also agrees with the principle that, over time, class revenues should move toward the costs identified by a sound CCOSS. In that respect, the Company and Jessica York are substantially aligned regarding both the interpretation of the study and the longer-term objective of improving alignment between class revenues and class cost responsibility.

Q. Does that agreement mean the Company supports applying Jessica York's class allocation recommendations in this case?

A. Not in their entirety at this time. The difference is principally one of application and timing, rather than interpretation of the CCOSS. Jessica York recommends class-specific increases that would move classes toward cost of service while recognizing gradualism. The Company agrees with that directional objective but believes the circumstances of this case warrant a more measured application of the CCOSS results.

As discussed in my direct testimony, no LLPS customer was active during the Test Year, the LLPS representation in the CCOSS is based on a proxy customer, and only fuel-related costs were assigned directly to the LLPS subclass. Actual LLPS demand, revenue, and cost responsibility are therefore not yet established through observed Test Year operations. Company witness Bradley Lutz explores issues if LLPS is not included in all respects further within his rebuttal testimony. The Company believes that caution is appropriate before making structural shifts in class revenue responsibility based on results that necessarily reflect this transitional treatment.

Q. Why is caution appropriate if the Company accepts the directional conclusions of the CCOSS?

A. A CCOSS is an important guide to class cost responsibility, but its results must be applied with informed judgment. In this case, the Company is simultaneously transitioning processes for the arrival of the new LLPS class and proposing changes that affect the composition and billing determinants of the commercial and industrial classes. The Company's direct testimony explains that actual LLPS coincident and non-coincident demands should be observed over a complete period before a comprehensive cost assignment is made. It also explains that customer movement and reactions to revised rate structures may affect the determinants used in future class allocation analyses.

Accordingly, the Company's caution should not be interpreted as disagreement with the CCOSS or with Jessica York's cost-causation analysis. It reflects sensitivity to the risk of implementing class revenue shifts before the operational data supporting the emerging LLPS subclass and the proposed class structure have matured.

Residential Customer Charge

Q. Please briefly describe the Company's residential customer charge proposal.

A. As I explained in my direct testimony, the current residential customer charge is $12.00 per month, and the Company proposes to increase it by $1.82, to $13.82 per month, an increase of 15.17% that matches the overall increase proposed for the residential class. Notably, the CCOSS shows that a purely cost-based residential customer charge would be $18.33 per month. The Company is deliberately not proposing to move all the way to that cost-based level; it proposes a gradual, step that maintains existing cost recovery proportions between residential fixed and volumetric charges.

Q. What do Staff and OPC recommend with respect to the residential customer charge?

A. Both recommend that the Commission reject the Company's increase and maintain the existing $12.00 monthly charge. In the Staff Rate Design Report, Staff estimates the cost of serving a residential customer at approximately $5.59 per month using a narrow "direct-connect" study that includes only an AMI meter, AMI meter maintenance, a service-line component, and a line-transformer component. OPC recommends retaining $12.00 on two grounds: first, that the Company's customer-related unit costs are "inflated" by its use of the minimum system method; and second, that increasing a fixed charge conflicts with

Missouri energy-efficiency policy and may disproportionately burden low-usage and low-income customers.

Q. Do you agree with the Staff calculation of customer charge.

A. No. Staff's $5.59 figure is not a competing class cost-of-service result; and is instead it is a truncated "direct-connect" calculation that captures only a subset of customer-related costs. By Staff's own description, it includes only the capital cost of an AMI meter (approximately $1.00 per month), AMI meter maintenance ($0.85), a service-line component ($2.01), and a line-transformer component ($1.72). Staff excludes the billing, payment-processing, and meter-reading costs on the theory that those functions are now obsolete. Staff's approach does not even touch on the customer-classified portion of the primary and secondary distribution system that the Company's CCOSS recognizes.

Q. Why is Staff's approach problematic?

A. Staff's approach is simply analyzing the classification of customer-related costs too narrowly. For instance, in a footnote, Staff asserts that "Historically, the customer charge would also include the costs associated with mailing bills, processing payments, and meter reading. These costs are generally obsolete with the introduction of new technology. Given that the cost of computer software does not fluctuate with the addition of new customers, it is not reasonable to include a prorated share of the related cost of service in the customer charge." These assumptions are inaccurate and imply that these billing and processing costs are energy- or demand-related costs, which is clearly not the case. If the costs are fixed, as Staff suggests, then those costs should be recovered though a fixed charge. Please see the Rebuttal Testimony of Brad Lutz for more on the problems with Staff's approach.

Q. Is the Company's analysis of customer costs more rigorous?

A. Yes. As I explained in my direct testimony, the Company's CCOSS follows the three-step framework that is standard in the industry and consistent with the National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual: functionalization of costs to production, transmission, distribution, and customer service; classification of those costs as demand-, energy-, or customer-related; and allocation of the classified costs to customer classes using factors derived from load research and system data. Customer-related costs are those incurred to extend service to and attach a customer to the distribution system, to meter the customer's usage, and to maintain the customer's account. These costs are largely a function of the number of customers served and continue to be incurred whether or not the customer uses any electricity.

Q. Without going through every line item, how significant are those customer-related costs that Staff ignores as "obsolete" or not applicable?

