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Sarah L.K. Lange
Surrebuttal Testimony
File Nos. ER-2022-0129 & ER-2022-0130

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MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRIAL ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

SURREBUTTAL TESTIMONY

OF

SARAH L.K. LANGE

Evergy Metro, Inc., d/b/a Evergy Missouri Metro
Case No. ER-2022-0129

Evergy Missouri West, Inc., d/b/a Evergy Missouri West
Case No. ER-2022-0130

Jefferson City, Missouri
August 2022

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OF

SARAH L.K. LANGE

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Case No. ER-2022-0129

Evergy Missouri West, Inc., d/b/a Evergy Missouri West
Case No. ER-2022-0130

Q. Please state your name and business address.

A. My name is Sarah L.K. Lange, 200 Madison Street, Jefferson City, MO 65101.

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

A. I am employed by the Missouri Public Service Commission ("Commission") as an Economist for the Tariff/Rate Design Department, in the Industry Analysis Division.

EXECUTIVE SUMMARY

Q. What is the purpose of your surrebuttal testimony?

A. I will respond to certain rebuttal testimony of Evergy Metro ("EMM") and Evergy West ("EMW"), and also those of interveners related to class cost of service, revenue recovery allocations, rate design, and related issues, including current and future plans for Time of Use (ToU) rate structures at Evergy, and the retention of data necessary to evaluate current and potential rate structures and designs.

In this testimony, as described below, I revise my EMM revenue allocation recommendation. I also revise my residential customer charge recommendation for EMM and EMW to approximately $12.00.

DATA RETENTION

Q. Mr. Lutz expresses concern that certain data that Staff has requested EMM and EMW be ordered to retain "are data that does not generally exist within our record keeping in a manner that is readily available and usable for analysis."[1] Is this a reasonable reason to not require EMM and EMW to retain the data?

A. No. By the nature of the recommendation, the information Staff recommends be retained by EMM and EMW is information that EMM and EMW have represented that they do not currently retain. In general, the information sought by Staff facilitates reasonable allocation of revenue requirement to classes. Moreover, the information sought by Staff is necessary for review of the various rate structures Evergy states it intends to deploy, and for development of Staff counterproposals. There seems to be a consensus among Staff and Evergy that the electric industry continues to evolve both in terms of the costs utilities incur costs to serve customers and how customers will be billed. To accommodate these changes it is important for Staff to access information possessed by Evergy for those changing operating practices and rate base amounts, and it is important for Staff to have access to the customer information that can underlie development of modern rate structures Evergy has intimated are just on the horizon. Without this data, the chances for developing rates that impose unintended consequences on customers is higher and the risk of hindrance of the Commission's ability to appropriately establish just and reasonable rates to move the State of Missouri forward in the pricing of electricity are greater.

[1] Lutz rebuttal, EMW version, page 13.

Q. In your rebuttal testimony at pages 72 – 75 you contrasted Staff's energy rate design goals with Evergy's rate modernization plan, including at statement that "[t]he most reasonable path forward from Staff's perspective is:

1. adoption of voltage and infrastructure specific customer and facility charges for non-residential customers that vary with the customer's actual infrastructure and annual (or triennial) NCP, without regard to customer class,
2. transitioning of demand charges to the highest usage in a pre-established on-peak period, such as 6 am – 10 pm,
3. adoption of time-based energy rates without an hours use structure.

Could you contrast these steps with the criticisms of Staff's requested data retention measures made by Mr. Lutz at pages 13 – 21 of the EMM version of his rebuttal testimony, and with the Evergy rate modernization plan?

A. Yes. In short, the data Staff requests is generally necessary to price out unbundled revenue requirements for various elements of service that would either directly translate to rate elements under the Staff path, or translate into cost of service studies under the Evergy rate modernization plan. Mr. Lutz criticizes the requested data as "signal[ing] a troubling Staff position developing toward class cost of service and rate design work," and "as an attempt to reject standard practices and the industry standard in favor of hyper-detailed analysis," (Lutz rebuttal, EMM version, page 14). However, materials provided by Mr. Caisley[2] as the "STP Vision of Customer Experience Enhancement" state that the Objectives of the rate modernization plan are:

- Create rates independent of end use requirements
- Bring rate structures closer together across jurisdictions
- Enable business growth
- **Simplify rates and increase pricing transparency**
- Provide greater customer choice
- Increase customer satisfaction

[2] Caisley Direct, EMM version, page 16 of schedule CAC-1.

- **Leverage CIS and AMI infrastructure**
- **Develop price signals to increase grid efficiency**

[Emphasis added.]

Further, the "Drivers" indicated in Mr. Caisley's materials are:

- Multiple service territories in MO and KS
- Customers want choice
- **Implicitly promote beneficial electrification and grid benefits**
- **Proper price signals that enable adoption of emerging energy technologies that are most beneficial to the grid**
- **More equitable rates across diverging customer classes and subclasses**
- **Commission interest around time-of-use and distributed generation rates**

[Emphasis added.]

Each of the bolded objectives and drivers (and possibly some of the others) recognize the need for additional data, or for doing things differently going forward. In other words, Mr. Lutz in his surrebuttal argues that we should not change the information we rely on, while Mr. Caisley argues we need to completely rethink the utility rate structure paradigm. Mr. Lutz argues that we should stick with decades-old class-level cost allocation strategies, while Mr. Caisley argues a move towards equitable rates across classes and subclasses, with new and exciting rate design configurations. Mr. Lutz argues that additional data is just too difficult to get out of the new CIS system, while Mr. Caisley touts Evergy's version of rate modernization as utilizing the CIS and AMI systems. Mr. Caisley acknowledges that improved price signals will have an impact on grid efficiency, distributed generation, and other emerging technologies, but Mr. Lutz says we don't need any additional information (such as coincident peak bill determinants and customers by voltage) to set those price signals, and Mr. Lutz feels that requests for this data in the sole possession of the utility "border on minutiae."[3]

[3] Lutz rebuttal, EMM version, page 14.

Q. Is the development of the current EMM and EMW rate structures and rate elements relevant to understanding what information is necessary to reasonably study the current classes and design rates to the current rate structures?

A. Yes. The current EMW rate structures were driven by a push by Evergy over the last several years to align the EMW rate structure with the EMM rate structure. The current EMM rate structures were an outgrowth of a series of proceedings and detailed studies that occurred in the mid-1990s. Provided below is an excerpt from the section "General Description of the New Commercial & Industrial Tariff," of the document "Kansas City Power & Light Company Case No. EO-94-199 General Features of the Stipulated Rate Design," which was attached as Appendix A to the Order Approving Stipulation and Agreement in Case No. EO-94-0199, "In the Matter of the Customer Class Cost of Service and Comprehensive Rate Design Investigation of Kansas City Power & Light Company."

> Small General Service: This tariff was designed for the very small (under 25 kW) commercial and industrial customer. These customers typically have fairly low load factors.
>
> Medium General Service: This tariff was designed for the medium size (25 -200 kW) customer with a moderate load factor. Customers must have, or be willing to assume, a 25 kW minimum demand for service on this tariff.
>
> Large General Service: This tariff was designed for the large size (200 - 1000 kW) customer with a higher load factor. Customers must have, or be willing to assume, a 200 kW minimum demand for service on this tariff.
>
> Large Power Service: This tariff was designed for the largest size (1000+ kW) customer with a very high load factor. Customers must have, or be willing to assume, a 1000 kW minimum demand for service on this tariff.

The same document, at page 4, under the heading "Unbundled Charges," states,

> Charges on the new tariffs have been unbundled to better match the way in which costs are incurred with the way in which costs are recovered.

> Customer charges, which recover the costs associated with meter reading, billing, customer assistance, and facilities on the customers' premises, will be implemented for all customers. These charges will be specific to both the tariff and the customer's size.
>
> Facilities charges, which recover the costs associated with lines and transformers, will be implemented for all customers in excess of 25 kW. This charge will be based on each customer's annual maximum demand.
>
> Demand charges will be implemented for all but Small General Service customers.
>
> All tariffs will have energy charges based on the customer's hours use (monthly load factor. These charges, which recover time-of-use costs, provide price incentives to customers to improve their load factor.

Finally, that document, at page 4, under the heading "Voltage Level Distinctions," states,

> The General Service and Large Power tariffs recognize voltage level differences between customers.
>
> The levels of the facilities charge account for customer ownership of specific distribution equipment.
>
> The levels of the demand and energy charges reflect the differences in losses at various delivery voltage levels.
>
> If the customer's metering voltage differs from the delivery voltage, the metered demand and energy will be adjusted to reflect losses between the two voltage levels.

In other words, the contemplated differences between the classes are overall size of the customer, and a correlation drawn between usage characteristics of customers within a class and the cost of serving customers in that class. In fact, the reliance on an hours use rate structure was taken as a surrogate for costs that were known to vary by the time at which energy was consumed, and given customer characteristics at the time, it was assumed that increases in load factor would necessarily generate reductions in average cost of service to a given customer. Under today's market conditions, however, the lowest average cost of service would be to a customer with a poor load factor constituted of energy consumed in low-cost wholesale energy hours, which are generally hours in which the distribution and transmission systems are unconstrained, and are not peak-causing for purposes of generation capacity requirements.

Q. What information is necessary to study the reasonableness of rates with regard to the matters included under "Voltage Level Distinctions?"

A. The information necessary to review the reasonableness of charges designed to address these matters would include, but not be limited to, an average or representative level of facilities, and the revenue requirement associated with each level of facilities, for customers by class and within a class served at various voltage levels. Further, in allocating distribution costs to the classes, it is necessary to have a reasonable understanding of which plant items/costs are customer-specific, and which plant items/costs are devoted to network service of solely customers served at secondary voltage.

Q. What information is necessary to review the reasonableness of "Unbundled Charges?"

A. First, for customer charge rate elements, it is necessary to understand the facilities and related revenue requirement of an average or representative installation of metering equipment for customers by class and within a class at various voltage levels.

Second, for facilities charge elements, it is necessary to understand the facilities and related revenue requirement of an average or representative installation of service lines (or primary equivalent) and line transformers (or station equipment equivalent) for customers by class and within a class at various voltage levels.

Third, for demand charges it is necessary to move beyond the shortcut assumption in place in the mid-1990s that customer NCP and customer class were effective surrogates for understanding the requirements that a customer causes on distribution, transmission, and generation capacity. To the extent a demand charge remains a useful surrogate, the around-the-clock NCP approach should be replaced with the maximum customer demand within a window that is accepted as contributory to capacity requirements. In the absence of a pre-defined window for which such data would be retained, it would be reasonable to maintain robust samples of individual customer data which can be extrapolated to estimate the sum of this determinant, by month and annually, at rate code, class, and system levels.

Fourth, for energy charges, hourly load information at the rate code, class, and system level data is necessary to develop reasonable charge levels, and robust samples of individual customer data that can be extrapolated to estimate potential impacts or to troubleshoot the design are reasonable.

