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Witness: *Sarah L.K. Lange*
Sponsoring Party: *MoPSC Staff*
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MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF / RATE DESIGN DEPARTMENT

SURREBUTTAL / TRUE-UP DIRECT TESTIMONY

OF

SARAH L.K. LANGE

EVERGY METRO, INC., d/b/a Evergy Missouri Metro

CASE NO. ER-2026-0143

Jefferson City, Missouri
September 2026

*** Denotes Highly Confidential Information ***

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Q. Please state your name and business address.

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

Q. Are you the same Sarah L.K. Lange who contributed to Staff's Rate Design Report, filed revenue requirement direct testimony, rate design direct testimony, and rebuttal testimony?

A. Yes.

SUMMARY

Q. What is the purpose of this testimony?

A. In this testimony I will:

Provide Surrebuttal testimony:

- explain the level of socialized energy expense associated with LLPS load that is included in the Fuel Adjustment Clause ("FAC") Fuel Adjustment Rate ("FAR") established for service beginning October 2026, based on Large Load Power Service ("LLPS") energy usage in the period January 1, 2026 – June 30, 2026, consistent with Staff's recommended FAC treatment going forward under FAC Option 2, which segregates a proration of energy expense based on actual market values and actual consumption by LLPS and non-LLPS customers in each hour,

- respond to testimony related to the cost of serving large loads, rate design considerations for large loads, and FAC treatment of LLPS customers, and
- explain the relative uncertainty associated with incorporating dummy LLPS customer characteristics into jurisdictional allocation factors and other case elements, as opposed to incorporation of the difference between an estimate of the expected cost of energy (plus an estimate of additional expected transmission expenses) from the estimated expected revenue, with 100% allocation of that new net revenue to the Missouri jurisdiction,
- respond to testimony related to certain tariff, Class Cost of Service ("CCOS"), and Rate Design issues,

Provide True-up Direct Testimony:

- to recommend the level of imputed revenue from Customer A for purposes of setting EMM's[1] rates in this case,
- to recommend the level of imputed usage from Customer A for purposes of setting the FAC base if the Commission orders implementation of FAC Option 1, and the information required for calculation of FAC Option 2, and

Present corrections to my Schedule 4 to the Staff Rate Design Report, and to my rebuttal testimony concerning income eligible rate allocation.

<u>SURREBUTTAL CONCERNING LLPS AND LARGE LOAD ISSUES</u>

Q. EMM's rebuttal testimonies include varied references to net system input ("NSI") and jurisdictional allocations in response to Staff's testimony concerning large loads. What is the relationship of these issues?[2]

[1] Evergy Metro, Inc., d/b/a Evergy Missouri Metro ("EMM").
[2] See EMM witnesses, Patrick Aron Branson testimony at pages 10 – 11, Hsin Foo testimony at page 10, line 1 – page 12, line 5 and Linda J. Nunn testimony at page 12, lines 3 – 10.

A. EMM's position is to increase the Missouri share of the total cost of operating the Evergy Metro utility. In other words, if the cost of running the total Evergy Metro utility is $Z billion per year, and current rates reflect that cost as appropriately recovered as $X billion to Missouri, and $Y billion to Kansas, EMM's position in this case is that the Missouri cost responsibility should be increased because of the new large customers.[3]

Q. Does this approach increase the "fixed" costs that Missouri ratepayers are responsible for paying?

A. Yes.

Q. Do new revenues from new large loads offset the increases in "fixed" costs, or will other Missouri ratepayers pay higher rates because of the increase in Missouri cost responsibility?

A. That will depend on how a series of interrelated issues is determined by the Commission. This interrelation, along with the relative reasonableness of EMM's suggested approach and Staff's recommended approach are addressed in greater detail in the section *Allocated and Direct Revenues and Cost of Service*.

LLPS Energy Expense Socialized through Current FAC and Positive Regulatory Lag

Q. In her rebuttal testimony at page 10, lines 11 – 16, Ms. Nunn testifies, concerning Staff's direct-filed regulatory lag projections that,

> I do not believe the projections presented by Ms. Mastrogiannis and Ms. Lange should be viewed as reliable estimates of future

[3] Note, Kansas responsibility will not be reduced until and unless an appropriate proceeding in that jurisdiction recognizing an equal and offsetting reduction in allocated cost of service.

> regulatory lag because they depend on numerous assumptions regarding future LLPS customer growth, wholesale energy costs, market prices, and other variables that are inherently uncertain and extend several years beyond the scope of this proceeding.

Have you now had an opportunity to observe actual positive regulatory lag that does not depend on numerous assumptions?

A. Yes, I have. I observe that during March through June of 2026, considering only energy revenues, EMM experienced significant positive regulatory lag associated with Customer A.

Q. Have you now had an opportunity to review hourly load of EMM's LLPS customers?

A. Yes. Pursuant to Commission rule, EMM provided LLPS rate code hourly load *** [redacted] *** for the months of April 2026, May 2026, and June 2026.[4] That hourly load, in kWh, is graphed below:

***

[redacted]

***

[4] The Commission's rule, 20 CSR 4240-3.190(3) includes, "(A) Every electric utility shall accumulate the information described below and submit it monthly in EFIS on the last day of the month following the month to be reported... ...6. Total load for each hour by-... ...C. Retail load by-(I) Rate code if customers taking service on a rate code are metered at a consistent voltage; or (II) Rate schedule for each voltage of service offered within each rate schedule...."

Q. What did your review indicate?

A. I was able to calculate the value of LLPS load as purchased in the Day Ahead (DA) energy market. For the *** [redacted] *** kWh of LLPS load in April, May, and June, the market value of the required energy was *** [redacted] ***. This works out to an average of *** [redacted] *** per kWh.

For the month of June 2026, LLPS load had an average Day Ahead energy cost of *** [redacted] ***. For the month of May 2026, LLPS load had an average Day Ahead energy cost of *** [redacted] ***/kWh. For the month of April 2026, LLPS load had an average Day Ahead energy cost of *** [redacted] ***/kWh.

Q. How much positive regulatory lag resulted from energy sales during this period for EMM, related to Customer A?

A. For the three months for which hourly load information was provided, plus FAC recovery that will occur pursuant to the FAR under review in ER-2027-0032, EMM will experience positive regulatory lag of approximately *** [redacted] *** per kWh for each kWh of energy sold to Customer A, for a total of approximately *** [redacted] ***.

Q. Does that quantification consider revenue from Customer A for demand charges, grid charges, or customer charges?

A. No. Additional positive regulatory lag has resulted from those other rate elements. The quantification of energy-related regulatory lag is summarized in the table and graph below:

***

[redacted]

[redacted]

***

Q. Is the positive regulatory lag primarily caused because the energy rates for LLPS customers are too high?

A. No. The current LLPS energy rates are effectively a wash with the current and normalized level of energy expense to serve LLPS load. The positive regulatory lag is caused by the effective double-recovery of the cost for energy to serve LLPS customers (1) from the LLPS energy rate, and (2) then again from all customers in the form of the FAR.

Q. If Staff's recommended FAC "Option 2," had been in place during AP 22, how would the FAR differ from the FAR as it is currently calculated for AP 22 in ER-2027-0032?

A. If Option 2 had been in place during AP 22, the resulting recovery period FAR would be about $0.00028 per kWh[5] lower than that requested in ER-2027-0032, and as explained below, other customers would pay approximately *** [redacted] *** less through the FAC [6]

Q. *** [redacted] ***. Will LLPS customer growth fully offset the increases in FAR rates caused by LLPS customers and potentially benefit non-LLPS customers?

A. No. The level of growth required to fully offset the relative increases in FAR rates due to customer growth, especially on an ongoing basis, is simply not possible.

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[5] For purposes of this illustration, this calculation reflects only the difference in FAR calculation associated with hourly prorated energy expenses. Additional non-LLPS benefit will result from incorporation of adjustments related to monthly prorations of load-side SPP energy-related transactions, and monthly proration of load-side SPP demand-related transaction, as recommended in the Direct Testimony of Brooke Mastrogiannis, at pages 10 – 11.

[6] Because AP 22 results in a FAR that is overall negative, this discussion is somewhat complicated. Essentially, the FAR would be more negative if FAC Option 2 had been in place during AP 22, and the over-recovery during AP 22 would have been higher.

Q. Who will pay for the *** [redacted] *** in Day Ahead energy expenses incurred during AP 22 for Customer A?

A. While the recovery will ultimately depend on the percentage of total energy used by different customers, customers other than Customer A will pay the majority of the energy expenses incurred during AP 22 for Customer A. If Customer A uses *** [redacted] *** kWh during the recovery period and other customers use *** [redacted] ***[7] kWh during the recovery period, then Customer A will pay *** [redacted] ***, and other customers will collectively pay *** [redacted] ***.