A. First, the Company's analysis relies entirely on per book embedded costs. So, while Staff estimated \$1.85 per month for metering, that estimate falls well short of the per books monthly metering cost of \$5.17. In addition, customer record keeping amounts to \$4.19 per month, uncollectible accounts amount to \$1.65 per month, and customer assistance amounts to \$2.09 per month. These four amounts total \$13.10 per month, without addressing costs for services, transformers, etc. It is plain that there are significant costs beyond Staff's narrow analysis and that the per book costs are a direct representation of the appropriate amount.

Q. OPC criticizes the minimum system method as based on an "unrealistic" hypothetical utility. How do you respond?

A. The criticism misses the purpose of the methodology. The minimum system method is a long-standing, widely used, and Commission-recognized method for separating the customer- and demand-related portions of distribution plant, and Mr. Nelson concedes that it is commonly used. His central objection, that if there were no demand the system would not be built and therefore no portion of the system can be customer-related. It is equally true that if there were no customers there would be no system at all. The distribution system exists to connect customers, and a real, irreducible minimum of plant, including the poles, conductors, service drops, transformers, and meters needed to attach a customer and make service available, must be installed to serve even the first unit of demand. That minimum is driven by the number and dispersion of customers rather than by the magnitude of any class's peak, and the minimum system method captures that customer-driven component.

Q. Does OPC advocate for a change to the Company's methodology?

A. Not in a meaningful way. Mr. Nelson expresses a preference for classifying fewer distribution costs as customer-related, but he does not demonstrate that the Company's methodology is inconsistent with accepted industry practice, nor does he present a Company-specific alternative study showing that the Company's results are unreasonable. Instead, his testimony largely reflects a policy preference for a different allocation of costs rather than evidence that the Company's methodology is flawed. In this case, the Company has made meaningful steps to refine cost allocation methodology as demonstrated via the single-phase split of primary distribution costs which was supported by MECG.

Q. Even if alternative methods exist, does that make the Company's use of the minimum system method unreasonable?

A. No. Cost classification is inherently a matter of informed judgment, and multiple accepted methodologies exist for classifying distribution costs. The relevant question is not whether another method could produce different results, but whether the Company's method is reasonable. The minimum system method has been used throughout the utility industry for decades, is recognized within the NARUC Cost Allocation Manual, and has been accepted in numerous regulatory proceedings. Mr. Nelson's testimony does not establish that the Company's method is unreasonable; it merely demonstrates that he would prefer a different approach, or more on point, a different outcome.

Q. Does increasing the customer charge undermine Missouri's energy-efficiency policy under the Missouri Energy Efficiency Investment Act ("MEEIA") as OPC states?

A. No. A $1.82 monthly increase does not meaningfully diminish any customer's incentive to pursue efficiency, and the Company's MEEIA portfolio continues to provide direct incentives for efficiency investment independent of rate design. Furthermore, the Company's proposal is to retain the relative proportion of cost recovery between fixed and volumetric rates. In contrast, Staff's and OPC's proposal would be to enhance the price signal to customers. However, the Company's proposal already strikes a balance because the proposed monthly charge of $13.82, well below the $18.33 per month of more narrowly defined customer-related costs and significantly below the full $41.18 per month of customer-related costs.

Q. Does a higher fixed charge disproportionately burden low-income and low-usage customers?

A. No. First, low usage is not the same as low income; and Mr. Nelson provides no evidence to correlate the two concepts. Because the Company proposes a below-cost customer charge, low-usage customers as a group are already subsidized through that charge, since they pay less than the cost they impose to be connected and served. Second, the objective of supporting low-income customers is better achieved through the portfolio of targeted assistance programs that the Company and Commission are implementing.

Q. Following OPC's concern of low-income or vulnerable customers, does increasing the proportion of costs to volumetric rates also increase risk to low-income or more economically vulnerable customers?

A Yes. Higher volumetric rates mean that whenever it is hotter than normal, then bills will increase by more as customers cool their homes. At some point in hotter weather, cooling the home becomes a matter of safety and therefore customers are unable to safely avoid a higher bill in those circumstances.

Q. Generally, are bill impacts more of a concern to low usage, low-income customers or high usage, low-income customers?

A. Electricity costs are by definition a greater proportion of income for high usage-low-income customers than low usage-low-income customers. Therefore, prioritizing low usage-low-income customers simultaneously creates more risk for a more vulnerable group of customers. This outcome highlights why the customer charge is a "blunt instrument" to implement what is perceived as something that will help a certain group of customers.

Q. What is your recommendation on the residential customer charge?

A. I recommend that the Commission approve the Company's proposed residential customer charge of $13.82 per month. It is supported by a standard, NARUC-consistent methodology; it is well below the amount supported by the Company's COSS; and it maintains the existing balance of cost recovery between fixed and volumetric charges.

Staff Non-Residential Rate Changes

Q. Have you reviewed Staff's Rate Design proposals?

A. Yes.

Q. Do these proposals contain only structural rate changes?

A. No. The proposals can be characterized as timing/implementation process proposals and structural rate design proposals. For this reason, I'll first discuss the structural changes and then address the implementation changes later in testimony.