Q. Today, can Staff examine these relationships that were established in the 1990s, and can Staff draw upon current data to review Evergy's plans for rate modernization in upcoming cases?

A. Staff cannot review the relationships between voltages and among subclasses to a reasonable extent if Staff does not have access to data at a voltage and subclass level. Staff shares Evergy's interest in rate modernization, but unlike Evergy, Staff is unable to pull data as needed to evaluate whether a given determinant is the most reasonable determinant, or to evaluate how a given structure may change the bill of various customers. Staff's data retention recommendations are intended to capture the data that is most related to cost causation, some of which may eventually be used as the basis for a charge type, and some of which will be used only within the context of a CCOS Study. It is premature to know what data will be used for charge types, because Staff doesn't have access to data to understand how a given charge type would impact bill stability, revenue stability, or cause rate shock, or other factors that are considered in ultimately designing rates.

A modern class cost of service study encompasses significant offsetting revenues, and in that rates can be more closely aligned to determinants across classes given the advent of cost-effective advanced metering. Today, a customer's class is no longer the best tool for pricing a customer's energy. Historically, it was prohibitively expensive to meter and bill exactly how much energy each customer used at all times. Classes were used as a shortcut for setting rates, and class distinctions were based on annual demand and on end use. The general premise of a class is a simplifying assumption that customers within a class used energy similarly enough that they could be billed based on either the total usage in a month or the highest usage in an interval in a month, or a simple relationship of those amounts, without regard to the time of day that energy is actually consumed or the time of day at which a customer experienced its peak demand.

Grouping customers into classes based on more or less the average annual demand is no longer the best tool for aligning a customer's rates with their cost causation; with the advent of cost-effective AMI metering, billing customers by the energy they consume in a given interval is now capable of providing a more meaningful price signal than billing customers based on the rate schedule under which they are served. However, development of such rates requires access to hourly usage at the rate code level. Because many of these rate codes are defined by voltage, access to information at the level of operating voltage is also necessary.

Q. Mr. Lutz broadly categorizes Staff's recommended data retention as related to certain areas, and indicates that some are acceptable, and some are not. Could you summarize his conclusions?

A. Yes. Mr. Lutz at page 13 of the EMM version of his rebuttal testimony appears to accept Staff's recommended data retention for "Demand charge data" (Staff item #9), and

"Reactive demand data" (Staff item #10). However, at page 20 he clarifies that the Company will only accept "study" of the demand and reactive demand data that is already retained by the Company, and explicitly refuses to retain demand data or reactive demand data for classes not already billed by those elements. He recommends rejection of Staff's recommendation for retention of "Distribution data" (Staff item #1), "Billing/Metering data" (Staff items #2 through #7), and "Bill comparison data (Staff item #8)."

Q. Is Mr. Lutz's response concerning "Bill comparison data" (Staff items #8) reasonable?

A. No. At page 20, he argues that he finds Staff's recommended requirement for retention of "Bill comparison data" (Staff items #8) "odd[,] as customers currently have the ability to compare their rate plans. On the Company web site, after creating an online account, the customer may examine how their past usage would compare under other rate plans." He concludes that "[a]s bill comparison capabilities already exist, I suggest this recommendation be rejected."

Staff is aware of these current bill comparison capabilities, and its recommendations is that the Commission order that those capabilities remain available to customers.

Reactive Demand Data

Q. What information did Staff recommend be retained related to reactive demand and reactive power requirements and conditions?

A. Staff recommended that EMM and EMW begin to retain and study data related to the reactive demand requirements of each rate code, and sample customers within each rate code. While in recent history reactive demand has not been a determinant in CCOS studies or a rate element for many customers, emerging system conditions associated with changes in regional generation fleets may occasion further study of reactive demand requirements.

Q. What was Mr. Lutz's response to this request?

A. Mr. Lutz's represents at page 20 of his EMM testimony that "the Company will study only those rates where a reactive demand charge is part of the current design or a demand charge could be added without material configuration of customization of the Company metering or billing systems."

Q. Is the data Mr. Lutz offers to provide sufficient?

A. No, limiting the study to those rates with an existing reactive demand component is not adequate.

Q. Why is Staff interested in studying reactive demand in terms of a class cost of service study and in the furtherance of developing rate structures and designs?

A. As rotating mass generation – especially rotating mass generation located in close proximity to load – is retired, voltage collapse can result from reactive demand imbalances, which can cause blackouts. Given the prevalence of rotating mass generation – especially rotating mass generation located in close proximity to load – in the past generation fleet composition, this issue was relatively minor. Today, utilities across the Midwest are seriously considering deploying multimillion dollar Static Compensators (StatComs) or other infrastructure-intensive measures to stabilize the balance of reactive and real power. At the historic levels of rotational mass generation, reactive power issues tended to be hyper-local and related to large industrial loads, which could be addressed with deployment of capacitor banks or related devices. With the shrinking share of rotational mass generation in the Midwest, it is likely that a competent energy company would be collecting and retaining data concerning the reactive demand position of various portions of its distribution system. Issues that arise due to excessive reactive demand are likely to arise on a local level, so to the extent that infrastructure or other increases to revenue requirement are necessary to address a reactive demand issue, system-wide reactive demand determinant charges for those classes which currently have reactive demand charges will not be useful to either allocate the increased revenue requirement among classes, or to bill customers within classes.

Q. To clarify, is Staff suggesting that it may be necessary in the near term future to allocate revenue requirement to all classes on the basis of reactive demand?

A. Yes. To the extent that installation of StatComs or other infrastructure is necessary to provide voltage support in the absence of centrally-located rotating mass generation, reactive demand on the class level would be the obvious allocator to use in a future CCOS.

Q. To further clarify, is Staff suggesting that it may be appropriate in the near term to incorporate a discrete reactive demand charge to residential and SGS customer bills?

A. Yes, it is a possibility. Factors to consider will be the level of revenue requirement allocated to those classes on the basis of reactive power requirements and the uniformity (or lack thereof) of reactive power requirements within those classes. If the revenue requirement is low, and the intraclass-uniformity is high, a discrete charge would not be necessary. If the revenue requirement is high and the intraclass-uniformity is low, a discrete charge may be reasonable. The Staff recommended data retention would make such future determinations possible.

Q. What types of end-uses disproportionately require reactive power?

A. Reactive power is required in excess of apparent power in devices that induce magnetic fields, such as pumps and motors. Common appliances that require disproportionate reactive power include heat pumps, refrigeration equipment, and motors (including fans). Examples of end uses that typically do not draw disproportionate reactive power include heating elements such as those found in dryers or electric ranges, and electronics (excluding cooling components). Note, the transmission and distribution systems themselves operate in a manner that requires or provides reactive power, particularly in operation of transformers, and in the performance of the system in very high and very low loading positions.

Demand Data

Q. What data did Staff recommend be retained that Mr. Lutz characterizes as "Demand Data?"

A. Staff recommended that EMM and EMW be ordered to develop the determinants for assessment of an on-peak demand charge to replace the current monthly billing demand charge, and for potential implementation for customers not currently subject to a demand charge. At this time, Staff recommends that in summer months the period be noon – 10 pm, and during non-summer months the period be 6 am – 10 pm, but Staff welcomes the input of other parties to refine these time periods. Staff does not recommend that weekends and holidays be excluded.

Q. Why is Mr. Lutz's representation at page 20 of his EMM testimony that "the Company will study only those rates where…a demand charge could be added without material configuration of customization of the Company metering or billing systems," insufficient?

A. As I noted in my rebuttal testimony, Staff does not want and cannot accommodate 15 minute usage data for all residential (or SGS, or MGS, or LGS) customers. In the absence of that data, there is certain information that we must rely on the Company to extract from its billing system. In this case, we have been informed that the Company views such requests for information as requiring additional analysis that they will not perform. Staff intends to use the data for at least the following purposes:

1. Improved alignment of the revenue recovery and cost causation in the billing of demand charges for classes which currently rely on customer NCP demand charges,
2. Potential improved alignment of the revenue recovery and cost causation in the billing of revenue requirement associated with power supply and delivery capacity costs for classes that currently recover that revenue requirement through energy charges,
3. Potential development of allocators for distribution plant on the basis of diversified demand and related measures,
4. Potential implementation of modern rate structures as discussed above,
5. Review of the reasonableness of rates proposed by Evergy in their rate modernization efforts,
6. Development and refinement of rate schedules or revenue requirements for potential new rate schedules with novel designs, such as we have recently seen at EMW.

Q. Did Staff request other demand-related data that Mr. Lutz has characterized as "Bill Comparison" data?

A. Yes. I recommended that the Commission order EMM and EMW to retain data sufficient to provide to Staff upon request, "for rate codes with more than 100 customers, a sample of individual customer hourly data, and identified peak demands for those 100 customers in the form requested at that time (i.e. monthly 15 minute non-coincident, annual 1 hour coincident)" and, "for rate codes with 100 or fewer customers, individual customer hourly data, and identified peak demands for those customers in the form requested at that time (i.e. monthly 15 minute non-coincident, annual 1 hour coincident)."[4]

[4] See paragraph 8, page 4, Sarah Lange direct in EMM and EMW.

Q. Why is this information needed for all customers (or representative of all customers) if currently only a few classes have demand charges?

A. Currently, in CCOS studies, the demand determinants that are relied upon are the class peak usage in a given month or year, or the class's usage at the time of the system peak in a month or a year. However, within a class, for rate design purposes, the demand determinant that is used is a customer's peak usage in a given month or year, regardless of the time of the peak.

The amount of capacity and reserve a utility requires is determined by its annual system peak. Many transmission expenses are determined by monthly system peaks. However, the hour of peak cannot be known with certainty until after it is past and until the month or year have concluded. It would not be lawful to go back and bill customers for usage in that hour, and without knowing what the usage will be in that hour, we don't know what rate would need to be charged to recover those costs. Further, it is not uncommon for multiple hours to have similar usage. A given customer could have low usage in one potential peak hour, and high usage in another potential peak hour. Therefore, it is more reasonable to use a range of hours that are historically capable of being peak hours to measure peak customer determinants than it is to use the literal hour of system peak after-the-fact.

It is reasonable to gather this information for all customers even if all customers are not currently charged demand charges, because the sum of those determinants may be a useful allocator of costs at a class level, so that the same basis of costs is used to allocate costs to classes as is used to allocate costs to customers within a class.

Q. Does Staff anticipate designing residential rate structures with multiple demand charges?

A. No. At this time, Staff has essentially no customer-level demand data for the overwhelming number of customers.

Distribution Data

Q. What items are included in your distribution data retention recommendations?

A. Staff's distribution data retention recommendation, as found in my direct testimony on page 62 is, "Prior to the next rate case, the Company will identify and provide the data required to determine: line transformer costs and expenses by rate code; primary distribution costs and expenses by voltage; secondary distribution costs and expenses by voltage; primary voltage service drop costs and expenses; line extension costs, expenses, and contributions by rate code and voltage; and meter costs by voltage and rate code. If the required data is not readily available, the Commission should order Evergy to file an EO docket explaining why it cannot provide the data, and its individual estimate of the cost to provide each set of data described, for the further consideration of the parties and the Commission."