Q. Will EMM lose the *** [redacted] *** absorbed in the example laid out above?

A. No. The LLPS energy rate during AP 22 was $0.02988 per kWh. As explained above, the LLPS average day ahead market energy expense during AP 22 was an average of *** [redacted] *** per kWh. Through normal LLPS energy rates, EMM has already recovered the cost of LLPS energy, plus *** [redacted] *** in marginal revenue above the cost of LLPS energy, prior to any FAC recoveries, from the energy rates alone. The above example demonstrates if Staff's FAC recommendation Option 2 had been in place during AP 22, it would not have resulted in an EMM revenue shortfall. However, the lack of Option 2 will result in a positive regulatory lag windfall of *** [redacted] *** in addition to the positive regulatory lag of the demand-based rates.

Q. Does Staff have any further recommendations on this issue?

---

[7] Using *** [redacted] *** demand at a *** [redacted] *** load factor results in Customer A annualized usage of *** [redacted] *** kWh.

A. Yes, LLPS service at each applicable voltage level should be a separate rate code from LPS service at the corresponding voltage levels, but out of an abundance of caution, I recommend that the Commission order EMM to continue to include LLPS hourly loads in its monthly reporting under 20 CSR 4240-3.190, separate from LPS hourly loads. The information provided under 20 CSR 4240-3.190 is available only to Commission Staff and the Office of the Public Counsel ("OPC").

Q. In her rebuttal testimony at pages 11-12, Ms. Foo includes the following exchange:

> Q. What is the overall concern with Option 2?
>
> A. Option 2 does not actually identify and remove the SPP costs caused by the Large Load Customers. Instead, it creates proxies for those costs and then removes the resulting allocated amounts from the FAC. Staff's proposal is also inconsistent with concerns Staff witness Lange raises regarding the use of generalized energy and demand information. Staff recognizes that the timing and coincidence of customer peaks matter for demand related calculations. Yet Option 2 attempts to allocate SPP costs using generalized customer energy and demand ratios that do not necessarily reflect the specific settlement determinants that caused those costs. It is difficult to reconcile Staff Lange's concerns with Option 2's assumption that aggregate monthly kWh and kW ratios provide a reasonable basis for assigning SPP settlement costs to Large Load Customers.

What is your response?

A. Staff understands from the Commission's order in EO-2025-0154 that the Commission determined that it was not appropriate to require a separate CP node for each LLPS customer, and is aware of the Commission decision that "[t]he Commission will not change the existing FAC tariff sheet until a rate case is filed."[8] This case is such a general rate case as is required for FAC modification, and Staff's FAC Option 2 is a reasonable balancing of these interests in that it relies on a reasonable balance of (1) easily-obtainable and easily-retained hourly data for the task of quantifying the amount of energy expense associated with LLPS load at a class level, (2) easily-obtainable and easily-retained monthly coincident peak information for SPP[9] bills assessed on peak demand,[10] and (3) easily-obtainable and easily-retained monthly total energy information for SPP bills assessed on energy usage.[11]

Q. In his rebuttal testimony at page 4, lines 18-20 Mr. Darrin R. Ives asks himself the question, "Staff's Option 2 to remove large loads from the FAC and Ms. Schaben's recommendation both assume the Company can identify the fuel and purchased power costs associated with a single LLPS customer. Is that assumption sound?"

Is this what Staff's Option 2 assumes?

A. No, it is not what Staff's FAC recommendation Option 2 assumes. Staff is not seeking that EMM rely on the Locational Marginal Price ("LMP") at the actual interconnection of the LLPS customer. Instead, Staff recognizes that the EMM load node LMP represents the market value of energy that has been transacted in that hour for

[8] See Report and Order in EO-2025-0154 at pages 41 -42.
[9] Southwest Power Pool (SPP).
[10] Only two numbers are required to prorate SPP demand-related expenses for these purposes, EMM peak at the time of the relevant SPP demand determinant, and LLPS class peak at the same time.
[11] Only two numbers are required to prorate SPP demand-related expenses for these purposes, EMM monthly energy usage, and LLPS class monthly energy usage.

all EMM customers. Staff's recommendation is to prorate the value of energy in every hour between LLPS customers, and all other customers. This is an exceedingly simple math problem of multiplying a column of LLPS class load by a column of EMM LMP node values. Mr. Ives' answer at page 4, line 22 – page 5, line 2 of his rebuttal testimony misrepresents the problem and Staff's solution in saying "[t]he Company forecasts and settles load with SPP at the aggregated settlement location level, and SPP commits and dispatches generation resources regionally on economics." Staff's position is not recommending nodal treatment of large loads, it is segregating a proration of energy expense based on actual market values and actual consumption by LLPS and non-LLPS customers in each hour.

Mr. Ives's testimony at page 6, lines 4–8 is misguided to an even greater degree. Mr. Ives includes this exchange,

> Q. What is the significance of attempting to isolate net fuel costs for large customers in this proceeding?
>
> A. The proposals here would change one element of a balanced package while leaving the other elements as approved. If the FAC element is re-examined, the re-examination should account for how it functions within the whole rather than testing it in isolation.

Staff is not proposing net fuel cost isolation, and to its knowledge, neither is OPC. Rather, Staff recommends energy value identification and proration.

Large Load Revenue, Usage, and Cost of Service

Q. In his rebuttal testimony at page 9, lines 20–23, Mr. Ives includes the following exchange:

> Q. How does the arrival of large load relate to the FAC sharing mechanism?
>
> A. Applied to variances driven by new large load rather than by procurement or dispatch decisions, the five percent FAC sharing functions less as an efficiency incentive than as a shareholder contribution toward the cost of serving new customers.

How do you respond?

A. This response ignores the recovery of revenue for new energy charges that occurs through the energy rate component of the LLPS rates, which is currently tariffed at $0.02988 per kWh for LLPS customers served at transmission voltage. In other words, the only way the FAC can result in a shareholder contribution toward the cost of serving new customers is if the per kWh rate for new customers is not set high enough to cover the expense of the wholesale value of energy for new energy sales. In other words, Mr. Ives' position is only accurate – and only in part – if the LLPS energy rate is too low.[12]

In her rebuttal testimony at page 5, lines 1-3, Ms. Nunn similarly testifies "Option 2 is flawed and unacceptable as it is contradictory to the agreements made in the setting of the LLPS rates and would leave the Company with no way to recover the related net fuel costs." This argument similarly presumes that LLPS energy rates are underpriced. If the LLPS energy rates are expected to equal or exceed the wholesale value of energy – which they have historically and will do in this case if adjusted appropriately – then the

[12] This relationship is acknowledged in the rebuttal testimony of Ms. Foo, at page 2, line 20 – page 3, line 3:

> Q. What are market prices and how do they impact variable fuel and purchase power expense?
> A. Market prices, also known as Locational Marginal Prices ("LMPs"), is the cost of supplying the next unit of electricity to a specific location on a transmission network. It is the market clearing price at which energy is bought and sold at each node, or Settlement Location ("SL"). In simplified terms, a generator sells power and receives revenues determined by the LMP at a generator SL. Electricity, whose cost is determined by the LMP at the load SL, is then purchased to serve the required load.

new revenue that EMM receives for selling a new kWh of energy provides adequate revenue to pay SPP for the value of that energy sold.

Q. Mr. Ives's recommendations to completely overhaul the EMM FAC are addressed in the surrebuttal testimony of Brooke Mastrogiannis, in which she recommends rejection. If Mr. Ives's recommendation were adopted over Staff's concerns, what modifications to energy rates would be required?

A. The value of the Net Base Energy Costs ("NBEC"), adjusted for voltage, would need to be subtracted from the energy rates of every customer in every class.

Q. Should that result in the LLPS energy rate dropping to zero?

A. It would not be reasonable for the LLPS energy rate to drop to zero under the circumstances described by Mr. Ives. Were that to be implemented, LLPS customers would not contribute to any cost of service not reflected in the FAC except for contributions provided under the customer charge and demand-based charges. This is particularly problematic because while, under EMM's proposal, additional cost of service would be allocated to Missouri on the basis of jurisdictional energy consumption LLPS customers would not contribute to recovery of that cost of service through energy rates.

Q. In his rebuttal testimony at page 9, lines 14–20, Mr. JP Meitner testifies that "SPP settlement charges result from the Company's integrated participation in the wholesale market and are not in direct proportion to an individual customer's share of Missouri jurisdictional energy." What is Staff's response?