Q. Does Staff oppose moving to 15-minute demand intervals?

A. No. Staff supports the move to 15-minute away from 30-minute demand intervals.

Q. Do you agree?

A. Yes.

Q. Does Staff oppose the Company's proposed movement away from the existing Hours Use structure?

A. No. Staff's report states that Staff supports the general rate structure proposed by EMM, although Staff recommends modifications most notably to the time windows.

Q. Does Staff oppose implementing C&I Demand Thresholds?

A. No. Staff supports the upper thresholds of 31, 250, and 3,000 KW for Small, Medium, and Large General Service respectively as proposed by the Company.

Q. Do Staff's proposed demand periods differ materially from the Company's proposal?

A. Yes. Staff proposes measuring billing demand over a very broad range of hours, extending from 10:00 a.m. to Midnight during summer months and from 6:00 a.m. to Midnight during non-summer months. By contrast, the Company's proposal focuses charges around a narrower set of hours intended to reflect periods when system conditions are most constrained. Broad windows tend to treat many hours similarly even though system conditions, customer behavior, and marginal costs can differ substantially throughout the day.

Q. Does a broader and more differentiated structure necessarily produce a better rate design?

A. Not necessarily. Rate design involves balancing economic precision with customer understanding and practicality. Additional periods, exceptions, and differing demand and energy windows may increase complexity without producing commensurate customer benefits. In my view, the Company's proposal achieves an appropriate balance by providing meaningful price signals through a more straightforward structure.

Q. Why is it important to maintain consistent Demand and Energy On-Peak period windows that are more narrow in applicable hours?

A. As proposed in EMM’s Direct, the peak periods were developed with several key objectives, with two of them applying on this topic. A well-defined peak period provides customers with a clear opportunity to reduce usage during the most expensive hours, thereby lowering their bills and contributing to system efficiency, and a well-defined peak period improves customer understanding and strengthens behavioral response. Maintaining consistent Demand and Energy On-Peak period windows for the Summer season will improve customer understanding for maximum benefit of reducing usage during On-Peak hours, and by narrowing the On-Peak hours, it will further provide an opportunity to shift usage.

Q. Does the Company have any other concerns with Staff's proposed Energy period windows?

A. Yes, the Company has concerns with the different time windows for Summer and Winter in which customers receive a credit and that during the Winter season, there will be 2 separate windows where customers will receive an additional charge. The Company believes that these aspects lead to a more complex rate when compared to the rate proposed by the Company and will harm the understandability for customers. The Company also believes an On-Peak period for Energy is not necessary for Winter because costs are not driven by generation capacity costs.

Q. What would you recommend instead?

A. I recommend the Commission adopt the Company's proposed time windows. The Company's approach provides a more balanced rate design by maintaining consistent and easily understandable periods for demand and energy pricing while still conveying meaningful cost-based price signals. The proposal creates a clearer distinction between peak and off-peak usage, reduces unnecessary complexity, and improves customers' ability to understand and respond to the rates. Staff's proposal, by contrast, relies on broader and differing demand and energy periods that add complexity without a corresponding demonstration of customer or system benefit.

Q. Does the lack of discussion on pricing imply support for Staff's proposed pricing?

A. No. The Company continues to support the pricing proposed in its direct testimony. If the Commission adopts structural modifications to the Company's proposal, the resulting pricing implications should be evaluated in conjunction with those structural changes, and the Company may address those implications in surrebuttal testimony.

<u>Optional Time of Use Should be Preserved</u>

Q. Does Staff discuss a high-differential non-residential rate?

A. Yes. In Staff's Rate Design Report Staff states "Staff does not recommend creation of highly-differentiated time-based non-residential rate schedules at this time."

Q. Is it clear that this is opposition to the Optional TOU introduced by the Company?

A. No. Evergy asked for clarification in data request 0484 to which Staff objected providing no clarification. In Part, 0484 asked:

> "1. Staff does not recommend " Highly differentiated time-based non-residential rate schedules". Is this a reference to Option 6 "Optional TOU" rate proposed by the Company?
>
> a. If not, please clarify.
>
> b. If so, please provide a narrative description of Staff's opposition."

Q. Why is Staff's opposition to the optional TOU offering problematic?

A. If Staff supports improved price signals and supports moving away from the existing Hours Use structure, then rejecting a voluntary option that provides stronger price signals requires evidence that the option harms customers or the system. The Company's proposal makes the TOU structure optional, which mitigates the risk of imposing it on customers that cannot respond while preserving customer choice for those that can.

Q. Why should the opt-in TOU option be preserved?

A. The opt-in TOU energy plus partial on-peak demand design provides stronger energy and demand price signals for customers who are capable of responding. Because it is optional, it allows interested customers to manage usage and potentially reduce bills without forcing that structure on customers that lack operational flexibility. A compelling point is that customers want this rate. As explained in my Direct Testimony, this design is the result of an extensive collaboration with non-Residential customers and is supported in this case by MECG.

Staff's One-Year Delay

Q. When does Staff want to implement the rate design changes?

A. Staff proposes delaying implementation until November 1, 2027.

Q. What is your position on Staff's delayed implementation proposal?

A. The Commission should reject Staff's proposal and approve the Company's implementation of both revenue requirement and rate design in accordance with the Direct testimony at the resolution of this case. Staff converts ordinary implementation contingencies into support for a fixed one-year delay without establishing that the Company cannot implement its filed proposal, quantifying a customer benefit, or identifying a decision that depends on the proposed reporting.