Q. Do you agree with Mr. Lutz that distribution data on this level was not required to allocate the capital costs of nuclear power plants in the 1980s?

A. That is correct. I am sure Mr. Lutz understands that distribution system data is more relevant to the allocation of distribution system costs than it is to the allocation of generation costs, so I assume he included this statement in error.

Q. Would you object to refinement of this item to reflect amperage or phase of service, or some other meter characteristic?

A. No. The intent of this requirement is to be able to align cost causation with revenue responsibility at the class and customer level. To the extent that a different characteristic than demand better or more readily facilitates that alignment, I support revision of this requirement accordingly so long as determinants associated with that characteristic are also made available and linkage within the customer billing system between customers and determinants is established in a reasonable timeframe.

Q. What is the purpose of the "distribution data" you have requested?

A. I will address each requirement below, separately.

Meter Costs by Voltage and Rate Code

Q. Why did you request meter costs by voltage and rate code?

A. Staff requests data concerning "meter costs by voltage and rate code," so that, within a CCOS Study, account 370 (meters) and any sub accounts, and related expenses can be allocated as reasonably as is practicable to the studied classes. Further it is sometimes appropriate to review the reasonableness of differing customer charges based on the metering capability a customer requires to serve its load.

Q. Has this or similar information been obtained from Evergy or other Missouri utilities in the past for purposes of CCOS Studies?

A. Yes. From time to time in the past, predecessors to EMM and EMW (and other utilities) have done detailed meter cost studies. It is my recollection that a detailed study was performed by EMM predecessor Kansas City Power & Light in the contest of a series of informal exchanges and proceedings spanning from 1994 – 1997. It is reasonable to periodically do such deep dive studies, data is necessary to do such studies, and the AMI rollout at both EMM and EMW are reasonable drivers of doing such a study. Performance of a study requires data, which may be either a representative sample, or may be comprehensive of virtually all customers. Sample data is likely sufficient to (1) determine the appropriate allocation of meter costs among classes in the context of a CCOS, and (2) to evaluate whether a different charges should be established within a class. More comprehensive data is needed to (3) review the reasonableness of existing differing charges within a class, and (4) to create new differing charges within a class.

Q. Is this information also relevant to rate design?

A. Yes. As alluded to in (2), (3), and (4) above, Staff requests this data to assess the reasonableness of customer and facility charges as they currently exist, and to review whether additional delineation is necessary or appropriate.

Q. Is this data relevant to existing rate structures and designs at Evergy?

A. Yes. For example, currently, an EMM Medium General Service customer served at secondary voltage with a maximum demand of 25 kW pays a customer charge of about $54 dollars, while an EMM Medium General Service customer served at secondary voltage with a maximum demand of 250 kW pays a customer charge of about $935. However, an EMM residential customer currently pays a customer charge of $11.47 whether they are a tenant in an apartment with a 120 volt meter experiencing a maximum demand of 15kW, sharing a single line transformer with 3 other tenants with identical infrastructure, or whether they are a group home with three phase service and a maximum demand of 500kW operating a commercial kitchen and substantial HVAC equipment. It may be that the meters for both customers are identical or very similar in design and the same or similar in average price, but in the absence of meaningful data, Staff cannot reach that conclusion. Moving from the potential creation of residential differentials to the existing differentials in non-residential classes, in the absence of meaningful data, Staff cannot evaluate whether the existing disparities within and between the non-residential classes are reasonable, nor meaningfully recommend their valuation in future cases.

The current customer charges for each class, for each demand level, are illustrated below:

EMM	SGS	MGS	LGS
0-24 KW	$ 18.18	$ 53.96	$ 118.82
25-199 KW	$ 50.40	$ 53.96	$ 118.82
200-999 KW	$ 102.38	$ 109.59	$ 118.82
1001+ KW	$ 874.15	$ 935.69	$ 1,014.44

Accepting that it is reasonable for MGS and LGS to include higher customer charges for customers with demand below the effective minimum demand for that class, there is no apparent cost-based reason for the misalignment that exists between the customer charges across classes. It would be reasonable to realign these charges for customers with similar meter costs regardless of class, but we currently do not have the information to determine an appropriate charge.

Q. Moving from rate design to rate modernization, and shifting focus to non-residential customers, what is the usefulness of the requested meter data?

A. For modern rates, the ability to bill a customer for the cost of the metering facilities installed as distinct from the existing customer class is a reasonable goal, and Staff recognizes that incorporating this data into the billing system will take time. It is our understanding the EMM and EMW do not currently have the ability to bill customers based on the customer's meter cost outside of the fact that a customer is currently receiving service in a given rate class.

<u>Line extension costs, expenses, and contributions by rate code and voltage, and primary voltage service drop costs and expenses</u>

Q. Why did you request line extension costs, expenses, and contributions by rate code and voltage?

A. Staff requests data concerning "line extension costs, expenses, and contributions by rate code and voltage," so that, within a CCOS Study, account 370 (meters), account 369 (services) account 368 (line transformers), account 367 (underground conductors and devices), account 366 (underground conduit), account 365 (overhead conductors and devices), account 364 (poles, towers, and transformers), and account 362 (station equipment) and any sub accounts, and related expenses can be allocated as reasonably as is practicable to the studied classes. This includes allocation of offsetting contributions from the relevant line extension policy.

Q. If a customer requesting to be served at primary voltage is located ¼ of a mile from existing primary distribution facilities, to what accounts will the ¼ mile of new primary conductors, poles, devices, and transformers required to serve that customer be recorded?

A. My understanding is that while these materials would be characterized as "services" if the customer is to be served at secondary voltage, in this example, these materials would be recorded to account 367 (underground conductors and devices), account 366 (underground conduit), account 365 (overhead conductors and devices), account 364 (poles, towers, and transformers), and account 362 (station equipment). These costs should be allocated exclusively to customers served at primary, rather than allocated as a portion of the primary distribution system.

Q. Is this consistent with industry best practices?

A. Yes. The RAP manual at page 156 states,

> 11.3.6 Direct Assignment of Distribution Plant Direct cost assignment may be appropriate for equipment required for particular customers, not shared with other classes, and not double-counted in class allocation of common costs. Examples include distribution-style poles that support streetlights and are not used by any other class; the same may be

> true for spans of conductor to those poles. **Short tap lines from a main primary voltage line to serve a single primary voltage customer's premises may be another example, as they are analogous to a secondary distribution service drop**. Beyond some limited situations, it is not practical or useful to determine which distribution equipment (such as lines and poles) was built for only one class or currently serves only one class and to ensure that the class is properly credited for not using the other distribution equipment jointly used by other classes in those locations.
> [Emphasis added.]

The RAP manual at page 142 acknowledges the common division of distribution costs into two categories,

> 'Share distribution,' and '**Customer-specific costs, which include: Service drops connecting a customer (or multiple customers in a building) to the common distribution system (a primary line, a line transformer or a secondary line or network**). • Meters, which measure each customer's energy use by month, TOU period or hour and sometimes by maximum demand in the month. Advanced meters can also provide other capabilities, including measurement of voltage, remote sensing of outages, and remote connection and disconnection. • Street lighting and signal equipment, which usually can be directly assigned to the corresponding rate classes. • In some systems with low customer spatial density, a significant portion of primary lines and transformers serving only one customer.
> [Emphasis added.]

Also, the NARUC Manual at page 87, footnote 1, states '**Assignment or 'exclusive use' costs are assigned directly to the customer class or group with exclusively uses such facilities**. The remaining costs are then classified to the respective cost components.' [Emphasis added.]

Q. Is study of these costs necessary beyond the CCOS use described above?

A. Yes. Greater information on these costs is needed to assess the reasonableness of existing facilities charge differences within non-residential rate codes, and to assess the reasonableness of existing excess facilities charges.

Line transformer costs and expenses by rate code

Q. Why did Staff request information related to line transformer costs and expenses by rate code?

A. Staff requests data concerning "line transformer costs and expenses by rate code" to better allocate these costs within a CCOS, and to review existing rate design disparities in facilities charges within customer classes. Staff would also like to review the reasonableness of incorporating differing levels of line transformer revenue requirement into customer charges for SGS and Residential customers, if there is a cost-basis to do so.

Secondary distribution costs and expenses by voltage

Q. Why did you request information related to secondary distribution costs and expenses by voltage?

A. Staff requests data concerning "secondary distribution costs and expenses by voltage" because, in general, secondary costs and expenses should not be allocated or assigned to customers served at primary voltages.

Q. How much of the infrastructure in account 367 (underground conductors and devices), account 366 (underground conduit), account 365 (overhead conductors and devices), and account 364 (poles, towers, and transformers) operates at a secondary voltage?

A. I don't know. Based on data request responses and conversations with the Company, the Company is unable to provide this information.

Q. How much of the net costs recorded to account 367 (underground conductors and devices), account 366 (underground conduit), account 365 (overhead conductors and devices), and account 364 (poles, towers, and transformers) and the associated reserve accounts are related to equipment that operates at a secondary voltage?

A. I don't know. Based on data request responses and conversations with the Company, the Company is unable to provide this information.

Q. Is there one single secondary service voltage and is the same infrastructure used to serve all secondary customers?

A. No. Service can be single or three phase, and can be received at 120 volts, 240 volts, and at higher voltages and be considered "secondary." It is my understanding that some of the equipment to serve some of the customers is similar or comparable, and some is very different.

Q. Why is it necessary to have more information on the portions of those accounts 364-367 and related reserves that are associated with service at given secondary voltages, for CCOS purposes?

A. The total values associated with equipment that operates at secondary voltages is necessary to isolate primary customers from the cost of the portion of the distribution system that they do not use.

Q. What is an additional reasonable use of this data?

A. A representative identification of the infrastructure and cost of the distribution system components that operate at various secondary service voltage is a meaningful step in improvement of the minimum distribution system classification method that is employed by Evergy in CCOS studies. In particular, the theory of the minimum distribution system method is to identify the theoretical cost of the entire distribution system if it were built of the smallest routinely-installed piece of each type of infrastructure. It is my understanding that for each account, the smallest routinely-installed piece of infrastructure for each indicated account operates at primary voltage. This is inconsistent with the theory underlying the minimum distribution system method. The minimum system would operate at single phase, 120 volt, with a maximum demand under 20 kW. Additional information is needed from Evergy to establish the components of each account that would be used to provide such service. Further, it may be reasonable to conduct a similar calculation for service at each secondary (and primary) voltage level for potential reflection of that level of cost in a demand or facilities charge. Further information is needed to determine if this demand or facilities charge concept is reasonable.