A. For purposes of setting the overall cost of service and revenue requirement in this case, Staff is not opposed to Commission acceptance of EMM's representation that large loads will not increase EMM's cost of service related to transmission expense. In Staff's direct case, Staff offset the annualized and normalized revenue of Customer A by *** [redacted] *** million dollars and the annualized and normalized revenue of Customer B by *** [redacted] *** million dollars.

Q. What is FERC Order 668 netting?

A. FERC Order 668 netting is an accounting convention that details how utilities are to record the sums of the net values of hourly energy transactions for reporting purposes.

Q. How does FERC Order 668 netting relate to the cost of energy to serve load?

A. FERC Order 668 netting has no relationship to the cost of energy to serve load.

Q. What specifically does FERC Order 668 require for booking energy purchases and sales?

A. Order No. 668-A, issued in Docket No. RM04-12-001, on May 16, 2006, includes a section, "Clarification," which clarifies the portions of Order 668 relevant to the confusion at play in this case. It states:

> **Clarification**
> 13. In Order No. 668, the Commission adopted a net basis for accounting for and reporting energy transactions occurring in RTO-administered energy markets. Entities have inquired informally about (1) the proper way to net energy transactions when an entity participates in more than one RTO-administered energy market and (2) the proper basis for determining whether net hourly energy transactions are to be reported as a net sale or a net purchase. We take this opportunity to clarify the appropriate accounting for these transactions.

14. Some RTOs operate two energy markets; a day-ahead market and a real-time or balancing market. Entities that participate in both markets have requested clarification whether transactions occurring in each market should be separately netted for a given hour (as explained below, yes) or whether the transactions in the two markets should be combined for a given hour for netting purposes (as explained below, no).

15. Since RTO-administered energy markets are operated and settled separately, transactions occurring in each market should be separately netted for purposes of determining whether an entity is a net seller or purchaser in a given hour. For example, if an entity had net purchases of 12 megawatt hours in the *day-ahead* market in hour one of day one of the month and net sales of 10 megawatt hours in the *real-time* market in the same hour one of day one of the month, it would record a purchase of 12 megawatt hours in Account 555, Purchased Power, for the *day-ahead* market for that given hour and a sale of 10 megawatt hours in Account 447, Sales for Resale, for the *real-time* market for that given hour; the purchases and sales did not occur in the same market and so would not be netted.

16. Additionally, in each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account No. 447 or Account No. 555, respectively. For example, assume that an entity in the real-time market had net sales of 10 megawatt hours during *hour one* of day one of the month and net purchases of 15 megawatt hours during *hour six* and of 5 megawatt hours during *hour ten* of day one of the month. Assuming there were no other transactions during the month, the entity would report for the month for the real-time market 10 megawatt hours of sales in Account 447 and 20 megawatt hours of purchases in Account 555; the sales and purchases did not occur in the same hour and so would not be netted.

17. Entities have also requested clarification whether net hourly energy transactions should be classified as a net purchase or sale based on a net megawatt hour basis or a net dollar basis. Net megawatt hours should be used as the primary basis for determining whether a net purchase or sale has occurred. For example, assume for a given market in a given hour that an entity purchases 10 megawatt hours at $500 and sells 12 megawatt hours at $480 in the real-time market. The transactions occurring during this hour would be accounted for and reported as a net sale in Account 447 of 2 megawatt hours at a loss of $20.

> 18. However, in instances where the megawatt hours net to zero for a given market in a given hour, then the net hourly energy transactions should be classified as a net purchase or sale based on a net dollar basis. For example, assume for a given market in a given hour that an entity purchases 10 megawatt hours at $500 and sells 10 megawatt hours at $480. The transactions occurring during this hour would be accounted for and reported as a net purchase in Account 555 of zero megawatt hours at a cost of $20.

Q. Assume that the load LMP for a given hour is $30. Assume that Customer A uses 100 MWh and all other retail customers use 900 MWh. What is the cost of energy to serve load?

A. The cost of energy to serve load in that hour is $30,000.

Q. Assume that in the same hour, EMM did not operate any generation. How would that hour's transactions be recorded?

A. That hour's transaction would be recorded as a purchase of $30,000.

Q. Now, assume that EMM generates 999 MWh in that hour, and that the LMP at the generator is $30. How would that hour's transactions be recorded?

A. In that hour, more MWh were bought than were sold, so that hour's transactions would be recorded as a purchase of $30.

Q. Now, assume that EMM generates 1,001 MWh in that hour, and that the LMP at the generator is $30. How would that hour's transactions be recorded?

A. In that hour, more MWh were sold than were bought, so that hour's transactions would be recorded as a sale of $30.

Q. In the first scenario, what was the value of the energy consumed by Customer A?

A. The LMP for load in the first scenario was $30 per MWh, and Customer A required 100 MWh, so the value of energy to serve Customer A was $3,000.

Q. In the second scenario, what was the value of the energy consumed by Customer A?

A. The LMP for load in the second scenario was $30 per MWh, and Customer A required 100 MWh, so the value of energy to serve Customer A was $3,000.

Q. In the third scenario, what was the value of the energy consumed by Customer A?

A. The LMP for load in the third scenario was $30 per MWh, and Customer A required 100 MWh, so the value of energy to serve Customer A was $3,000.

Q. Is this issue confused by rebuttal testimonies in this case?

A. Yes. Dr. Berry devotes considerable attention to a theory that the cost of energy to serve a large load customer is actually the cost of fuel for a particular utility to generate additional energy, plus energy sale revenue and minus energy sale expense.

Q. Is there a term for the concept that Dr. Berry references?

A. Yes, this concept is known as net energy cost, or net fuel and purchased power expense. While that is how overall energy expenses and revenues for a vertically integrated regulated utility can be conceptualized in a regulatory context, it does not have bearing on the value of energy used by a given customer at a given location at a given point in time.

Q. Is Staff consistent in its use of LMPs for the value of energy in allocating cost of service and designing rates in electric rate cases?

A. Yes. For at least a decade, when reasonable class hourly load information is available, Staff has used the hourly load LMP multiplied by each class's hourly loads to allocate the cost of energy to serve each class in class cost of service studies.

Q. What is an LMP, aside from the market clearing price of economically and security constrained dispatch at a given location at a given time?

A. In addition to those characteristics, an LMP is an independent market-determined valuation of energy at that particular place and time. In other words, even if using the LMP as the energy valuation on the basis of its use in the actual underlying energy transaction were to be ignored, the LMP is still a reasonable valuation of the energy that is being consumed by a particular customer.

Q. Mr. Meitner includes the following exchange at page 7, lines 14-20:

> Q. Do you agree with Staff's position that 15-minute demand intervals are necessary to be able to annualize class loads, perform production cost modeling, and calculate jurisdictional allocation factors?
>
> A. No, I do not. Evergy has consistently produced model runs that do not require 15-minute demand intervals. Hourly loads are utilized in Evergy modeling and is consistent with the granularity that the SPP market requires. Anything requested beyond hourly granularity is not necessary and becomes infeasible very quickly.

Is Mr. Meitner's summary of Staff's position on this issue accurate?

A. No. Mr. Meitner mischaracterizes Staff's testimony. Staff's concern is not that 15-minute demand data for LLPS customers is required for production cost modeling or the other items he lists. Rather, Staff's position is that hourly load data is needed for the items listed by Mr. Meitner, and that 15-minute demand data is needed for customer revenue annualization.[13]

Allocated and Direct Revenues and Cost of Service

Q. Can you briefly explain jurisdictional allocations?

A. Yes. For a utility that operates under more than one jurisdiction, nearly every line of a cost of service calculation (like Staff's Accounting Schedules) is adjusted to apportion that rate base item, expense item, or revenue item, between the relevant jurisdictions.

Q. Is every line adjusted?

A. No. Some lines are treated as belonging to only one jurisdiction. For example, 100% of the disallowance ordered by the Missouri Commission related to Iatan is allocated to the Missouri jurisdiction, and 100% of the cumulative additional amortizations to preserve credit ratings that were billed to Missouri ratepayers to facilitate work at Iatan in the mid-2000s is allocated to the Missouri jurisdiction. For example, 100% of the cost of energy purchased from Missouri solar customer-generators is allocated to the Missouri jurisdiction, and some customer accounts expenses related to interest on deposits, interest on deposits, and similar items are calculated by jurisdiction and wholly allocated to the respective jurisdiction.[14]

Q. For its direct case, how did Staff treat revenues from Customer A?

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[13] See Claire M. Eubanks, PE direct testimony at pages 18 – 19.
[14] A corresponding decrease in the cost of service responsibility of the other applicable jurisdictions would generally not be reflected until the next applicable rate review in that jurisdiction.