Q. Why is Staff's proposed one-year delay problematic?

A. Staff's proposed delay would leave customers on the existing structure for another year even though Staff supports moving away from that structure. That delays the benefits of clearer price signals, improved class homogeneity, and reduced opportunities for uneconomic rate selection that the Company's proposal was designed to address. The Staff

Report describes the Company's demand thresholds as intended to address uneconomic rate selection, mitigate opportunistic rate switching, and improve class homogeneity for future jurisdictional alignment.

Q. Does Staff quantify the benefit of a one-year delay?

A. No. Staff identifies general areas of work including customer education, rate calculation, and billing system preparation although does not show a quantified customer benefit from delaying restructuring until November 1, 2027. Staff's reliance on general implementation concerns is not the same as demonstrating that customers are better served by delaying the rate structure change for a full year. Staff identifies potential objectives, but does not quantify benefits, demonstrate necessity, or show that a one-year delay is the least-cost means of achieving those objectives.

Q. What risk is introduced by delaying the restructuring?

A. Delay introduces several risks:

1. Continued use of a rate structure being replaced.
2. Continued distorted price signals.
3. Continued potential for uneconomic rate selection.
4. Customer confusion from two sequential changes instead of one.
5. Loss of near-term opportunity to provide customers with clearer demand and energy pricing structure.
6. Administrative costs around reporting requirements and program expectations yet to be defined.

Q. What does Staff offer as support for the one-year delay?

A. Staff cites Company responses to MPSC data requests 0238 and 0239 relating to customer education plans and billing system configuration. Additionally, Staff references "…customers to begin to facilitate preparations for actions or equipment changes that will be economically efficient under the rates which will be taking effect in November of 2027". I will address the latter latent benefit later in testimony.

Q. Do you agree with Staff's characterization of Evergy's responses to Staff Data Requests 0238 and 0239?

A. No. Staff states that its recommendation to stagger implementation of the rate increase and the non-residential rate restructuring is "consistent with the delays anticipated" in Evergy's responses to Staff Data Requests 0238 and 0239. That characterization overstates Evergy's response. Evergy did not state that its proposed rate restructuring requires a one-year delay. Rather, Evergy explained that it had already evaluated whether its proposed rate designs could be configured and billed, had begun planning and preliminary configuration for the components included in the Company's proposal, and performs that configuration and testing in a dedicated test environment before promoting changes to production.

Q. What did Evergy actually say about implementation timing?

A. Evergy stated that its ability to implement restructured rates within ten calendar days depends on the complexity and scope of the Commission's final order. Importantly, Evergy stated that "[i]f rates are ordered as proposed and without unforeseen changes then the ten calendar days is acceptable." Evergy also noted that unexpected changes or additions may increase the work required for configuration, testing, and validation. That is a prudent implementation caveat, not support for a one-year delay of the Company's proposed restructuring.

Q. Why is Staff's representation concerning?

A. Staff uses Evergy's ordinary caveat about unforeseen Commission-ordered changes to make the need for delay appear greater than it is. The only meaningful billing-system surprise would occur if the Commission ordered a novel rate design, new rate element, or material modification that had not been part of the Company's filed proposal and therefore had not been configured and tested with forewarning. Staff's proposed delay should not be justified by transforming Evergy's caution about unexpected changes into a claim that Evergy cannot timely implement its own proposed restructuring.

Q. Does this assertion of billing shortcomings have other consequences?

A. Yes. Staff states "The Commission should also order EMM to test its billing system's ability to accurately bill the restructured rates, and to inform the Commission and the parties of any shortcomings or delays in its ability to bill through a filing in this docket.

Q. Is this a valid concern?

A. No. Staff's proposal unnecessarily amplifies ordinary billing-system implementation language into a broader concern about the Company's ability to implement its own proposal. That framing is not supported by the Company's response. Evergy's response describes standard and prudent implementation practices, including business requirements, test scripts, preliminary configuration, and use of a dedicated test environment. Staff then uses those ordinary safeguards to justify a one-year delay and additional reporting, even though the Company stated that ten calendar days is acceptable if the rates are ordered as proposed. Ordinary implementation safeguards do not support a one-year delay.

Q. Does Staff describe other activities necessitating a one year delay?

A. Yes, largely study and customer education. As stated in the Staff Rate Design Report: "Staff recommends that EMM inform its non-residential customers of the restructured rates and provide reasonable education to those customers. This should include a statement of the rate schedule the customer has been billed on, the rate schedule the customer will be billed on, simple and clear education concerning the time-based periods ordered in this case, an explanation of the recommended delay in restructuring until November 2027, and a one-time report of the following:

1. A statement of the total energy and 30-minute demand for 12 historic billing months,
2. A statement of the total energy, energy by time-based period, 15-minute NCP demand, and 15 minute on-peak demand for the same 12 historic billing months,
3. A calculation of the bill the customer would owe for the usage and demand for those 12 historic months on the increased non-restructured rates that are ordered in this case, and
4. A calculation of the bill the customer would owe for the usage and demand for those 12 historic months on the restructured rates that are ordered in this case and effectuate the rate increase."