<u>Primary distribution costs and expenses by voltage</u>

Q. Why did you request information related to primary distribution costs and expenses by voltage?

A. Staff requests data concerning "primary distribution costs and expenses by voltage," are needed for similar reasons as described for secondary distribution costs and expenses by voltage. Namely, there are multiple primary service voltages and configurations, and it is important to have the ability within a CCOS to do the following analysis of each distribution account:

1. Identify the infrastructure and/or cost of customer-specific infrastructure for allocation to those customers as a group in the CCOS stage, and/or inclusion in the facilities or customer charge of those customers in the rate design stage,
2. Identify the portion of the infrastructure that is dedicated to customers served at secondary voltages to insulate customers served at primary voltages from those costs,
3. Identify the components that operate at various primary voltages to isolate customers served at higher primary voltages from those costs,
4. Identify representative components from Step 3 to serve as a surrogate for information that may not be available from Step 1,
5. Calculate reasonable customer-related classifications of each account.

Billing/Metering data

Q. What "Billing/Metering data" did you request?

A. I requested the information necessary to calculate class hourly loads at a consistent voltage, and the information necessary to estimate billing determinants for time-based rates.

My specific request is restated below:

> 2. For each rate code, provide the total number of customers served on that rate schedule on the first day of the month and the last day of the month;
>   a. For each rate schedule on which customers may take service at various voltages, the number of customers served at each voltage on the first day of the month and the last day of the month (this is only applicable if rate codes are not used to delineate the voltage at which customers are served);
> 3. For each rate code, the number of customers served on that rate schedule on the first day of the month and the last day of the month for which interval meter readings are obtained;
>   a. For each rate code on which customers may take service at various voltages, the number of customers served at each voltage on the first day of the month and the last day of the month which interval meter readings are obtained (this is only applicable if rate codes are not used to delineate the voltage at which customers are served);
> 4. For each rate code for which service is available at a single voltage, the sum of customers' interval meter readings, by interval;
>   a. For each rate code on which customers may take service at various voltages, the sum of customers' interval meter readings, by interval and by voltage (this is only applicable if rate codes are not used to delineate the voltage at which customers are served);
> 5. If any internal adjustments to customer interval data are necessary for the Company's billing system to bill the interval data referenced in parts 4. and 4.a., such adjustments should be applied to each interval recording prior to the customers' data being summed for each interval;
> 6. From time to time the Commission may designate certain customer subsets for more granular study. If such designations have been made, the information required under parts 1 – 5 should be provided or retained for those instances.
> 7. Individual customer interval data shall be retained for a minimum of fourteen months. If individual data is acquired by the Company in intervals of less than one hour in duration, such data shall be retained in intervals of no less than one hour.

Q. MIEC witness Mr. Brubaker joins in objecting to Staff's requested data, stating in his EMM testimony at page 6:

> "Q. STAFF SPENDS A CONSIDERABLE AMOUNT OF TIME AT PAGES 31-34 CITING A NUMBER OF DATA REQUESTS THAT IT POSED TO EVERGY, ALONG WITH THE RESPONSES. DO YOU HAVE ANY COMMENTS ON STAFF'S ISSUES WITH RESPECT TO DISTRIBUTION SYSTEM ALLOCATION?
> A. Yes. Staff seems to think that the inability to identify certain costs at the microscopic level makes Evergy's studies imprecise and unreliable.
> Q. WHAT IS YOUR REACTION TO STAFF'S CRITICISMS?
> A. The questions on pages 31-34 of Staff's direct testimony request a level of detail that is unnecessary to perform a class cost of service study. Rates are made for broad classes of customers, and information such as that requested in Question 0215 is in such minute detail that even if it were provided, it is difficult to see how it would be of any value in calculating class cost of service. Specifically, this question asks Evergy to identify, for each voltage and phase combination at which customers are billed, the number of customers billed on each combination, by rate schedule, and further to identify the number of customers for each combination at the beginning and 15th of each calendar month from January 2018 through December 2022 (120 data points). Furthermore, the question asks for hourly load data for each customer for the entire five-year period (43,800 data points for each customer).

Q. Did you ask for hourly load data for each customer?

A. No. I asked for hourly load data for customers on rate schedules and voltage levels under which fewer than 100 customers have served. Staff has generally requested and received individual customer hourly load data for various time periods for small classes with large customers. From time to time Staff has requested and received individual customer hourly load data from a sample of customers in classes with many small customers.

Q. Did you ask for the number of customers billed on by rate schedule and voltage at the beginning and 15th of each calendar month from January 2018 through December 2022?

A. Yes.

Q. Why did you ask for these pieces of information?

A. This question is asking Evergy to tell Staff how much energy it sold at meter to various groups of customers, and how many customers are in each group. Customers can change groups over time, and customers can come and go from time to time. Both first of the month and midmonth are common measures of customer counts, so I did ask for both numbers.

To add together metered usage when customers in a class are served at different voltages, you have to know what usage occurred at which voltage to add them together. This is similar to finding the total length of a piece of string that is 5 inches long, and a second piece of string that is 5 centimeters long. Adding the customer usage together without bringing them to a consistent voltage would not produce an accurate result.

In the case of classes comprised of a few big customers, I asked for more or less all the usage data, to simply add it up to class loads. In the case of classes with many small customers, I asked for 100 data points at each voltage level, so that I could use those sample customers and the total number of customers to estimate hourly loads.

Q. What had you planned to do with this information?

A. A few things:

1. Use actual customer data, over a few years, to estimate the bill volatility of various time of use rate scenarios,

2. Use actual customer data, over a few years, to estimate revenue volatility of various time of use scenarios,

3. Price out market energy to the classes. This is ideally done over more than one year to normalize out events like Winter Storm Uri,

4. Identify target hours for a coincident demand charge,

5. Study the utilization of various voltages of operation on the distribution system,

6. Evaluate the relationship between the varying service voltage rates within rate schedules.

CLASS COST OF SERVICE AND REVENUE ALLOCATION

Transmission Allocation and Corrected EMM Study

Q. Were you aware of the drag and drop error in your EMM transmission allocator, noted in the testimony of Kaviti Maini, at page 7 of her rebuttal testimony?

A. I was not. This error resulted from my inadvertent inclusion of cell D6 in my intended selection of cells D3:D5 of sheet “Paste” in my workpaper “ccos workbook for EMM surrebuttal.” As I updated the intended reference cells in rows 3-5, the inadvertent selection of the hardcode value in row 6 caused Excel to autofill values adding a value of 1 to the prior cell.

Q. Have you corrected your direct-submitted CCOS Study to address this error?

A. Yes. The summary table of results is provided below:

	Residential	SGS	MGS	LGS	LPS	Lighting	Other	Total
	$ 310,775,972	$ 51,001,275	$ 92,254,238	$ 140,556,495	$ 100,141,874	$ 9,660,982	$ 1,031,631	$ 705,422,467
Offsetting Revenue	$ 28,603,066	$ 5,021,210	$ 10,462,711	$ 15,641,072	$ 9,618,583	$ 156,310	$ 10,887	$ 69,513,839
Current Rate Revenue	$ 328,695,098	$ 70,950,862	$ 123,489,122	$ 182,782,977	$ 120,906,602	$ 9,887,749	$ 103,282	$ 836,815,692
Revenue Available for RoR	$ (10,683,940)	$ 14,928,377	$ 20,772,173	$ 26,585,409	$ 11,146,145	$ 70,457	$ (939,236)	$ 61,879,386
	$ 1,457,598,176	$ 217,856,410	$ 383,686,848	$ 543,993,133	$ 343,358,073	$ 45,982,702	$ 4,399,181	$ 2,996,874,523
Current RoR with New Income Tax Requirement	-0.73%	6.85%	5.41%	4.89%	3.25%	0.15%	-21.35%	
Return on Rate Base at System Average Return	$ 98,679,397	$ 14,748,879	$ 25,975,600	$ 36,828,335	$ 23,245,342	$ 3,113,029	$ 297,825	$ 202,888,405
Difference from System-Average RoR $	$ (109,363,336)	$ 179,498	$ (5,203,426)	$ (10,242,926)	$ (12,099,197)	$ (3,042,572)	$ (1,237,061)	$ (141,009,019)
Difference from System-Average RoR %	-33%	0%	-4%	-6%	-10%	-31%	-1198%	-17%
Estimated Net Class Cost of Service	$ 380,852,303	$ 60,728,944	$ 107,767,127	$ 161,743,758	$ 113,768,633	$ 12,617,701	$ 1,318,568	$ 838,797,033
Additional Rev Req for True-Up Estimate	$ 11,870,867	$ 1,892,874	$ 3,359,017	$ 5,041,426	$ 3,546,079	$ 393,284	$ 41,099	$ 26,144,645
Total Estimated CCoS at System-Average RoR	$ 392,723,170	$ 62,621,818	$ 111,126,144	$ 166,785,184	$ 117,314,712	$ 13,010,985	$ 1,359,667	$ 864,941,678
Total CCoS minus Current Rate Revenue	$ 64,028,072	$ (8,329,045)	$ (12,362,979)	$ (15,997,793)	$ (3,591,890)	$ 3,123,236	$ 1,256,385	$ 28,125,986
Current RoR with New Income Tax Requirement and True-Up Estimate	-1.55%	5.98%	4.54%	3.96%	2.21%	-0.70%	-22.28%	1.19%

Q. Does correction of this error cause you to revise your direct-recommended class-revenue allocation for EMM?

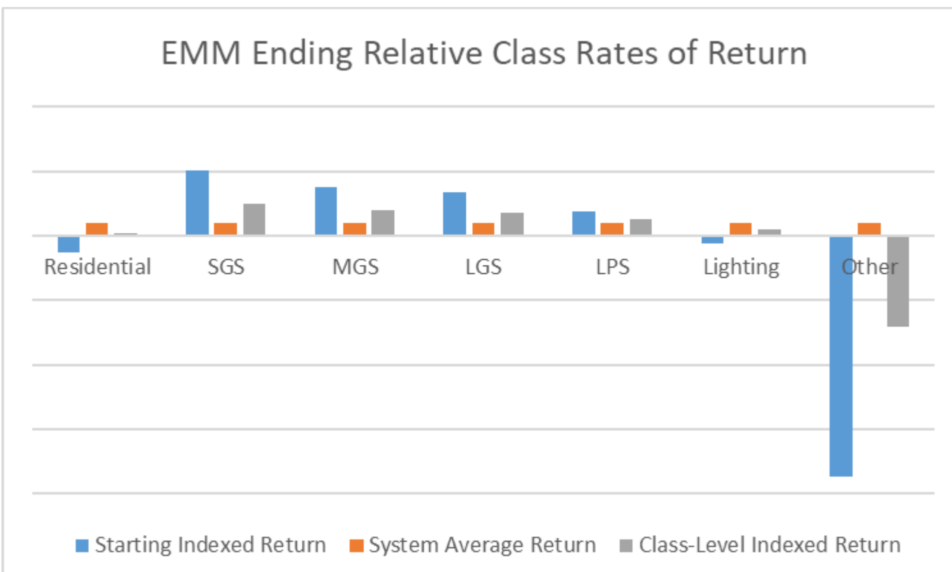
A. Yes. For purposes of aligning class revenue requirements with cost causation, I recommend that if an increase is ordered in this case in excess of approximately $22 million, the first $22 million be applied as a 1% increase to SGS, MGS, LGS, and LPS, and as a 5% increase to the residential class, the lighting class, and to the miscellaneous rate schedules associated with the “Other” class:

	Residential	SGS	MGS	LGS	LPS	Lighting	Other	Total
Potential Increase Level 1	5.0%	1.0%	1.0%	1.0%	1.0%	5.0%	5.0%	2.6%
Increase to Current Revenue	$ 16,434,755	$ 709,509	$ 1,234,891	$ 1,827,830	$ 1,209,066	$ 494,387	$ 5,164	$ 21,915,602
Difference from System-Average RoR $	$ 47,593,317	$ (9,038,553)	$ (13,597,870)	$ (17,825,623)	$ (4,800,957)	$ 2,628,848	$ 1,251,221	$ 6,210,384
Revenue Available for RoR	$ 5,750,815	$ 15,637,886	$ 22,007,065	$ 28,413,239	$ 12,355,211	$ 564,844	$ (934,072)	$ 83,794,988
Increase Level 1 RoR	0.39%	7.18%	5.74%	5.22%	3.60%	1.23%	-21.23%	2.80%

Any additional increases should be applied as an equal percentage increase to the current rate revenues of each class:

	Residential	SGS	MGS	LGS	LPS	Lighting	Other	Total
Potential Increase Level 2	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%
Increase to Current Revenue	$ 2,439,394	$ 526,558	$ 916,468	$ 1,356,514	$ 897,302	$ 73,381	$ 767	$ 6,210,384
Difference from System-Average RoR $	$ 45,153,923	$ (9,565,111)	$ (14,514,338)	$ (19,182,137)	$ (5,698,259)	$ 2,555,467	$ 1,250,455	$ -
Revenue Available for RoR	$ 8,190,209	$ 16,164,444	$ 22,923,533	$ 29,769,754	$ 13,252,513	$ 638,226	$ (933,306)	$ 90,005,372
Increase Level 2 RoR	0.56%	7.42%	5.97%	5.47%	3.86%	1.39%	-21.22%	3.00%

EMM	Residential	SGS	MGS	LGS	LPS	Lighting	Other
Starting Indexed Return	-130%	502%	381%	332%	186%	-59%	-1869%
Total Recommended Increase	$ 18,874,148	$ 1,236,067	$ 2,151,359	$ 3,184,344	$ 2,106,368	$ 567,769	$ 5,931
Ending Indexed Return	19%	247%	199%	182%	129%	46%	-706%



If an increase of less than $17 million is ordered in this case, I recommend it be allocated to the Residential, Lighting, and “Other” classes. If an increase of more than $17 million and less than $22 million is awarded, the first $17 million should be allocated to the Residential, Lighting, and “Other” classes, and the remainder should be applied as in Step 2, above.

Q. Evergy's witness Mr. Brown, in the EMM version of his rebuttal testimony at page 9 states that he "continue[s] to support the use of the A&E 4CP method as the best choice for the Company to allocate production and transmission capacity costs." Earlier, at pages 5-6 he testified "The A&E 4CP method is superior to A&E 4NCP because it is more reflective of how the Company plans its investment in production and transmission plant. That is, the Company bases these decisions on the CP requirements of the system, not the NCP requirements. Further, it is the four summer months from June through September that are the primary factors, and therefore the primary cost causative factors for the Company's production and transmission investments are Average and Excess Demand with a 4CP excess component." Similar testimony appears on page 3 of his rebuttal testimony. How are SPP transmission costs incurred by EMM and EMW?

A. SPP Schedule 11, Base Plan Zonal Charge and Region-wide Charge are assessed on monthly contributions to SPP zonal peak. Schedule 11 states that "Network Customer's monthly Resident Load will be its hourly load coincident with the monthly peak of the Zone that is the basis for charges under Schedule 11." The reality of Evergy's participation in the SPP as a driver of transmission revenue requirements deviates from the antiquated view of system investment drivers referenced by Mr. Brown. With SPP participation, 12 CP allocation is more reflective of cost causation for the majority of transmission-related revenue requirement.

Residential Customer Charge

Q. What impact does your revision to the residential revenue requirement you provide for EMM have on you Residential customer charge recommendation?

A. Due to the increase in the residential revenue requirement I recommend for EMM, I have revised my customer charge recommendation to increase the residential customer charge by the percentage adjustment to the Metro Residential class revenue requirement, rounded to the nearest quarter. Reflecting the adjustments described above, that value is now $12.00.

Q. Has it come to your attention that you included an error in your direct customer charge recommendation?

A. Yes. In my discussion at page 45 of my Direct Class Cost of Service testimony, I refer at lines 14 and 15 to "EMW." This reference should have been to "EMM."

Q. At pages 11-14 of her EMM testimony, Company witness Ms. Miller devotes significant discussion to Staff's customer charge review process, but seems to be confused what the actual Staff recommendation located in the paragraph contained in Staff's direct. Do you have any general responses to the concerns she raises?

A. Yes. For clarity, I have reproduced the testimony below, correcting the reference to EMM mentioned above:

> Q. What customer charge do you recommend for EMM and EMW?
>
> A. The EMM CCOS is not sufficiently reliable for development of specific rate elements. However, the directly-allocated costs and closely related expenses for EMM indicate a customer charge cost-causation of approximately $10. Because this amount is not inclusive of any related indirectly-allocated costs or expenses, I targeted retention of the existing customer charges. However, because I recommend consolidating customer charges across rate codes, I reviewed various levels of customer charges for EMM and EMW that would minimize the change in revenue recovered from customer charges. Ultimately, I recommend $11.55 as a reasonable residential customer charge for both EMM and EMW for all residential customers.

Q. Could you paraphrase this discussion?

A. Yes. A CCOS Study is a guide, and you shouldn't try to set customer charges down to the penny based on CCOS results. But, I went ahead and did a quick review of the normal customer charge components, and it came out to about $10.00, which is pretty close to the current customer charge. This is to say that given that my $10.00 result doesn't include all of the costs and expenses we usually pick up in a customer charge, it is probably on the lower end of the reasonable range if cost causation is the only factor. But, because of the rate structure and rate design changes contemplated in this case, customer impact considerations indicate it would be reasonable to increase the customer charge, so that the proportion of residential revenue that is recovered through the customer charge stays about the same.

Q. Even if a $16 customer charge were cost-justified in this case, would it be reasonable to implement?

A. No. Given the intra-class residential rate redesigns recommended by Staff and Evergy, and the expectation that the residential classes will receive an above-system-average rate increases, it is reasonable to limit the residential customer charge to the percentage of residential class revenue increase. Staff does not oppose maintaining consistency between the EMW and EMM residential customer charges, even if the applicable residential rate increases differ. Rounding resulting charges to the nearest quarter will likely ensure this consistency, but Staff is not opposed if further adjustment is required to achieve consistency between EMM and EMW.

Q. Has Evergy clarified the benefit it perceives to increasing the revenue recovery allocated to the residential customer charge?

A. Yes. As Ms. Bulkley testified in her direct testimony, at page 63 of the EMM version,

> The majority of an electric utility's cost are fixed costs that are incurred to construct and maintain the distribution system. As such, most of a utility's costs do not vary with energy consumption. However, rates are often structured to recover a large portion of a utility's fixed costs on a variable basis. This is particularly true for the residential customer class. Since a customer's usage varies from year to year, the more fixed costs that are recovered on a variable basis, the higher the volatility of annual cost recovery for the company. Therefore, cost recovery for utilities that have higher fixed customer charges are less susceptible to fluctuations in usage and are more likely to recover their costs to serve customers.

Note, while Ms. Bulkley testified "most of a utility's costs do not vary with energy consumption," that does not mean that those costs vary directly with the number of customers served. In fact, the number of residential customers served tends to increase steadily over time. Shifting revenue recovery toward this growing determinant and away from declining determinants is a strategy to increase the likelihood of recovering more revenue than was determined in a concluded rate case.

Q. Is the NARUC manual Ms. Miller refers to at page 11 of her EMM testimony "largely considered the industry standard," as she alleges?

A. The RAP manual has superseded the NARUC manual, and emphases the "Basic Customer Method." Because Staff's customer charge position in this case is based on other factors as discussed above, I will not elaborate on additional errors and mischaracterizations in this portion of Ms. Miller's testimony. In general, there are costs that vary with energy consumed, and there are costs that vary with the number of customers taking service, and there are costs that have no direct relationship to either of those metrics.

Q. Have you prepared estimates of residential rates for both EMW and EMM addressing the revised EMM positions discussed above?

A. Yes. In conjunction with my recommended ToU overlay, the rates provided in the table below are estimates of the rates that will result from Staff's recommended class revenue responsibility allocation and rate design:

	EMM	EMW
Customer Charge	$ 12.00	$ 12.00
Summer 0-600	$ 0.1405	$ 0.1201
Summer 600-1000	$ 0.1405	$ 0.1201
Summer 1000+	$ 0.1505	$ 0.1301
Non-Summer 0-600	$ 0.1159	$ 0.1048
Non-Summer 600-1000	$ 0.0959	$ 0.0848
Non-Summer 1000+	$ 0.0759	$ 0.0648
Summer Peak Overlay	$ 0.0100	$ 0.0100
Non-Summer Peak Overlay	$ 0.0025	$ 0.0025
Super-Off Peak Overlay	$ (0.0100)	$ (0.0100)

Generation Allocation

Q. Mr. Brown on behalf of Evergy, posits questions like "How should the Commission address costs that were not explicitly considered in the 1992 NARUC Cost Allocation Manual," what is your response?

A. The Commission should not "address" such costs. The Commission may inform its revenue requirement allocation decisions with the results of class cost of service studies, or it may inform the rate design decisions it makes with the results of class cost of service studies, but there is no particular resolution of each account's allocator that the Commission is required to make. The Commission may consider class cost of service studies and weight them accordingly based on the underlying revenue requirement relied upon, the level of detail considered, or the credibility of the performer. The Commission may find a given application of a particular allocator more reasonable than another in a given case. The Commission may consider the results of various studies or temper them based on factors such as those I mention above. However, the Commission does not need to decide the details of a given study, and any decision made by the Commission in a given case is not binding on the Commission in a future case.

Q. At page 3 of the EMM version of his rebuttal testimony, Mr. Brown testifies that "While there appears to be general consensus, both in this case and other recent cases before the Commission that Average and Excess demand is the appropriate capacity allocator for regulated utilities in the state, I will focus on the 4CP versus 4NCP decision." Is he correct?