A. For its direct case (filed in June 2026), as reflected in the "true-up plug," Staff calculated expected Customer A revenue for one year (based on the *** [redacted] *** Electric Service Agreement (ESA) dated *** [redacted] ***) and Staff calculated the expected cost of energy to serve Customer A for one year. Staff subtracted an estimate of the expected cost of energy (plus an estimate of additional expected transmission expenses) from the estimated expected revenue and allocated 100% of that new net revenue to the Missouri jurisdiction.

Q. What is Staff's recommended true-up treatment of Customer A revenues and expenses?

A. While the expense level will be adjusted to true-up to reflect Staff's true-up market prices calculations, Staff recommends the same treatment – calculation of net Customer A revenues.[15]

Q. Did Staff consider any alternative approaches?

A. Yes. Specifically, Staff considered (1) adjusting the hourly load profile reflected in Staff's fuel and purchased power modeling by adding an estimate of Customer A load to the hourly load, (2) adjusting the jurisdictional energy consumption used for the calculation of the jurisdictional energy allocator to include an estimate of Customer A load, and (3) adjusting the jurisdictional coincident demands in the demand allocator used for jurisdictional allocations to reflect an estimate of Customer A.

[15] As discussed in my Cost of Service Direct Testimony at pages 27 - 32, the revenue amount is subject to gross-up for the anticipated rate increase. However, that calculation is not relevant to the jurisdictional allocation subject at hand.

Staff determined that it was more reasonable to use an incremental revenue approach in this case rather than to make those adjustments.

Q. What certainty do we have concerning revenue from Customer A, and what certainty do we have concerning expenses to serve Customer A?

A. We are certain that Customer A will pay a minimum of *** [redacted] *** for each month of the summer billing season of Contract Year 1, and we are certain that Customer A will pay a minimum of *** [redacted] *** for each month of the non-summer billing season of Contract Year 1. The expenses to serve Customer A will vary between $0.00 for energy purchases if no energy is used and approximately *** [redacted] *** if the high end of the load factor range is achieved and a demand of *** [redacted] *** is maintained. However, as discussed in the section *Relationship of Energy Market Value to LLPS Energy Rate*, there is little to no direct margin on energy sales on the LLPS rates.[16] Meaning, no matter how much or how little energy is sold, it is unlikely that EMM will obtain significant additional net revenue from the energy sales to Customer A. In short, for Contract Year 1, EMM will obtain a minimum of *** [redacted] *** from Customer A on an annualized basis even if no energy is used, and demand-based revenues can only go up from there – that is certain. It is also certain that energy revenue and energy expense will effectively offset, regardless of the level of energy used by Customer A.

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[16] While significant positive regulatory lag will occur if FAC recovery of LLPS energy expenses continues, current LLPS energy rates are effectively a wash against the current and expected DA value of energy to serve LLPS load.

Q. How does the certainty of energy expense and Customer A revenue relate to the decision to use an incremental revenue approach in this case rather than to adjust the three items above?

A. Incorporating Customer A into the hourly load profile reflected in Staff's fuel and purchased power modeling and adjusting the jurisdictional coincident demands in the demand allocator used for jurisdictional allocations to reflect an estimate of Customer A coincident demand requires Staff to make assumptions about exactly how much energy Customer A will be using in each hour of the year. There is not sufficient information upon which to reasonably base such assumptions at this time. Similarly, incorporating Customer A into the jurisdictional demand allocator calculation requires Staff to make assumptions about exactly how much energy Customer A will be using in key hours of the year. Further, incorporating an estimate of Customer A coincident demand into the jurisdictional demand allocator calculation and incorporating an estimate of Customer A energy usage into the jurisdictional energy allocator could only be reasonable if similar adjustments were made for Kansas jurisdictional load growth, and Staff does not have information to make those offsetting adjustments.

Q. Could you provide further information about how Staff estimated Customer A energy expense and why Staff determined it was less reasonable to adjust the hourly load profile reflected in Staff's fuel and purchased power modeling by adding an estimate of Customer A load to the hourly load than to use an incremental revenue approach in this case?

A. Yes. First, it is important to understand that there is no available long-term hourly load shape for Customer A. To calculate either incremental energy expense outside of a production model, or to include Customer A in a production model, an hourly load shape must be assumed. For both direct and true-up, Staff relied on Evergy's most recently provided "Incremental Cost Analysis Study by Load Factor," for hourly load profiles.[17] Those load profiles are confidential, and reflect each hour in a year, but follow a repeated pattern based on the day of the week and the time of the day. A simple short example of Staff's direct (and true-up) calculation of load-weighted average $/MWh is provided below:

Hour	Market Price	Load Shape	Shape x Price	
1	$ 21.00	0.6	$ 12.60	
2	$ 22.00	0.7	$ 15.40	
3	$ 23.00	0.8	$ 18.40	
4	$ 24.00	0.9	$ 21.60	
5	$ 25.00	1	$ 25.00	
6	$ 24.00	0.9	$ 21.60	
7	$ 23.00	0.8	$ 18.40	
8	$ 22.00	0.7	$ 15.40	
9	$ 21.00	0.6	$ 12.60	
10	$ 20.00	0.6	$ 12.00	
		7.6	$ 173.00	$ 22.76

In this example, the market price for each hour is multiplied by the shape for each hour. The total product of Shape x Price is divided by the additive total of the shape

[17] File, "2025 Incremental Load Cost Analysis _CONF.xlsx," provided by email, "RE: [EXTERNAL]BEDR-2025-1636/1637 - EMM/EMW Eco Devo Riders: Request for Supporting Documentation [CONF]," from Anthony Westenkirchner to Tracy Johnson, J Luebbert, and Mark Johnson, on May 1, 2025, updated with prices provided in file, "CONF_2026 Incremental Load Cost Analysis_Workpaper.xlsx," provided by email to Travis Pringle related to BEDR-2026-1837, on or about June 10, 2026.

factors, and the result is the load-weighted average price of $22.76. If we assume the demand was 100 MW, applying 100 MW to the load shape produces total load of 760 MWh. 760 MWh multiplied by the $22.76 average price per MWh results in energy expense of $17,300.

However, to incorporate the calculation into the production cost model, the process would effectively be reversed with the same result reached. The process would be to multiply the Load Shape by the demand, to produce hourly loads. Then, to multiply those hourly loads by the Market Price.

Hour	Load	Market Price	Load x Price	
1	60	$ 21	$ 1,260	
2	70	$ 22	$ 1,540	
3	80	$ 23	$ 1,840	
4	90	$ 24	$ 2,160	
5	100	$ 25	$ 2,500	
6	90	$ 24	$ 2,160	
7	80	$ 23	$ 1,840	
8	70	$ 22	$ 1,540	
9	60	$ 21	$ 1,260	
10	60	$ 20	$ 1,200	
	760		$ 17,300	$ 22.76

This approach results in energy expense of $17,300, and an average price per MWh of $22.76. These are the exact same results.

Q. If the exact same results are reached, why does it matter which results are used?

A. There are two reasons. First, if the results are modeled externally to the production cost modeling, then direct allocation of the expense to Missouri is facilitated. If the results are modeled within the production cost modeling, then the expense would be shared between jurisdictions using the jurisdictional energy allocator as discussed below. Second, modeling the results within the production cost model would influence the results of the transmission sharing percentage calculation for the FAC. Finally, as will be discussed below, reflecting one calculation of net revenue versus pervasive adjustment helps to mitigate the risk of getting it wrong.

Q. In what way would the transmission sharing percentage be influenced?

A. The transmission sharing percentage is based on the results of FERC 668 hourly netting, discussed in the section, *Large Load Revenue, Usage, and Cost of Service*. While it is one thing to use the generic load shape for calculating an estimate of average energy expense, it is entirely another to incorporate the details of that load shape for each hour into the transmission sharing calculation. The information EMM has provided about Customer A's load factor is that *** [redacted] ***, presumably on an annual basis. Staff uses *** [redacted] *** because it is "good enough" and some estimate is needed to perform even the most basic calculations in this case. However, it is simply not reasonable to rely on those details at an hourly level. Drastically different transmission sharing percentage calculations will result if significant Customer A load aligns with summer peaks than if much of its usage occurs during autumn overnight hours, and there is simply no basis at this time to assume exactly where that load will fall down to the hour.