Q. Is this a valid concern?

A. No. The Company performed reasonable bill impact calculations.

Q. How does Staff describe the 15-minute conversion?

A. Staff provides a demonstrative hypothetical customer that experiences a 13% increase in KW.

Q. Is this example demonstrative of expected change?

A. No. While theoretically it illustrates the concept, the expected change falls between approximately 2-4%. This difference is significant because the scale in practice is expected to be much less than the illustrated example.

Q. What alternatives could Staff propose?

A. Staff has failed to articulate the risk that the implementation delay is avoiding.

- If Staff is concerned about uncertain migration upward, pragmatic proposals could explore the migration criteria.
- If Staff is concerned with the 15-minute demand interval change increasing the number of customers migrating upwards, Staff could explore the threshold values.
- If Staff is concerned with understandability of the Hours Use replacement, Staff could propose simplified rates but instead their proposals introduce more varying time windows than that of the Company and build on new novel rate structures in the form of a CPR.
- If Staff is concerned with bill impacts, Staff could propose mitigating measures.

Q. Did Staff take any of these approaches?

A. No.

Q. Does Staff describe the evaluation of the proposed reporting or changes to be determined?

A. No. Staff only articulates a need to report. There is no action. The implication is that once impacts are identified in the report to Staff, then it is merely a wait to implement. There is no further evaluation of addressing Staff's concerns. This report in this form serves only as an administrative obstacle and not an actionable data point.

Q. Does Staff oppose removal of Reactive Demand for the MGS and LGS classes?

A. No, not in principle however Staff expresses the same need for study in relationship to other rate design changes to establish the appropriate restructured rates. For that reason Staff proposes maintaining the status- quo through the implementation delay.

Q. Is this a reasonable concern?

A. No. In addition to my concerns with the delay in this testimony, in my Direct Testimony I describe the minimal remaining Reactive Demand and the ease of removal. Staff inappropriately characterizes the complexity of the rate design proposals as a "catch-all" reason to bluntly delay implementation for unproductive study.

Q. Can you address the time for customers to adapt mentioned by Staff?

A. Yes, Staff asserts that the one-year delay allows time for customers to prepare for actions or equipment changes that would be economically efficient under new rates. This is speculative and undermines the effect of price signals. Staff's proposal reverses the normal function of price signals. Rates are intended to inform customer decisions. Staff would instead delay the price signal until after customers have had time to speculate about what changes may be economic under a rate structure that is not yet in effect.

Q. Can you summarize your concern?

A. Yes. Staff has manufactured a need for delay where none has been articulated and then proposed a delay in lieu of more pragmatic adjustments that would address any concerns. Delay is not neutral yet Staff only identifies speculative benefit. No consideration has been provided for cost/benefit of the delay or stated objectives beyond required reporting and assumed customer behavior change before price signals are realized.

V. <u>New Rate Design Proposals</u>

<u>OPC's Low Income Rate</u>

Q. What specific low-income rate design does OPC recommend?

A. OPC recommends an income-eligible rate design that would waive the residential customer charge for customers whose incomes are at or below 150% of the federal poverty line, or 60% of State Median Income depending on the metric adopted by the Missouri Department of Social Services. OPC states that this recommendation would apply to residential customers and is modeled on a threshold associated with LIHEAP eligibility and a Spire customer design.

Q. Is OPC's recommendation presented as a final, fully supported rate proposal?

A. No. OPC's own testimony characterizes the proposal as a "placeholder recommendation," "merely" a "starting point for discussions," and a recommendation that "will likely be modified in future testimony."

Q. What is the fundamental concern?

A. OPC is not proposing a studied rate design. OPC is offering an idea that develops presumably as stakeholder consensus arises within a rate case. The Commission should not convert an admitted placeholder into a tariffed rate without first requiring OPC to quantify the cost, determine cost recovery, evaluate alternatives, assess customer impacts, and resolve implementation issues.

Q. Are you opposed in totality to the concept of a Low Income Rate?

A. No. I am not opposed conceptually to the intent nor to entertaining customer charge modification, but it must be at the appropriate time with the appropriate cost benefit analysis. The Company is actively participating in workshops as part of Docket OW-2026-0085 and is interested in seeing the collaborative outcomes to ensure that next steps are aligned with the Commission perspectives. To introduce a concept mid case without study creates unnecessary exposure to unintended consequences and imprudent resource allocation. This should be evaluated in relationship to other programs. Company witness Katie R. McDonald provides rebuttal testimony discussing income-eligible programs.

Q. Has OPC quantified the annual cost of waiving the residential customer charge?

A. Not in the cited testimony. OPC recommends waiving the residential customer charge for income-eligible residential customers, but the testimony does not provide a participation estimate, an annual revenue impact, a cost-recovery mechanism, or a bill impact on non-participating customers.

Q. Using the current residential customer charge of $12 per month, what is the annual discount per participating customer?

A. Using the current residential customer charge, prior to any rate changes resulting from this case, the discount equals $12 per month * 12 months = $144 per participating customer per year. That means that for every 10,000 participating customers, $1.44 million of annual customer charge revenue must be recovered from other customers, offset by another rate component, or absorbed through some other mechanism.