A. No. As I stated at page 27 of my CCOS direct testimony "In these cases I was able to determine early on that EMM and EMW were unable to provide the data necessary to do a robust study of the proper classification, assignment, and allocation of the distribution system. I was also able to determine early on that rate design will be a time-consumptive issue in these cases, as will various optional tariff programs requested by EMM and EMW, such as subscription pricing and prepaid utility service. I was also disappointed to learn that hourly electrical consumption by rate code was not accessible by EMM and EMW aggregated by hour at the rate code level. **Given these known limitations on the reasonableness of the results of any CCOS studies I could do in these cases, and given the level of controversy that has surrounded the allocation of production capacity costs, production operation and maintenances expenses, and fuel and purchased power costs, I made the decision to essentially treat these areas as though the SPP integrated marketplace does not exist, for purposes of conducting the CCOS studies in this case**." [Emphasis added.]

Q. Does the SPP integrated marketplace exist?

A. It does. EMM and EMW participate in the SPP integrated marketplace. While the antiquated A&E production allocation methods can be used for a "quick and dirty" CCOS study, they are not reasonable, and more expert discretion is necessary in applying these study results to current scenarios than with other, more time consumptive and data-driven methods.

Q. Could you contrast criticisms in this case against Evergy statements in their IRP?

A. Yes. At page 14 of its 2021 IRP "Overview," filed April 20, 2021 in ER-2020-0036, under the heading "Conclusion," EMM stated,

> Our Plan ensures safe, reliable, affordable, and increasingly sustainable power for our customers. **By managing fossil generation through its shift from baseload to flexible resource**, and responsibly transitioning end-of-life facilities, we safeguard the system's overall reliability. At the same time, the Plan embraces state policy encouraging **continued transition to cleaner sources and delivers customer value through adding cost-competitive renewable resources, while reducing risk in our existing generation assets**.
>
> The Plan represents a roadmap for **sustainably transforming our generation fleet** for the benefit of all stakeholders. **For over a decade we have been working to reduce carbon emissions and transition to renewable energy.** Today, emissions are 51% below 2005 levels, reduction levels that rank near the highest of our peer companies; and one-third of the power used by retail customers is generated from renewable resources. Factoring in our emission-free nuclear energy, our customers receive more than half their energy from carbon-free resources.
>
> The Plan presents a responsible, sustainable approach to **accelerating this necessary transformation of our generation portfolio**. It delivers cleaner energy through balanced progress, targeting 70% through 2030. As Figure 2 highlights, it moves us steadily toward our goal of net-zero carbon emissions by 2045. [Emphasis added.]

This language emphasizes that coincident peaks are not the sole determinative factor in Evergy's fleet decisions, and clarifies that Evergy is changing and has been changing how it constitutes and operates its generation fleet. In contrast, Mr. Brown doesn't simply use the A&E as a simple plug-in to achieve a quick CCOS with known limitations, he offers it as an affirmatively good choice.

Q. Is Mr. Brown's statement on page 5 of his EMM rebuttal testimony that "The A&E 4CP method is superior to A&E 4NCP because it is more reflective of how the Company plans its investment in production and transmission plant. That is, the Company bases these decisions on the CP requirements of the system, not the NCP requirements," accurate?

A. No. In Evergy's Metro's response to DR 2 in Case No. EO-2021-0036, it stated "Evergy Metro and Evergy West are viewed as one by the Southwest Power Pool ("SPP") due to the joint Network Integrated Transmission Service ("NITS"). Therefore, when the combined utility is long on capacity, the market-based equivalent cost is used, and when the combined utility is short on capacity the cost of a CT is assumed." In other words, to the extent that capacity needs are considered, the Company plans its investment in production plant based on the combined EMW, EMM, and Evergy Metro Kansas system peak. Selection of an A&E allocator for a CCOS study is a departure from the reality in which either utility operates, but the authors of the NARUC manual make clear that an A&E CP study is simply a CP study, by stating "If your objective is – as it should be using this method – to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands."[5]

[5] Page 50, the 1992 NARUC Cost Allocation Manual.

More importantly at page 14 of its 2021 IRP "Overview," filed April 20, 2021 in ER-2020-0036, under the heading "Key Considerations for Developing the Plan," EMM stated,

> ….We considered a variety of factors, including how to:
> • Maintain both the reliability and flexibility of our system. **We assessed the amount of firm, dispatchable capacity in our system relative to expected demand**, while meeting the reserve margin requirements developed by the Southwest Power Pool, our market operator.
>
> • Ensure affordability for our customers, particularly given the growing reality of increased insurance, financing, and other **costs that would be passed along to customers if Evergy doesn't complete timely transition of its generation portfolio**. **We measured affordability by analyzing the net present value of revenue requirements across a range of potential scenarios**.
>
> • Pair energy efficiency investments that lower costs for all customers along with supply side investments. Engaging customers in shaping the load curve, enabled by grid modernization investments, will improve integration of distributed resources such as solar and storage; integrate demand flexibility to address extreme weather events; and encourage energy usage (e.g., from electric vehicle charging) during off-peak periods to reduce stress on the grid and improve grid utilization.
>
> • Ensure environmental stewardship while managing financial risk and providing flexibility. **Given the changing energy landscape, we paid particular attention to cost risk and environmental impact. Risk assessment focused on the potential for high-cost outcomes based on uncertain factors. We evaluated environmental impact based on each plan's carbon emissions trajectory.**
>
> • Maintain a safe operating environment for all employees.
> [Emphasis added.]

Q. What is significant about the text you've emphasized above?

A. Evergy is stating that it does its system planning recognizing the role of the SPP, seeking to lower the net present value of revenue requirement, and looking at risk factors including environmental risks, and particularly the risk of environmental compliance costs.

Q. Why is it necessary to allocate the capacity costs for generation facilities that operate with low or no fuel costs to the classes on the basis of energy in a case where energy sales revenues are allocated on the basis of energy?

A. Despite MIEC witness Mr. Brubaker's professed confusion at pages 4 and 5 of his rebuttal testimony, it is obvious that there is a fundamental mismatch in allocating the cost of non-dispatchable energy on the basis of capacity, but allocating the revenues of non-dispatchable energy on the basis of energy. It is important to consider how both stable and variable generation costs, including fuel, are allocated when allocating the cost of market energy, and the proceeds of energy market participation. Both EMM and EMW participate in the SPP integrated market and it is fundamentally unfair to charge one group of customers for the costs of building and maintaining a power plant, while providing the sales revenue from that power plant to another group of customers. This is acutely true where generation with little to no marginal costs such as fuel are concerned. It is not a quick and simple process to realign net energy revenues to align the revenue requirement benefits of capacity with the cost responsibility for that capacity, as would be imperative under the approach urged by Mr. Brubaker.

Q. On what basis do EMM and EMW incur the obligation to obtain Renewable Energy Credits?

A. RECs are required based on the energy consumed by each customer, so it would be appropriate to allocate REC costs on the basis of energy, in the context of a CCOS study at this time, whether or not construction of a given facility is attributable to Renewable Energy Standard compliance.

Q. At page 7 of his EMM testimony, MIEC witness Mr. Brubaker opines, “Generation investment, regardless of the type generation, is still generation investment and should be treated as such. And, nobody would build plants simply to earn profits in SPP.” If EMM and EMW base their IRP on NPVRR, what are they prioritizing?

A. Earning profits in the SPP.

RESPONSE TO RATE SCHEDULES AND RATE DESIGN

Residential Rate Schedules and Rate Design

Q. In her rebuttal testimony at pages 8-9 Evergy witness Ms. Miller discusses how the Company intends to “forge ahead” with their own efforts to “eliminate end use rates/distinctions.” In the absence of ordering the consolidations and designs recommended in your direct testimony, what reasonable steps, at a minimum, should the Commission take in this case to remove end use rates and pricing distinctions?

A. While Staff recommends the consolidations and design indicated in my direct CCOS testimony, in the absence of approval of my direct recommendations it would be reasonable to lessen the winter decline in place for Residential Space Heating customers. Evergy has not demonstrated that this decline is cost-based. Note, similarly, for non-residential customers, if my direct rate structure recommendations are not adopted, removal of the seasonal energy rate element and end-use rate differentials should proceed, as neither have been shown by Evergy to be cost-based.

Further, it would be reasonable to align the summer rates for all residential customers.

Q. At page 8 of the EMM version of her testimony, Evergy witness Ms. Winslow includes the following exchange:

> Q: Does Staff witness Lange describe why such an ultra-low differential makes sense for customers?
> A: Witness Lange only provides that the proposed rate will "mitigate the TOU rates to customers with energy-intensive HVAC units". She also purports that it will simplify the customer experience and rely on the TOU education process Evergy began, as outlined in the 2018 Rate Design S&A.

Given Ms. Winslow's apparent confusion on this issue, are there additional areas of your direct testimony it would benefit her to direct her attention to?

A. Yes. Ms. Winslow appears to have overlooked the discussion of cost causation provided from pages 16 to 23 of my direct testimony, under the heading "Time of Consumption as a Factor in Cost-Based Rate Design". To summarize, the low differential I recommend is cost based, recognizes Evergy's 8 month "winter" seasonal rates, and aligns revenue responsibility with cost causation to a greater degree than current rates, while maintaining revenue stability.

Q. Ms. Winslow expresses concern that customers may not change behaviors much as a consequence to a low-differential time-based rate.[6] What is your response?

A. That could be, but is irrelevant to taking this opportunity to better align revenue recovery with cost-causation.[7] Customers are not likely to change behaviors much as a

[6] See Winslow rebuttal at page 3, "Q: How do you describe the fundamental purpose of a TOU rate? A: I see the purpose of TOU rates (or time-variant rates, in general) as two-fold. First, a TOU rate provides a more representative price signal of actual costs to the customer and second (in relation to the first), a properly designed TOU rate is meant to create more elasticity of demand for various end uses to improve efficiency of resources."
Winslow rebuttal at page 44, "Q: Can you clarify why you believe Staff's "ultra-low" differential defeats the fundamental purposes of a TOU rate? A: A $0.01/kWh change would not send any meaningful price signal to a customer such that they would be motivated to affect their usage through behavioral change." and
Winslow rebuttal at page 9, "The purpose of the TOU rate is to provide a price signal to create behavior change to move certain activities off-peak."

[7] In the Staff Report on Distributed Energy Resources, filed April 5, 2018, in File No. EW 2017-0245, concerning residential and utility-wide rate design, Staff recommended the following:
Initial steps to be taken during or prior to applicable rate cases:
a. Residential Rate Design:
i. Improve customer education regarding cost composition and energy cost differences over time of day and season.
ii. Review rates on an unbundled basis, with potential to provide tariffed rates on an unbundled basis.

iii. Implement a Low-differential TOU rate design related only to energy price difference or existing rate design blocks, with relatively long on-peak periods.
iv. Study determinants for an on-peak demand charge.