Q. What happens when Missouri's jurisdictional allocators go up?

A. Missouri's cost of service increases.

Q. Assuming that Customer A *** [redacted] ***, are Missouri customers other than Customer A going to pay higher rates if Customer A estimated usage is reflected in (1) the fuel and production cost model (2) the jurisdictional energy allocator, and (3) the jurisdictional demand allocator?

A. I don't know. The results cannot be known until all of the issues in this case have been resolved, and the increase applicable to Customer A rates is known.

Q. Can you provide an example of how these issues interrelate?

A. Yes. Provided below is a simplified and hypothetical cost of service calculation for total Evergy Metro, and for Missouri's jurisdictional cost of service calculation "A":

	Total Metro		**Missouri A**
Total Ratebase	$ 11,428,571,429		$ 5,575,824,176
Production Ratebase	$ 3,428,571,429	50.00%	$ 1,714,285,714
Transmission Ratebase	$ 2,285,714,286	52.50%	$ 1,200,000,000
Distribution Ratebase	$ 3,428,571,429	45.00%	$ 1,542,857,143
Other Ratebase	$ 2,285,714,286	48.94%	$ 1,118,681,319
Return on Ratebase and Income Taxes	$ 1,000,000,000		$ 487,884,615
Depreciation Expenses	$ 400,000,000	48.94%	$ 195,769,231
Purchased Power Expense	$ 600,000,000	55.00%	$ 330,000,000
Fuel Expense	$ 400,000,000	55.00%	$ 220,000,000
Energy Sales Revenue	$ 700,000,000	55.00%	$ 385,000,000
Other Expenses	$ 45,000,000	48.94%	$ 22,024,038
New Missouri Large Load Revenue			
New Missouri Large Load Expense			
	$ 1,745,000,000		$ 870,677,885
Average $/kWh:	**$ 0.08725**		**$ 0.07915**

Next, we will incorporate hypothetical new LLPS revenue, and hypothetical new LLPS expense, in Missouri jurisdictional cost of service calculation "B":

	Total Metro		Missouri A	Missouri B
Total Ratebase	$ 11,428,571,429		$ 5,575,824,176	$ 5,575,824,176
Production Ratebase	$ 3,428,571,429	50.00%	$ 1,714,285,714	$ 1,714,285,714
Transmission Ratebase	$ 2,285,714,286	52.50%	$ 1,200,000,000	$ 1,200,000,000
Distribution Ratebase	$ 3,428,571,429	45.00%	$ 1,542,857,143	$ 1,542,857,143
Other Ratebase	$ 2,285,714,286	48.94%	$ 1,118,681,319	$ 1,118,681,319
Return on Ratebase and Income Taxes	$ 1,000,000,000		$ 487,884,615	$ 487,884,615
Depreciation Expenses	$ 400,000,000	48.94%	$ 195,769,231	$ 195,769,231
Purchased Power Expense	$ 600,000,000	55.00%	$ 330,000,000	$ 330,000,000
Fuel Expense	$ 400,000,000	55.00%	$ 220,000,000	$ 220,000,000
Energy Sales Revenue	$ 700,000,000	55.00%	$ 385,000,000	$ 385,000,000
Other Expenses	$ 45,000,000	48.94%	$ 22,024,038	$ 22,024,038
New Missouri Large Load Revenue				$ 75,000,000
New Missouri Large Load Expense				$ 32,142,857
	$ 1,745,000,000		$ 870,677,885	$ 827,820,742
Average $/kWh:	**$ 0.08725**	$/kWh for Customers other than LLPS:	**$ 0.07915**	**$ 0.07526**

For Missouri jurisdictional cost of service scenario "C" the jurisdictional allocators are adjusted to reflect that fully hypothetical LLPS customer:

	Total Metro		Missouri A	Missouri B		Missouri C
Total Ratebase	$ 11,428,571,429		$ 5,575,824,176	$ 5,575,824,176		$ 5,877,789,445
Production Ratebase	$ 3,428,571,429	50.00%	$ 1,714,285,714	$ 1,714,285,714	53.82%	$ 1,845,331,283
Transmission Ratebase	$ 2,285,714,286	52.50%	$ 1,200,000,000	$ 1,200,000,000	57.09%	$ 1,304,906,346
Distribution Ratebase	$ 3,428,571,429	45.00%	$ 1,542,857,143	$ 1,542,857,143	45.00%	$ 1,542,857,143
Other Ratebase	$ 2,285,714,286	48.94%	$ 1,118,681,319	$ 1,118,681,319	51.83%	$ 1,184,694,673
Return on Ratebase and Income Taxes	$ 1,000,000,000		$ 487,884,615	$ 487,884,615		$ 514,306,576
Depreciation Expenses	$ 400,000,000	48.94%	$ 195,769,231	$ 195,769,231	51.83%	$ 207,321,568
Purchased Power Expense	$ 600,000,000	55.00%	$ 330,000,000	$ 330,000,000	60.36%	$ 362,142,857
Fuel Expense	$ 400,000,000	55.00%	$ 220,000,000	$ 220,000,000	60.36%	$ 241,428,571
Energy Sales Revenue	$ 700,000,000	55.00%	$ 385,000,000	$ 385,000,000	60.36%	$ 422,500,000
Other Expenses	$ 45,000,000	48.94%	$ 22,024,038	$ 22,024,038	51.83%	$ 23,323,676
New Missouri Large Load Revenue				$ 75,000,000	100.00%	$ 75,000,000
New Missouri Large Load Expense				$ 32,142,857	60.36%	$ 19,400,510
	$ 1,745,000,000		$ 870,677,885	$ 827,820,742		$ 870,423,759
Average $/kWh:	**$ 0.08725**	$/kWh for Customers other than LLPS:	**$ 0.07915**	**$ 0.07526**		**$ 0.07913**

In these particular scenarios, rates for Missouri customers who are not LLPS customers are higher if the jurisdictional load factors are adjusted and the new expense is shared jurisdictionally. But, in this scenario, rates for non-LLPS Missouri customers under "C" are still lower than if no LLPS customer is reflected in the case.

Q. Is this the result you would expect in this case?

A. I don't know. Provided below is the same set of scenarios, but with a change in the Total Metro expense level:

	Total Metro		Missouri A	Missouri B		Missouri C
Total Ratebase	$ 11,428,571,429		$ 5,575,824,176	$ 5,575,824,176		$ 5,877,789,445
Production Ratebase	$ 3,428,571,429	50.00%	$ 1,714,285,714	$ 1,714,285,714	53.82%	$ 1,845,331,283
Transmission Ratebase	$ 2,285,714,286	52.50%	$ 1,200,000,000	$ 1,200,000,000	57.09%	$ 1,304,906,346
Distribution Ratebase	$ 3,428,571,429	45.00%	$ 1,542,857,143	$ 1,542,857,143	45.00%	$ 1,542,857,143
Other Ratebase	$ 2,285,714,286	48.94%	$ 1,118,681,319	$ 1,118,681,319	51.83%	$ 1,184,694,673
Return on Ratebase and Income Taxes	$ 1,000,000,000		$ 487,884,615	$ 487,884,615		$ 514,306,576
Depreciation Expenses	$ 400,000,000	48.94%	$ 195,769,231	$ 195,769,231	51.83%	$ 207,321,568
Purchased Power Expense	$ 600,000,000	55.00%	$ 330,000,000	$ 330,000,000	60.36%	$ 362,142,857
Fuel Expense	$ 400,000,000	55.00%	$ 220,000,000	$ 220,000,000	60.36%	$ 241,428,571
Energy Sales Revenue	$ 700,000,000	55.00%	$ 385,000,000	$ 385,000,000	60.36%	$ 422,500,000
Other Expenses	$ 60,000,000	48.94%	$ 29,365,385	$ 29,365,385	51.83%	$ 31,098,235
New Missouri Large Load Revenue				$ 75,000,000	100.00%	$ 75,000,000
New Missouri Large Load Expense				$ 32,142,857	60.36%	$ 19,400,510
	$ 1,760,000,000		$ 878,019,231	$ 835,162,088		$ 878,198,318
Average $/kWh:	**$ 0.08800**	$/kWh for Customers other than LLPS:	**$ 0.07982**	**$ 0.07592**		**$ 0.07984**

Q. Are there scenarios where Missouri ratepayers (other than LLPS) pay lower overall rates due to reflecting the new customer in the allocators?

A. I'm sure there are. The point is that even with known and fixed energy levels and allocator calculations, the net impact on other customers can vary wildly.