Q. Why is this calculation important?

A. It shows that even a seemingly modest $12 monthly waiver can become a material revenue responsibility depending on enrollment. OPC's proposal cannot be evaluated by looking only at the bill reduction to participating customers. The Commission must also know the offsetting cost to non-participating residential customers, commercial customers, industrial customers, or any other funding source.

Q. Does OPC provide the number of customers who would qualify?

A. Not in the cited testimony. OPC identifies an eligibility threshold at or below 150% of the federal poverty level, or potentially 60% of State Median Income, and lists state-administered programs that operate at or below 150% of the federal poverty level, but it does not translate those eligibility categories into an estimate of eligible Evergy Metro residential accounts.

Q. Does OPC provide an expected participation rate?

A. No. OPC acknowledges the opposite problem: without additional action, enrollment "will be well below its potential" due to income-verification challenges, and OPC states that the current process is dependent on public or nonprofit entities because utilities do not want the liability and coordination of sensitive material. That admission means OPC has not solved the participation question needed to estimate program cost.

Q. Did OPC identify whether the waived customer charge would be recovered from other residential customers, other classes, shareholders, federal funds, or a separate rider?

A. Not in the cited testimony. OPC recommends waiving the residential customer charge and waiving late fees for eligible households, but the cited recommendation does not identify a specific cost-recovery mechanism for the lost customer-charge revenue or late-fee revenue.

Q. Does OPC's testimony show that a current, utility-specific energy burden analysis has been completed?

A. No. OPC states that Evergy Metro previously worked with stakeholders, including Renew Missouri, on input for Renew Missouri's Energy Burden web tool, but Geoff Marke says his review suggested that information had not been updated in at least a few years. OPC then separately recommends allocating no more than $150,000 for a third-party energy burden analysis throughout the Evergy Metro and Evergy West service territories.

Q. Why does OPC's proposed $150,000 third-party study matter?

A. It is an admission that the analysis needed to assess energy burden, targeting, and program design has not yet been completed. If OPC believes a third-party energy burden analysis is needed, then the Commission should require that analysis before approving a rate discount—not after.

Q. OPC separately proposed waiving the late fees for those eligible for this rate. Should this element be preserved?

A. No. Consistent with the concerns expressed before a comprehensive review would be necessary before support is merited.

Q. What should be studied before approval?

A. At minimum, a complete study should quantify: eligible customers by income threshold; expected participation under multiple enrollment scenarios; annual revenue loss; administrative costs; late-fee revenue impacts; effects on arrearages and disconnections; bill impacts on non-participants; distributional impacts across classes; interaction with

LIHEAP, weatherization, and arrearage programs; and whether a customer-charge waiver is more effective than alternatives.

Q. Can you summarize your opposition?

A. I oppose the rate as proposed by OPC. The proposal is a placeholder customer-charge waiver advanced before the Commission has completed its SB4 working docket, before rules have been finalized, before verification has been established, before costs have been quantified, and before alternatives have been compared. The Commission should reject OPC's proposal in this case and defer any rate creation until the appropriate due diligence has been brought forward in a future general rate case.

Staff's CPR Proposal

Q. Have you reviewed Staff's proposed Critical Peak Rate?

A. Yes. Company witness Bradley Lutz addresses Staff's proposed CPR from the operational and system-planning perspective, including whether the proposal is necessary, appropriate, and administratively workable. My testimony addresses the rate design implications of the proposal, including the claimed customer benefit, the behavioral response Staff assumes, and the customer and administrative risks associated with imposing a mandatory weather-event surcharge.

Q. What concern do you have with Staff's CPR proposal?

A. The CPR proposal creates a new mandatory surcharge during severe weather events without a demonstrated, quantifiable load-reduction benefit. Staff's own report states that the mechanism should not be treated as a MEEIA program because there is no reasonable or reliable way to quantify, evaluate, or verify avoided energy expense or avoided sales.

Q. Why does that matter?

A. If Staff cannot reasonably and reliably quantify, evaluate, or verify the energy expense avoided or sales avoided, it is difficult to conclude that the proposed CPR will produce benefits sufficient to justify the customer impact, operational complexity, communication burden, and weather-event surcharge optics. To enact a new surcharge without any due diligence balancing both costs and benefits would be unnecessarily risky and expose both the Company and customers to unintended/unforeseen adverse effects.

Q. What operational concerns does Staff identify with the six-hour CPR option?

A. Staff identifies several disadvantages of the six-hour option: the notice would need to specify the applicable hours, communications would be more complex, event hours could occur early in the day, information may not be available to customers until nearly midnight of the preceding day, detailed AMI reads would be necessary for billing, and estimating missing intervals based on prior usage would be inapplicable for a rate intended to induce usage changes.

Q. Why are weather-event surcharges especially concerning?

A. Staff states that the CPR should not cause deprivation, unhealthy living conditions for residential customers, or undue economic hardship for business customers. That statement recognizes the core concern: during severe weather, a portion of customer usage is not discretionary. A surcharge during those conditions risks charging customers more at the same time electricity may be most essential.