* * *

c. Utility-wide
i. Study bifurcating Fuel and Purchased Power costs into the TOU time periods for recovery of differences through bifurcated FACs.
ii. Study distribution of DER on existing system.
iii. Identify locations on the distribution and transmission systems where DER may be an alternative to expansion or replacement of the system.
iv. Develop strategies to encourage strategic placement and deployment of DER to reduce overall system investment needs and operation expenses, including transmission congestion including study of locational rate designs and location-dependent compensation schemes.
v. Study located DER scenarios as part of Chapter 22 planning consistent with Staff's recommendations contained in Section VII. Changes to IRP process or Chapter 22.
vi. Study energy cost distribution and system utilization to find opportunities for efficient utilization and pricing – for example, some utilities experience significant winter night and evening usage – to refine time periods applicable to time of use rates and develop super on-peak or super off-peak rates.

Phase 2 (approximately 2025 time frame, will vary by utility and rate case timing):
a. Residential:
i. Continued and increased customer education regarding cost composition and energy cost differences over time of day and season.
ii. Increase TOU differential to recover some generation capacity costs on-peak.
iii. Incorporate super on-peak and super off-peak TOU elements, which may vary by season.
iv. Implement a 12 month demand charge for recovery associated with local distribution facilities.

* * *

c. Utility-wide
i. Study distribution locational pricing determinants for locational rate designs; study location-dependent compensation schemes.
ii. Revenue Decoupling.
iii. Based on outcomes of studies of beneficial DER location, locate DER or incent the location of DER using reasonably designed compensation designs.

Anticipated goals (approximately 2030 time frame, will vary by utility and rate case timing):
a. Residential:
i. Continued and increased customer education regarding cost composition and energy cost differences over time of day and season.
ii. Implement on-peak demand charge to nearly fully recover generation capacity costs on peak, not already included in on-peak and super on-peak elements.
iii. Consider and implement, if appropriate, distribution locational rates or rate elements.

* * *

c. Utility-wide
i. Study distribution locational pricing determinants.
ii. Based on outcomes of studies of beneficial DER location, locate DER or incent the location of DER using reasonably designed compensation designs.

consequence of the current time-agnostic rate design. The goals of the low-differential time-based rate are chiefly to improve alignment of revenue responsibility and cost causation and to reinforce awareness of the timing of consumption as a factor in energy costs among all energy consumers. Ms. Winslow's desires to influence larger changes in the energy consumption of a smaller number of customers should not stand as a barrier to these reasonable goals. Staff encourages the Commission to take this opportunity to improve the alignment of revenue responsibility and cost causation and to reinforce awareness of the timing of consumption as a factor in energy costs among all energy consumers.

Q. Would incorporating avoided or avoidable distribution system costs into the studied time-based differential increase the level of differential that can be supported as cost-based?

A. Yes. However, I discussed in direct, distribution costs aren't variable in the same manner as energy costs, and, EMM takes the position in Volume 4.5: Transmission and Distribution Analysis ", of its IRP materials filed in EO-2021-0035, at pages 25 and 26 that,

> As in the 2012 IRP submittal, Evergy INC. made assumptions regarding planned system expansion projects in areas that are designated as "growth areas" versus areas designated as "established areas". Again, targeting was focused on capital projects associated within established areas since targeted DSM (Demand Side Management) programs were unlikely to be able to delay the need to expand substations on the fringe of metro-area growth because these areas contained significant "green space" with large areas that remain undeveloped.
>
> Distribution Planning's annual review of 15-year load projections revealed the fact that loads for these "established areas" continue to flatten and more commonly, decline, which has eliminated the need for expansion projects in these areas. It seems reasonable that as load growth has fallen off in the established areas, that efficiencies gained by replacing older heating/cooling units, lighting, and other older appliances, would begin to significantly impact peak loads for these areas. In the 2012 IRP submittal, the Gladstone, Claycomo, and Chouteau substations were identified as substations located in established areas where a system expansion project might be needed at

> some point in the future, making these a viable candidate for targeted DSM programs. However, a review of the most recent 15-year projections identifies the Gladstone and Chouteau substations to be in modest to significant load decline through year 2035, with total substation loads dropping from as little as 2% at Gladstone to as much as 17% at Choteau substation. Currently, Evergy INC. has not identified any specific capital projects located within any established areas that can be specifically targeted for DSM programs. Areas that have been identified as established areas either have sufficient capacity available to absorb the limited growth or are in load decline. These areas will continue to be monitored by Distribution Planning to determine if future opportunities for targeted DSM might become available. Should economic conditions improve, and/or significant redevelopment occurs in these established areas, opportunities to target DSM programs to delay or eliminate the cost to expand capacities for these areas may again exist.

In other words, in the IRP, EMM takes the position that avoided distribution costs cannot be valued at this time, because the system has sufficient capacity.

Optional Time-Based Residential Rate Schedules

Q. Do you understand Ms. Winslow's testimony at page 2 of her EMM rebuttal that "Staff witness Sarah Lange recommends that Evergy's 3-period opt-in TOU rate be modified to a low-differential default TOU rate?"

A. No. Staff has recommended Evergy's general service rate schedule be modified to include low differential ToU elements in their rate structures, to survive as the default rate schedule. In my direct, I noted that the Evergy-proposed Residential Time of Use – Two Period RTOU-2 Rate Schedule is less objectionable than the other optional rate proposals Evergy has included in this case, though it is still not cost-based. I noted that if the Commission desires continuation of a time-based rate that exceeds cost-based justification, the Evergy-proposed RTOU-2 design is the most reasonable of the Evergy designs to promulgate. Further, I noted that, if a well-designed separately-metered EV charging rate is not implemented, this RTOU-2 design is not unreasonable for use as a rate required of participants in the Residential EV rebate programs. I also noted that the existing three period opt-in RTOU rate design is less reasonable than the RTOU-2 design.

Non-Residential Rate Design

Q. Both MIEC witness Mr. Brubaker and MECG witness Ms. Maini state they do not understand how to estimate the rate impact for the large customer classes. Using Staff's direct-filed determinants and utility-level revenue requirement, and the corrected EMM class-revenue requirements you describe above, could you provide an example ending-rate for the LGS EMM class? [8]

A. Yes. Staff's recommendation is that each LPS and LGS rate code be modified to include the time-based overlay. Customers in LGS and LPS would not have the ability to opt out of the overlay. Therefore, actual rates will vary with final determinants and ordered class-level revenue requirements, an example is stepped through below, with resultant rates based on Staff's direct-filed revenue requirement and Staff's corrected EMM CCOS Study and recommended class-level revenue allocation.

The first step will be to eliminate the EMM end-use discount for all-electric customers, by applying the existing general service rates to the determinants existing for all-electric rates. This creates approximately $1.3 million in additional revenue.

[8] At page 13 in her ER-2022-0129 testimony, regarding Staff's recommendation of applying the ToU overlay to the LPS and LGS rate schedules, Ms. Maini testifies, "I interpret Staff's proposal to mean that customers on LGS and LPS rate schedules will need to opt out of a yet to be determined TOU rate if they do not prefer to be on this rate. It is not clear but I am assuming that customers can opt to continue receiving service on their current rate schedules in the event they opt-out."
At page 10 in his EMM testimony, Mr. Brubaker includes the following exchanges, "Q DID STAFF PRESENT ANY INFORMATION FOR NON-RESIDENTIAL CUSTOMERS THAT WOULD INDICATE THE NET RATE SCHEDULE IMPACT OF ADDING THESE OVERLAYS TO INDIVIDUAL RATE SCHEDULES? A No. Staff did not provide any information showing what that impact would be, nor did it study the potential impacts to individual customers taking service under the various non-residential rates. Q WHAT IS YOUR RECOMMENDATION? A Staff's proposals may be reasonable, but there is no basis in this case to evaluate them. A better approach would be to consider these enhancements in collaborative proceedings that would take place between this case and the next rate case."

LARGE GENERAL SERVICE						
					End Use Rate Elimination	
			Starting Determinants	Starting Revenues	Determinants	Revenues
A: CUSTOMER CHARGE						
0-24 KW	$	118.82		$ -		$ -
25-199 KW	$	118.82		$ -		$ -
200-999 KW	$	118.82	9,121	$ 1,083,757	9,121	$ 1,083,757
1001+ KW	$	1,014.44	1,429	$ 1,449,635	1,429	$ 1,449,635
Separately Metered Space Heat	$	2.72	180	$ 490	-	
B: FACILITIES CHARGE						
SECONDARY:	$	3.399	4,984,357	$ 16,941,830	4,984,357	$ 16,941,830
PRIMARY:	$	2.818	1,603,861	$ 4,519,681	1,603,861	$ 4,519,681
C: DEMAND CHARGE						
SECONDARY-SUMMER: (1, Heat, 3)	$	6.788	1,382,476	$ 9,384,244	1,382,476	$ 9,384,244
SECONDARY-WINTER (1, Heat)	$	3.652	2,013,155	$ 7,352,041	2,644,214	$ 9,656,669
PRIMARY-SUMMER (2, 4)	$	6.634	448,756	$ 2,977,049	448,756	$ 2,977,049
PRIMARY-WINTER (2)	$	3.569	634,790	$ 2,265,566	780,059	$ 2,784,031
SECONDARY-WINTER - ELEC ONLY (3)	$	3.382	631,059	$ 2,134,242	-	
PRIMARY-WINTER - ELEC ONLY (4)	$	3.302	145,269	$ 479,679	-	
D: ENERGY CHARGE						
SECONDARY-SUMMER: (1, heat, 3)						
0-180 hrs use per month	$	0.09569	230,752,714	$ 22,080,727	230,752,714	$ 22,080,727
181-360 hrs use per month	$	0.06597	185,866,144	$ 12,261,590	185,866,144	$ 12,261,590
361+ hrs use per month	$	0.04248	115,073,327	$ 4,888,315	115,073,327	$ 4,888,315
SECONDARY-WINTER: (1, heat)						
0-180 hrs use per month	$	0.08793	316,954,964	$ 27,869,850	430,113,102	$ 37,819,845
181-360 hrs use per month	$	0.05070	244,543,381	$ 12,398,349	342,885,611	$ 17,384,300
361+ hrs use per month	$	0.03570	145,966,359	$ 5,210,999	206,771,155	$ 7,381,730
PRIMARY-SUMMER: (2, 4)						
0-180 hrs use per month	$	0.09355	76,744,806	$ 7,179,477	76,744,806	$ 7,179,477
181-360 hrs use per month	$	0.06439	68,866,957	$ 4,434,343	68,866,957	$ 4,434,343
361+ hrs use per month	$	0.04148	38,140,110	$ 1,582,052	38,140,110	$ 1,582,052
PRIMARY-WINTER: (2)				$ -	-	$ -
0-180 hrs use per month	$	0.08592	108,026,657	$ 9,281,650	134,179,519	$ 11,528,704
181-360 hrs use per month	$	0.04949	96,470,241	$ 4,774,312	119,951,720	$ 5,936,411
361+ hrs use per month	$	0.03500	56,031,380	$ 1,961,098	72,055,020	$ 2,521,926
SECONDARY-WINTER - ALL ELECTRIC (3)						
0-180 hrs use per month	$	0.08455	110,109,955	$ 9,309,797	-	
181-360 hrs use per month	$	0.04537	95,294,047	$ 4,323,491	-	
361+ hrs use per month	$	0.03541	57,756,613	$ 2,045,162	-	
PRIMARY-WINTER - ALL ELECTRIC (4)						
0-180 hrs use per month	$	0.08277	26,152,862	$ 2,164,672	-	
181-360 hrs use per month	$	0.04437	23,481,479	$ 1,041,873	-	
361+ hrs use per month	$	0.03473	16,023,640	$ 556,501	-	
E: SEPARATELY METERED S/H - WINTER						
SECONDARY	$	0.05915	9,144,548	$ 540,900	-	
PRIMARY		0				
F: REACTIVE DEMAND ADJUSTMENT	$	0.853	339,512	$ 289,604	339,512	$ 289,604
G: Net ToU Overlay						
Total Revenue			2,021,400,184	$ 182,782,977	2,021,400,184	$ 184,085,921
					Impact of Enduse Elimination:	**$ 1,302,944**

Then, the kWh sales by season must be analyzed to estimate the revenue impact of the ToU overlay of a $0.01/kWh during summer peak hours, $0.0025/kWh during non-summer peak hours, and a year-round discount of -$0.01/kWh during super off-peak hours, as billed at secondary voltage (those values are +/-$0.00977 and $0.00244 for service at primary voltage).