Q. Are Customer A annualized energy levels and related allocator calculations known in this case?

A. No. While the ESA contract demands are known, and while EMM has provided Staff information on a wide range of expected load factors, the level of certainty that would typically be required to create an annualized customer energy calculation is not present in this case.[18]

SURREBUTTAL ON NON-RESIDENTIAL NON-LIGHTING RATE STRUCTURES AND DESIGN

Q. In her rebuttal testimony at page 16, line 14 through page 17, line 14, Ms. York testifies on behalf of MECG:

> Q. DO YOU AGREE WITH STAFF'S RECOMMENDATION THAT EACH RESTRUCTURED CLASS RECOVER APPROXIMATELY 15% OF ITS REVENUE FROM BILLING DEMAND CHARGES?
>
> A. Not as applied to the LGS and LPS classes, and not as a uniform target across classes. In my Direct Testimony, I explained that a large majority of the Company's revenue requirement is fixed, capacity-related cost, and that rate design should, therefore, recover a greater share of fixed costs through demand charges. I recommended increasing the LGS and LPS demand charges by 1.5 times the class average increase and the energy charges by 0.5 times the class average increase because the Company's proposed energy rates recover far more of the revenue requirement than the energy-related share of the cost of service. Staff's own data shows that billing demand charges currently provide approximately 12% of LGS class revenue and approximately 17% of LPS class revenue. Staff's recommended 15% target would move the LGS class modestly toward greater demand recovery, which is directionally consistent with my recommendation. For the LPS class, however, the 15% target would reduce the share of revenue recovered through demand charges below the current 17% level. Reducing demand-based recovery for the LPS class moves the rate structure away from cost causation, not toward it, because it shifts recovery of fixed, capacity-related costs onto volumetric energy charges. I recommend that the Commission place greater weight on demand charges for the LGS and LPS classes, consistent with my Direct Testimony, rather than adopt a uniform 15% demand recovery target that would reduce demand-based recovery for the LPS class.

What is Staff's response?

[18] For purposes of FAC Option 1, an average level of annualized energy is used, balancing the risk of inaccuracy between EMM shareholders and ratepayers.

A. In the absence of a usable CCOS based on appropriate class composition to inform the demand charges, Staff prefers consistency among classes. However, Staff is not opposed to retaining the 12% and 17% demand revenue percentages currently resulting from the current class compositions for the LGS[19] and LPS classes, respectively. Any increases to the demand charges must be limited to:

> (1) minimize the overall customer impact at a time when customer classes are changing, the measure of demand is changing, and the relevant period for demand is changing, and,
>
> (2) ensure that upon completion of the customer migration study and calculation of appropriate determinants, care should be taken to ensure that the energy charges for any class are not less than the hourly load LMP multiplied by each class's hourly loads.

Q. Throughout Ms. York's testimony, are her assertions concerning system planning requirements, cost of service causation, and energy provision to retail customers accurate and reasonable?

A. No, they are not. Ms. York's view of these subjects is several decades behind, fails to account for the integrated energy market in which EMM participates, and fails to account for the interaction of renewable generation with capacity planning and cost of service regulation.

Q. At page 11, lines 13-18, Bradley D. Lutz testifies that he is "…disappointed by Staff's recommendation to change the seasons and the timing periods from demand and energy pricing used within the Company rate designs, then recommending the Company perform a new customer migration and determinants study starting on

[19] Large General Service (LGS).

July 14th, so that new rates can be calculated in this case. I am surprised by the Staff recommendation to delay the rate structure implementations for nearly a year after the conclusion of this case."

First, what is Staff's recommendation to change the seasons used by EMM?

A. Staff did not recommend to change the seasons used by EMM.

Q. In addition to allowing time to produce and distribute customer education and bill impact materials, is there specific consideration to timing that should be observed with respect to implementing the rate structure changes?

A. Yes. Staff's recommendation to delay the rate structure implementation to November of 2026 would also avoid implementing a rate structure change during the summer months which are generally billed at higher rates for many elements. Staff is not opposed to implementing the rate structure change with the October billing month so that the summer billing months of June – September are avoided, assuming that customer education materials can be prepared and disseminated on that time frame.

Q. In his rebuttal testimony at page 33, lines 7–10, Mr. Graham A. Jaynes includes the following exchange:

> Q. Does Staff oppose removal of Reactive Demand for the MGS and LGS classes?
>
> A. No, not in principle however Staff expresses the same need for study in relationship to other rate design changes to establish the appropriate restructured rates. For that reason Staff proposes maintaining the status- quo through the implementation delay.

Does Staff, in fact, oppose removal of reactive demand charges for the MGS[20] and LGS classes?

A. Yes. Staff discussed this recommendation on page 34 of the Staff Rate Design Report.[21]

As grid infrastructure such as static VAR compensation becomes increasingly necessary in order to maintain voltage support in areas with insufficient rotating mass generation, and as rapidly fluctuating loads with significant inductive load requirements increase grid penetration, reactive demand is becoming a more and more significant consideration in designing utility rate structures.

SURREBUTTAL ON RESIDENTIAL CUSTOMER CHARGE

Q. In his rebuttal testimony at page 10, lines 8–14, Mr. Jaynes includes the following exchange:

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

What is Staff's response?

[20] Medium General Service (MGS).
[21] "Staff recommends that upon completion of the customer migration and determinants study, as scaled, EMM calculates rates that recover approximately $668,113 across the MGS, LGS, and LPS customer classes from reactive demand, maintaining the general proportionality of reactive demand rates that exists across the customer classes currently. The rate determined for LPS customers should also be applied to LLPS customers." Staff Rate Design Report, page 34, lines 13–17.

A. It is true that in its rebuttal testimony Staff criticizes EMM's CCOS for the methods used in classifying distribution cost of service, functionalizing production cost of service, and allocating distribution, production, and administrative and general cost of service. However, what makes the Company's CCOS wholly unreliable – as opposed to just bad or inaccurate – is (1) the use of the study in this case where class migrations are a significant issue, (2) incorporation of new cost of service and new large loads are significant issues, and (3) failing to appropriately address either of those issues undermines the usefulness of the study.

As it relates to the Staff's partial customer charge study, as discussed in greater detail in the Surrebuttal testimony of Marina Gonzales, Staff's review of the cost of service of the EMM residential customer charge was not intended to develop a full customer charge calculation upon which to base a new customer charge recommendation, it was rather a sanity check on whether the cost of service of meters and services, that otherwise vary with the addition of a customer, necessitated an increase to the current $12.00 customer charge. Staff's review indicated that such an increase is not necessary at this time and recommends retaining the current residential customer charge at $12.00.

TRUE-UP ON LARGE LOADS

Staff's Recommended Revenue Imputations

Q. Can you summarize Staff's treatment of Customer A and Customer B for purposes of true-up in this case?

A. Staff recommends that the Commission offset the Missouri-jurisdictional cost of service for non-LLPS customers by incorporating 100% of normalized and annualized energy and transmission expense to serve Customer A and 100% of annualized Customer A revenue (grossed up for the anticipated rate increase).

Staff recommends the Commission rely on the annualized load and revenue described in the true-up direct of Amanda Rucker. Staff has incorporated Customer B, at a normalized and annualized level, into its LPS revenue and billing determinant quantifications. This incorporates Customer B into the NSI, transmission sharing percentage, and Staff's true up case in whole, to the same extent as any other retail customer.[22]

Q. Based on EMM's bills to Customer A, what were Customer A's characteristics during the true up period?

A. Customer A's bills are attached as Highly Confidential Schedule SLKL-td1. Customer A's usage and demand observed in those bills, along with a calculation of monthly load factor and a summary of charges found in those bills are summarized below:

***

[redacted]

***

[22] While the actual hourly energy consumption of Customer B is not known, the degree of uncertainty this inserts into other calculations is significantly smaller given the relative size of the customers.