Q. Is Staff's CPR proposal superior to voluntary demand response or incentive-based alternatives?

A. The Staff excerpts reviewed do not demonstrate that Staff quantified the superiority of a mandatory CPR surcharge over voluntary demand response, a critical peak rebate, or other incentive-based alternatives. Evergy asked via DR 0477:

> 4. Has Staff evaluated the possibility that instituting a CPR could reduce the effect of voluntary curtailment rather than increase curtailment? If yes please provide Staff's conclusion and rationale.

Staff objected.

Q. Is it reasonable to assume that any surcharge, no matter the size, will increase curtailment?

A. No.

Q. Why is that not simply self-evident?

A. Because behavioral economics has repeatedly demonstrated that individuals do not always respond to small charges as classical economic theory would predict. Whether a surcharge changes behavior is an empirical question that requires evidence, not assumption. Staff has not identified any analysis demonstrating that the proposed CPR charges would result in measurable curtailment. Based on the excerpts reviewed, Staff appears to assume the existence of a behavioral response rather than demonstrate it.

Q. Are there examples where imposing a fee increased rather than decreased the targeted behavior?

A. Yes. One of the most frequently cited examples is the Israeli day-care center study by Gneezy and Rustichini (2000). Researchers found that introducing a small monetary penalty for parents arriving late to pick up their children increased late arrivals rather than reducing them. The authors concluded that the fee effectively transformed a social obligation into a market transaction, causing parents to view the behavior as something they could simply pay for.

Q. What relevance does that research have to Staff's CPR proposal?

A. The study illustrates why it cannot be assumed that any surcharge will produce the intended behavioral response. In some circumstances, a small charge may be viewed as the acceptable price of continuing the behavior. Here, Staff has not demonstrated that the proposed CPR charge will increase curtailment rather than simply become a fee some customers elect to pay while maintaining usage. Absent empirical support, the effect of the proposed surcharge remains speculative.

Q. **What do you propose related to the CPR?**

A. The CPR proposal should be rejected at this time. The lack of study and unsubstantiated benefit provides an incomplete and speculative foundation which is not adequate for a new mandatory surcharge. It risks introducing unstudied price signals for minimal to undetermined benefit at significant cost both to Company administration and customer experience.

VI. Revenue Allocation

Rebuttal to Google LLC

Q. Google witness Dr. Berry recommends that the Commission reject Evergy's proposed 15.19% increase to LLPS rates over the rates established in the 2025 LLPS Settlement. Do you agree?

A. No. Dr. Berry’s interpretation of the Settlement differs from the Company. As explained by Company witness Bradley Lutz, the negotiated LLPS rates were developed relative to the underlying LPS rate structure existing at the time of settlement, and the Settlement expressly requires comparison of LLPS revenues to the revenues the same customers would have paid under Schedule LPS. That comparison demonstrates that LPS serves as the benchmark against which LLPS pricing is evaluated. Company witness Bradley Lutz explains the development of LLPS pricing from the LPS baseline and the effect of the settlement adjustments. My testimony addresses the revenue-allocation consequence in this case.

Q. Why is that distinction important?

A. Because when base rates change in a general rate case, maintaining the pricing relationship contemplated by the Settlement requires that LLPS rates change as well. Otherwise, the relationship between LLPS and LPS would be distorted by future rate changes affecting only one schedule. Under Dr. Berry's interpretation, LLPS rates would become increasingly disconnected from the very benchmark they are built upon.

Q. Dr. Berry asserts that Evergy's proposal widens the gap between LLPS and LPS rates and would cause a hypothetical 300 MW customer to pay substantially more under LLPS. How do you respond?

A. Dr. Berry focuses on the size of the dollar difference between the schedules while overlooking why Schedule LLPS was created in the first place. Schedule LLPS is an intentionally unique tariff with distinct pricing and risk-allocation provisions for very large customers. As supported by Company witness Bradley Lutz, the Settlement did not establish that LLPS and LPS would produce equivalent bills. Rather, it established LLPS as a separate rate schedule whose pricing would be evaluated relative to LPS. Nothing in the settlement freezes future LLPS rates through subsequent general rate cases as substantiated by Bradley Lutz's discussion of Docket 25-EKCE-294-RTS in Evergy's Kansas Central jurisdiction.

Q. Is Evergy attempting to increase the premium that LLPS customers pay relative to LPS customers?

A. No. Evergy's proposal preserves the pricing relationship embodied in the Settlement. The Company's proposal reflects the same proportional relationship that existed when the parties negotiated initial LLPS pricing. What would actually alter the Settlement relationship would be increasing LPS rates while holding LLPS rates fixed. That outcome would erode the pricing differential negotiated by the parties and effectively rewrite the Settlement's initial pricing framework.

Q. How would you summarize these differences in perspectives?

A. Google's position preserves a number; Evergy's position preserves the relationship. The Settlement was not simply a schedule of prices. It established a pricing construct whereby LLPS charges are measured relative to LPS charges. When LPS rates change, maintaining the relationship requires LLPS rates to move as well. Until the time that cost causation can be fully assessed in a test year and CCOS, the Company's preservation approach is appropriate.