		Energy		Overlay Rate		Revenues	
	kWh	On Peak	Off Peak	On Peak	Off Peak	On Peak	Off Peak
Secondary Summer	531,692,185	92,968,772.92	115,496,584	$ 0.010000	$ (0.010000)	$ 929,688	$ (1,154,966)
Secondary Non-Summer	979,769,867	164,441,052.42	222,072,399	$ 0.002500	$ (0.010000)	$ 411,103	$ (2,220,724)
Primary Summer	183,751,873	32,129,842	39,915,414	$ 0.009770	$ (0.009770)	$ 313,909	$ (389,974)
Primary Non-Summer	326,186,259	54,745,929	73,932,632	$ 0.002440	$ (0.009770)	$ 133,580	$ (722,322)
						$ 1,788,279	$ (4,487,985)
							$ (2,699,706)

The revenue impact estimated is a reduction to revenues of approximately $2.7 million. This impact can be summed with the impact of the end-use elimination:

Impact of Enduse Elimination:	$ 1,302,944
Net Impact of ToU Implementation:	$ (2,699,706)
	$ (1,396,762)

The next step is to increase rates, applied as the same percent adjustment to each revenue element, for the estimated class-level revenue increase, net, of the additional revenue produced by eliminating end-use discounts and the change in revenue introduced by the ToU overlay. In this example, the overall increase for LPS is recommended as approximately $3.18 million:

LGS Increase:	$ 3,184,344
Net Change from Above:	$ (1,396,762)
	$ 1,787,582
% Change from Original Class Revs:	0.98%

The final step for these purposes is to apply the change found above to the rate elements, to be applied as an equal percentage change, with appropriate rounding, and to check resulting revenues:

LARGE GENERAL SERVICE	Determinants	Estimated Ending Rates	Ending Revenues
A: CUSTOMER CHARGE			
0-24 KW		$ 119.98	$ -
25-199 KW		$ 119.98	$ -
200-999 KW	9,121	$ 119.98	$ 1,094,338
1001+ KW	1,429	$ 1,024.36	$ 1,463,810
Separately Metered Space Heat	-		
B: FACILITIES CHARGE			
SECONDARY:	4,984,357	$ 3.43	$ 17,096,345
PRIMARY:	1,603,861	$ 2.85	$ 4,571,005
C: DEMAND CHARGE			
SECONDARY-SUMMER: (1, Heat, 3)	1,382,476	$ 6.85	$ 9,469,958
SECONDARY-WINTER (1, Heat)	2,644,214	$ 3.69	$ 9,757,149
PRIMARY-SUMMER (2, 4)	448,756	$ 6.70	$ 3,006,667
PRIMARY-WINTER (2)	780,059	$ 3.60	$ 2,808,213
D: ENERGY CHARGE			
SECONDARY-SUMMER: (1, heat, 3)			
0-180 hrs use per month	230,752,714	$ 0.09663	$ 22,297,635
181-360 hrs use per month	185,866,144	$ 0.06662	$ 12,382,403
361+ hrs use per month	115,073,327	$ 0.04290	$ 4,936,646
SECONDARY-WINTER: (1, heat)			
0-180 hrs use per month	430,113,102	$ 0.08879	$ 38,189,742
181-360 hrs use per month	342,885,611	$ 0.05120	$ 17,555,743
361+ hrs use per month	206,771,155	$ 0.03605	$ 7,454,100
PRIMARY-SUMMER: (2, 4)			
0-180 hrs use per month	76,744,806	$ 0.09446	$ 7,249,314
181-360 hrs use per month	68,866,957	$ 0.06502	$ 4,477,730
361+ hrs use per month	38,140,110	$ 0.04189	$ 1,597,689
PRIMARY-WINTER: (2)	-		
0-180 hrs use per month	134,179,519	$ 0.08676	$ 11,641,415
181-360 hrs use per month	119,951,720	$ 0.04997	$ 5,993,987
361+ hrs use per month	72,055,020	$ 0.03534	$ 2,546,424
F: REACTIVE DEMAND ADJUSTMENT	339,512	$ 0.86134	$ 292,435
G: Net ToU Overlay			
Total Revenue	2,021,400,184		$ 185,882,750

Q. For actual compliance tariffs, would this be the last step?

A. No. A comparison to the starting and ending revenues indicates that due to rounding, this rate design would under-collect from target by over $84,000.

Starting Revenues:	$	182,782,977
Class Increase:	$	3,184,344
Target Revenue:	$	185,967,321
Ending Revenue:	$	185,882,750
Target to Ending:	$	84,571

For compliance tariffs, the rates designed above would be adjusted to get the class revenues as close to the target revenues as is practicable, without going over. This process can be lengthy, and is specific to the literal ordered revenue requirement, down to the penny.

Q. Did any party provide feedback on the order of operations described above, and does the order of operations cause changes in final rates?

A. No party provided feedback in rebuttal testimony, and yes, the order of operations will result in different rates. For example, it might be reasonable to include the revenue impact of the elimination of end-use energy charges within the energy charges, and the elimination of separately-metered charges within the customer charges. It might be reasonable to include the revenue impact of the elimination of end-use energy charges within the energy charges by season. The precise order of operations dictates how the spreadsheet must be set up, and it is not a reasonable use of time and resources to set up rate calculations for various rate schedules for various orders of operations.

Q. Did any party provide feedback in rebuttal testimony to the hours selected for on peak and super off-peak time period definition?

A. No. No party provided feedback on this area in rebuttal testimony. The hours selected and any exclusions implemented must be known before the ToU characteristics for each class can be determined, which must be done prior to calculation of the ToU determinants, which are necessary so that the ToU overlay revenue impact can be calculated. It is not reasonable to calculate the characteristics or determinants for each class and rate schedule under various scenarios.

Q. Could any party have made these calculations for the rate schedule in which their parties have an interest?

A. Yes. In fact, a given party could calculate the specific impact of the ToU overlay on their interested customers using their customers' hourly load data, which data Evergy did not provide to Staff.

Q. What is the "rate schedule impact" of the ToU overlay, as requested by MIEC witness Mr. Brubaker?

A. $0. As plainly described in Staff's direct recommendation, at the level of the each rate schedule, the ToU overlay revenue impact is to be netted from the change in revenue requirement ordered in this case.

Q. Is it your recommendation that non-residential customers may opt out of the ToU overlay as referenced by MECG witness Ms. Maini?

A. No. Staff's recommendation is that the SGS, MGS, LGS, and LPS rate schedules incorporate this time-variant element.

Q. Is it your belief that time for additional study of the ToU overlay would be beneficial?

A. No. Ironically, Mr. Brubaker recommends further study be made of these designs, but, as discussed above, he recommends Evergy not provide the data necessary to refine the ToU overlay or to estimate individual customer impacts. This is a very modest ToU element. Incorporation of this element into bills at this point in time accomplishes three things in advance of any additional modifications to the non-residential rate schedules:

1. **Gives customers a price signal.** This price signal may begin to inform them that their current hours-use price signals are improper. For example, the hours-use structure causes a higher average $/kWh bill for customers who use energy predominantly off-peak, in that it focuses solely on load factor. Similarly, under the hours-use structure, two customers

could have identical bills but very different usage patterns. The ToU overlay begins to send signals to alert customers to these facts.

2. **Creates billing determinants.** Currently, Staff relies on aggregated class-level hourly sales information used for weather normalization to create and analyze ToU rate designs. Including the ToU elements as rate components will result in the creation of billing determinants by rate code (in which Evergy reflects general service voltages), and by billing month. This information is critical to estimating revenue impacts of modern rate structures, and to assessing the reliability of the existing hourly data for revenue purposes.

3. **Improves alignment of cost causation and revenue responsibility.** Obviously, parties in this case have devoted considerable time to the area of cost allocation and revenue responsibility allocation and have requested the Commission devote significant time and resources to these areas as well in reviewing all evidence presented. However, as is illustrated below, other than local facilities, the costs of serving a customer do not vary with a customer's NCP demand, the costs vary with when energy is consumed, and classes are no longer the best tool for estimating a customer's load shape.

PISA RATE CAPS

Q At this time, is it apparent whether rate caps pursuant to Section 393.1655 RSMo (PISA recovery caps) will be triggered in this case?

A. As discussed in the surrebuttal testimony of Brad Fortson, the pending EMW FAR filing, ER-2023-0011, included requests by Evergy to defer approximately $31 million. The timing of resolution of that case appears to be determinative of whether or not the PISA recovery caps will be operational in this case, for EMW.

Q. If the PISA recovery cap is triggered, what is an appropriate resolution to be incorporated into the compliance tariff implementing this rate case?

A. To the extent the EMW LPS recovery cap is triggered, Staff recommends limiting the increase to the EMW LPS rate class to the extent necessary to remain compliant with the PISA recovery cap. The amount unable to be allocated to the LPS rate class should then be allocated to all other customer classes through the application of a uniform percentage adjustment to the revenue requirement responsibility of all the other customer classes, as required by 393.1655(6). Best practice would be to denominate those amounts so-allocated as a separate line item on customer bills.

CONCLUSION

Q. Does this conclude your surrebuttal 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-2022-0129
In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service	)	Case No. ER-2022-0130

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW SARAH L.K. LANGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Surrebuttal Testimony of Sarah L.K. Lange*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L.K. Lange
SARAH L.K. LANGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 15th day of August 2022.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin
Notary Public