Q. If EMM had calculated Customer A's bills correctly, what would those bills have been?

A. If calculated correctly, those bills would have been for the amounts set out in the table below:

***

[redacted]

***

Relationship of Energy Market Value to LLPS Energy Rate

Q. What is Staff's estimated level of DA energy expense to serve EMM's LLPS load, as of true-up, on a per kWh basis?

A. Using Staff's true-up market prices, for the EMM load node, and a *** [redacted] *** year-round load factor, the DA energy value is *** [redacted] *** per kWh. The monthly average $/MWh based on Staff's true-up market prices and the EMM load shape by load factor are provided by month in the table below.[23]

Load Shape	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	April	May	June	Simple Average	Day-Weighted Average
20% LF	$33.02	$32.10	$27.25	$27.74	$33.59	$40.95	$39.24	$29.86	$28.50	$44.14	$32.33	$31.80	$33.38	$33.40
30% LF	$31.14	$30.47	$26.06	$26.53	$31.93	$38.99	$38.79	$29.21	$26.39	$42.07	$31.01	$30.68	$31.94	$31.96
40% LF	$30.83	$30.44	$25.72	$26.30	$31.41	$38.89	$39.07	$29.52	$26.19	$41.34	$30.53	$30.37	$31.72	$31.73
50% LF	$30.16	$29.94	$25.48	$25.97	$31.08	$38.40	$38.95	$29.37	$25.61	$40.52	$30.03	$29.85	$31.28	$31.29
60% LF	$28.95	$28.87	$25.15	$25.36	$30.64	$37.46	$38.66	$28.94	$24.54	$39.07	$29.25	$28.94	$30.49	$30.49
70% LF	$28.14	$28.15	$24.93	$24.94	$30.37	$36.79	$38.42	$28.61	$23.81	$38.14	$28.77	$28.36	$29.95	$29.96
80% LF	$27.99	$28.08	$24.89	$24.88	$30.30	$36.75	$38.44	$28.63	$23.73	$37.95	$28.66	$28.22	$29.88	$29.88
90% LF	$27.76	$27.88	$24.87	$24.81	$30.31	$36.59	$38.45	$28.60	$23.61	$37.59	$28.46	$28.03	$29.75	$29.75
100% LF	$26.68	$26.95	$24.38	$24.13	$29.76	$35.78	$38.10	$28.14	$22.60	$36.38	$27.76	$27.16	$28.98	$28.99

[23] This calculation was made consistent with approach and the load shapes used in Staff's direct.

Q. How does the current LLPS energy rate relate to the value of DA market energy for load?

A. The current LLPS energy rate is essentially a wash with the DA market value for load, on an average $/kWh basis. While actual results will vary with actual energy market prices and actual LLPS customer energy usage patterns, it is reasonable to conclude that there is little to no direct margin on energy sales on the LLPS rates.[24] Meaning, no matter how much or how little energy is sold, it is unlikely that EMM will obtain significant additional net revenue from the energy sales to Customer A at the current LPS rate levels.

Q. For Staff's direct, Staff used an assumed level of Customer A annualized usage of *** [redacted] *** kWh, calculated based on *** [redacted] *** demand at a *** [redacted] *** load factor. Using those characteristics and assuming a 15% rate increase, what net energy revenues would be produced by Customer A under increased LLPS energy rates?

A. *** [redacted] ***. The graph below illustrates the approximate level of net revenue that would result from the Customer A characteristics described above at the range of LLPS energy rates from the current LLPS energy rate to a 15% increase in the LLPS energy rate:

[24] This conclusion concerns the LLPS energy rate only. Significant positive regulatory lag will accrue to EMM's benefit through the combination of LLPS energy rates and FAC recovery of the energy expense for providing service to LLPS customers.

***

[redacted]

***

Q. What level of incremental transmission expenses does Staff reflect in its true-up case as an offset to incremental LLPS revenue?

A. For purposes of setting the overall cost of service and revenue requirement in this case, Staff is not opposed to Commission acceptance of EMM's representation that large loads will not increase EMM's cost of service related to transmission expense.[25]

Q. What is Staff's true-up recommendation concerning incremental revenue from energy sales to Customer A?

[25] In his rebuttal testimony at page 9, lines 14–20, Mr. Meitner testifies that "SPP settlement charges result from the Company's integrated participation in the wholesale market and are not in direct proportion to an individual customer's share of Missouri jurisdictional energy."

A. Staff's true-up recommendation is that the Commission assume that energy revenue and energy expense will effectively offset. Reliance on this assumption will reduce the complexity of the Commission's resolution of this case.

Customer A Revenue and Recommended Net Revenue Requirement Increase

Q. As of June 30, 2026, what is known about the revenue of Customer A?

A. As of June 30, 2026, it is known that, based on the EMM LLPS tariff and the Customer A Electric Service Agreement, as amended, Customer A *** [redacted] ***.

Q. Have you calculated 12 months of EMM bills to Customer A associated with permutations of those characteristics, and setting aside energy charges, at current customer charge, demand charge, and grid charge rates?

A. Yes.

Q. What is the minimum level of revenue that EMM will bill Customer A under the EMM LLPS tariff, and the ESA, as amended, based on the contract demand level in place as June 2026, the end of the update period?

A. *** [redacted] *** based on 12 months of revenue calculated using the minimum demand of *** [redacted] *** MW for each of 12 months, calculated as 80% of the Year 1 contract demand of *** [redacted] *** MW.

Q. What is the level of revenue that EMM will bill Customer A under the EMM LLPS tariff, and the ESA, as amended, based on the contract demand level in place as of June 2026, the end of the update period?

A. *** [redacted] *** based on 12 months of revenue calculated using the Year 1 contract demand of *** [redacted] *** MW for each of the 12 months. This is the revenue level Staff uses for its true-up calculations.

Q. What is the minimum level of revenue that EMM will bill Customer A under the EMM LLPS tariff, and the ESA, as amended, based on the known contract demand levels in place for 12 months as of June 2026, the end of the update period?

A. *** [redacted] *** based on an annualization of *** [redacted] *** months of revenue calculated using the minimum demand of *** [redacted] *** MW for each of the remaining *** [redacted] *** months of contract Year 1, calculated as 80% of the Year 1 contract demand of *** [redacted] *** MW, and *** [redacted] *** months of revenue calculated using the minimum demand of *** [redacted] *** MW for the remaining *** [redacted] *** months of a year of annualized revenues, calculated as 80% of the Year 2 contract demand of *** [redacted] *** MW.

Q. What is the level of revenue that EMM will bill Customer A under the EMM LLPS tariff, and the ESA, as amended, based on the known contract demand levels in place for 12 months as of June 2026, the end of the update period?

A. *** [redacted] *** based on an annualization of *** [redacted] *** months of revenue calculated using the Year 1 contract demand of *** [redacted] *** MW for each of the remaining *** [redacted] *** months of contract Year 1, and *** [redacted] *** months of revenue calculated using the Year 2 contract demand of *** [redacted] *** MW for the remaining *** [redacted] *** months of a year of annualized revenues.

The contract demand levels and the monthly bills for the customer charge, grid charge, and demand charge for each of these permutations are set out in the graph below.[26]

***

[redacted]

***

Q. Which of these permutations does Staff recommend?

[26] Summer demand rates are higher than non-summer demand rates, which is why the monthly bill trends up for the final month of the graph.

A. Ultimately, this is a policy matter for the Commission. Staff has prepared its True-up Case reflecting Option 2, which relies on an annualization of contract demand of *** [redacted] *** MW for *** [redacted] *** months. The annual quantification (at current rates) of each permutation is set out in the graph below:

***

[redacted]

***

Q. If the Commission orders Staff's recommended increase consistent with Staff's true-up recommendation, what level of Customer A revenues will be provided to offset the otherwise applicable cost of service to non-LLPS Missouri ratepayers?

A. Adjusted for Staff's recommended increase in this case, that amount is *** [redacted] ***.

Q. Can you explain how that amount was calculated?

A. Yes. LLPS revenue at current rates is *** [redacted] *** excluding energy revenue. Existing adjustable non-LLPS rate revenues are $902,081,598. Together, this results in total starting adjustable revenues of *** [redacted] ***. Staff's recommended increase to total revenue requirement at true-up, excluding LLPS revenue, is $68,815,926, at the midpoint recommendation. This results in total target adjustable revenues of *** [redacted] ***, an increase of *** [redacted] *** or *** [redacted] *** %.

Staff applied that *** [redacted] *** % increase equally to each class's starting revenues, including LLPS. Those calculations result in the pre- EDI[27] level of imputed LLPS revenue of *** [redacted] ***, and are shown in the table below. The EDI reallocation and factor-up are also shown in the table below.[28]

***

[redacted]

***

[27] Economic Development Incentive (EDI).

[28] While the EDI reallocation will slightly increase LLPS rates, that increase offsets the reduction in revenue due to EDI and is not properly includable in the imputed LLPS revenue calculation for purposes of setting the overall net revenue requirement.

Staff's Recommended FAC Base Calculation Information

Q. Was Customer A's load reflected in the Staff's true-up fuel run?

A. No. As discussed in Staff's direct testimony, the actual hours of Customer A load cannot be reasonably normalized at this time.

Q. For use in calculating FAC Option 1, did you estimate the incremental energy expense associated with obtaining Day Ahead energy to serve Customer A?