Rebuttal to Midwest Energy Consumers Group (MECG)

Q. Does MECG support the Company's proposed equal percentage increase across customer classes?

A. No. MECG disagrees with the Company's proposed equal percentage increase of approximately 15.19% across all customer classes. At this time, MECG does not provide a compelling argument for deviating from the Company's proposed equal percentage increase and the Company continues to support an equal percentage increase in this case because the CCOS results do not support a more targeted class revenue shift and because an equal percentage increase maintains rate stability while the Commission evaluates new large-load issues and the effects of non-residential class restructuring.

Q. Does MECG oppose the Company's proposed demand thresholds and 15-minute demand interval change?

A. No. MECG does not oppose the Company's proposed class-specific maximum demand thresholds for Small General Service, Medium General Service, and Large General Service, and it does not appear to oppose the movement from 30-minute to 15-minute demand intervals. That support is important because those components are central to the Company's broader effort to improve class homogeneity, reduce opportunities for uneconomic rate selection, and better align billing determinants with customer usage characteristics.

Q. Does MECG support eliminating the Hours Use structure for LGS and LPS customers at the conclusion of this case?

A. No. MECG recommends deferring or phasing the elimination of the Hours Use structure for LGS and LPS customers. The Company disagrees. The current Hours Use structure is one of the elements the Company's proposal is designed to replace, and delaying that change would preserve the same rate design limitations, classification concerns, and customer-selection issues that the restructuring is intended to address. The same rebuttal offered in opposition to Staff's proposal for delay is applicable here.

Q. How do you respond to MECG's concern regarding bill impacts for transition rate plan customers?

A. The Company recognizes that eliminating a legacy rate structure can produce varying bill impacts for individual customers, including customers currently served under the transition rate plan. However, the existence of individual bill impacts does not, by itself, justify retaining an outdated rate structure or delaying the broader restructuring. The appropriate question is whether the proposed structure better reflects cost causation, improves customer classification, and provides clearer price signals on a going-forward basis. The Company's proposal satisfies those objectives.

Q. Should the Commission require mitigation measures such as transition periods, bill caps, or targeted outreach?

A. The Commission should not require mitigation measures that would undermine the rate restructuring itself. Targeted customer education and outreach may be appropriate to help customers understand the changed structure, but bill caps or extended transition periods would blunt the intended price signals, preserve inequities embedded in the legacy rate design, and delay the movement toward rates that better reflect customers' usage characteristics and cost responsibility.

Q. Does MECG recommend changes to the allocation of the LPS class increase between demand and energy charges?

A. Yes. MECG recommends increasing demand charges by 1.5 times the class average increase assigned to LPS and increasing energy charges by 0.5 times the class average increase. The Company does not support that adjustment at this time. The Company's proposal provides a more balanced and integrated approach to implementing the overall rate increase.

Q. Do you have any response to MECG Witness York's concerns regarding the Company's optional TOU rate design?

A. Yes. MECG witness York raises several observations regarding the Company's optional TOU rate design, including seasonal energy-rate differences and voltage-differentiated demand and energy charges. With respect to the seasonal energy rates, the winter energy charges reflect the LMP information used in the Company's rate design and exceed the summer energy charges based on that underlying data. With respect to the voltage-related differences identified by MECG, the Company is continuing to evaluate those observations and may address them further in surrebuttal testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2026-0143

AFFIDAVIT OF GRAHAM A. JAYNES

STATE OF MISSOURI)
) **ss**
COUNTY OF JACKSON)

Graham A. Jaynes, being first duly sworn on his oath, states:

1. My name is Graham A. Jaynes. I work in Kansas City, Missouri and I am employed by Evergy Metro, Inc. as Manager – Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Evergy Missouri Metro consisting of forty-six (46) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

____
Graham A. Jaynes

Subscribed and sworn before me this 11th day of August 2026.

____
Notary Public

My commission expires: April 26, 2029

ANTHONY R WESTENKIRCHNER
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES APRIL 26, 2029
PLATTE COUNTY
COMMISSION #17279952

Evergy Metro, Inc. d/b/a Evergy Missouri Metro

Docket No.: ER-2026-0143
Date: August 11, 2026

HIGHLY CONFIDENTIAL INFORMATION

The following information is provided to the Missouri Public Service Commission under CONFIDENTIAL SEAL:

Document/Page	**Reason for Highly Confidentiality from List Below**
Jaynes Rebuttal, p. 5, ln. 13	9
Jaynes Rebuttal, p. 6, lns. 2-3; 6-7; 17	9

Rationale for the "confidential" designation pursuant to 20 CSR 4240-2.135 is documented below:

1. Customer-specific information;

2. Employee-sensitive personnel information;

3. Marketing analysis or other market-specific information relating to services offered in competition with others;

4. Marketing analysis or other market-specific information relating to goods or services purchased or acquired for use by a company in providing services to customers;

5. Reports, work papers, or other documentation related to work produced by internal or external auditors, consultants, or attorneys, except that total amounts billed by each external auditor, consultant, or attorney for services related to general rate proceedings shall always be public;

6. Strategies employed, to be employed, or under consideration in contract negotiations;

7. Relating to the security of a company's facilities; or

8. Concerning trade secrets, as defined in section 417.453, RSMo.

9. Other (specify): Protecive Order issued April 13, 2026.

Should any party challenge the Company's assertion of confidentiality with respect to the above information, the Company reserves the right to supplement the rationale contained herein with additional factual or legal information.