A. Yes, I calculated those amounts for the usage levels discussed above, using Staff's true-up market prices, prepared by Staff Expert Justin Tevie. Using Staff's true-up market prices, for the EMM load node, and a *** [redacted] *** year-round load factor, the DA energy value is *** [redacted] *** per kWh. Consistent with Staff's direct, for purposes of FAC Option 1 calculations if ordered by the Commission, using *** [redacted] *** demand at a *** [redacted] *** load factor results in an assumed level of Customer A annualized usage of *** [redacted] *** kWh, and an annualized energy expense level of *** [redacted] ***.

Q. What adjustments should be made to the FAC under Staff FAC Option 1 if ordered by the Commission?

A. The Missouri Jurisdictional FAC base would be increased by annualized DA energy expense in the amount of *** [redacted] ***. For purposes of adjusting the FAC base if the Commission orders FAC Option 1, Staff is not opposed to Commission acceptance of EMM's representation that large loads will not increase EMM's cost of service related to transmission expense.[29]

Q. What adjustment would be made to NSI to implement FAC Option 1?

A. An addition of *** [redacted] *** kWh of Missouri jurisdictional energy is necessary if the Commission orders FAC Option 1.[30]

<u>TESTIMONY CORRECTIONS</u>

Q. Do you have any corrections to your rebuttal testimony?

A. Yes. Graham Jaynes alerted me to an error in my rebuttal testimony related to an estimate of the revenue associated with waiving the customer charge associated with LIHEAP[31] recipients. While I updated the testimony for the count of LIHEAP recipients when that information was provided, I inadvertently failed to update the dollar values from an earlier plug calculation that relied on 10,000 residential customers. The correct valuation is that if the customer charge is waived for 12,000 customers, the annual revenue not recovered from those customer charges is roughly $1.7 million at Staff's recommended customer charge level, and approximately $2 million at the EMM requested customer charge level.

[29] In his rebuttal testimony at page 9, lines 14–20, Mr. Meitner testifies that "SPP settlement charges result from the Company's integrated participation in the wholesale market and are not in direct proportion to an individual customer's share of Missouri jurisdictional energy."
[30] Note, in her rebuttal testimony at page 4, lines 10 – 12, Linda Nunn indicates EMM's support for FAC Option 1.
[31] Low Income Home Energy Assistance Program (LIHEAP).

Also, in my rebuttal testimony at page 71, line 18, concerning the recovery of revenue shortfall from an Income Eligible program, the language is excessively confusing. The exchange should read:

> Q. Could it also be reasonable to treat the avoided revenue as a program expense that is included in the cost of service calculation?
>
> A. Yes.

Q. Do you have a correction to the Staff Rate Design Report?

A. Yes. At page 45, the recommended tariff language for the Critical Peak Rate (CPR), Option 2, reflected inappropriate rounding. The recommended language should read, "If the DA-LMP has exceeded $100 in each hour of a given operating day and is $100 or more in each hour of the subsequent operating day, EMM shall issue a CPR notice for the next day, for all hours in that day. The CPR will be $0.025 per kWh."

Also, it was brought to Staff's attention that the load data reflected in Schedule 4 to the Staff Rate Design Report reflected a slightly different load shape due to the application of loss factors. The variations are minor and do not impact Staff's recommended non-residential, non-lighting, non-LLPS rate structures. A corrected version is attached to this testimony as public Schedule SLKL-s1.

<u>CONCLUSION</u>

Q. Does this conclude your Surrebuttal / True-up Direct testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

AFFIDAVIT OF 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 / True-Up Direct 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 8th day of September 2026.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2029
Commission Number: 12412070

D. Suzie Mankin
Notary Public

	0	off peak or exclude
	1	on peak
Hour beginning	2	highest rate

REVISED WITH LOSS ADJUSTMENTS CORRECTED

Summer	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
Demand Period	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Energy Price Period	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	2	1	1	1
Peak																8	4	4						
System Load	75%	71%	67%	63%	61%	61%	62%	64%	67%	71%	76%	81%	85%	90%	94%	97%	99%	100%	100%	98%	95%	91%	87%	81%
Energy Prices	28%	25%	21%	19%	19%	21%	25%	29%	35%	45%	50%	55%	63%	71%	80%	87%	96%	100%	93%	83%	69%	57%	47%	37%

Non Summer	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
Demand Period	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Energy Price Period	0	0	0	0	0	0	1	2	2	2	2	2	1	1	1	2	2	2	2	2	2	1	1	1
Non Summer Peak								11	3	1	1					1	6	4	4	-	1			
Winter Peak								9	1	1	1					-	-	1	3	-	-			
Non Summer Load	84%	82%	81%	80%	81%	82%	85%	88%	90%	90%	90%	89%	90%	91%	91%	91%	92%	93%	94%	93%	92%	91%	89%	86%
N.S. Energy Price	32%	39%	36%	37%	38%	42%	53%	65%	70%	74%	81%	75%	69%	66%	64%	63%	64%	69%	78%	76%	70%	64%	55%	46%
Winter Load	92%	92%	90%	91%	92%	94%	97%	100%	100%	99%	99%	96%	97%	96%	96%	96%	96%	98%	99%	99%	98%	97%	95%	93%
Winter Energy Price	43%	59%	56%	59%	59%	63%	76%	91%	95%	96%	100%	94%	84%	79%	74%	69%	69%	74%	88%	88%	83%	79%	70%	61%

NSI	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
NonSummer	393,306	386,888	378,206	377,131	378,391	385,189	398,953	412,907	420,534	422,555	423,265	419,487	425,127	426,100	426,541	427,864	431,778	438,274	441,202	438,316	434,049	428,783	418,547	404,788
True Winter	217,169	215,086	212,524	214,364	216,484	221,025	228,255	233,859	234,906	233,357	231,395	224,488	227,967	226,535	225,143	224,719	226,271	230,714	232,821	231,884	230,635	228,168	223,542	218,947
Summer	229,166	214,975	202,522	193,161	187,150	185,221	189,211	196,010	205,530	217,382	230,783	245,925	260,347	273,857	285,787	294,736	302,105	303,921	304,541	298,606	287,872	277,248	265,953	248,118

Hourly Avg NSI	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
NonSummer	49,163	48,361	47,276	47,141	47,299	48,149	49,869	51,613	52,567	52,819	52,908	52,436	53,141	53,263	53,318	53,483	53,972	54,784	55,150	54,790	54,256	53,598	52,318	50,599
True Winter	54,292	53,772	53,131	53,591	54,121	55,256	57,064	58,465	58,727	58,339	57,849	56,122	56,992	56,634	56,286	56,180	56,568	57,679	58,205	57,971	57,659	57,042	55,885	54,737
Summer	57,291	53,744	50,630	48,290	46,788	46,305	47,303	49,003	51,382	54,346	57,696	61,481	65,087	68,464	71,447	73,684	75,526	75,980	76,135	74,651	71,968	69,312	66,488	62,030

SPP Peak Counts	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
NonSummer	-	-	-	-	-	-	-	11	3	1	1	-	-	-	-	1	6	4	4	-	1	-	-	-
True Winter	-	-	-	-	-	-	-	9	1	1	1	-	-	-	-	-	-	1	3	-	-	-	-	-
Summer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	4	4	-	-	-	-	-	-

LMP	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
NonSummer	$ 20.97	$ 25.93	$ 23.89	$ 24.16	$ 24.77	$ 27.48	$ 34.59	$ 42.82	$ 46.14	$ 48.90	$ 52.96	$ 49.57	$ 45.22	$ 43.52	$ 42.33	$ 41.16	$ 41.76	$ 45.28	$ 51.03	$ 49.64	$ 46.03	$ 42.19	$ 35.88	$ 30.02
True Winter	$ 28.30	$ 38.92	$ 37.10	$ 38.54	$ 38.99	$ 41.68	$ 50.23	$ 59.53	$ 62.52	$ 62.80	$ 65.71	$ 62.05	$ 55.50	$ 51.95	$ 48.50	$ 45.58	$ 45.15	$ 48.95	$ 57.84	$ 57.88	$ 54.66	$ 51.73	$ 46.14	$ 40.24
Summer	$ 19.73	$ 17.71	$ 15.14	$ 13.89	$ 13.68	$ 14.99	$ 17.87	$ 20.42	$ 24.92	$ 31.90	$ 35.94	$ 39.51	$ 44.88	$ 50.70	$ 57.15	$ 62.36	$ 68.26	$ 71.34	$ 66.45	$ 58.99	$ 49.07	$ 40.36	$ 33.36	$ 26.16

Case No. ER-2026-0143
Schedule SLKL-s1

Case No. ER-2026-0143

SCHEDULE SLKL-td1

HAS BEEN DEEMED

CONFIDENTIAL

IN ITS ENTIRETY