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Issue(s):	*Large Loads, Class Cost of Service, Rate Design, Tariffs, Income Eligible Rate*
Witness:	*Sarah L.K. Lange*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Rebuttal Testimony*
Case No.:	*ER-2026-0143*
Date Testimony Prepared:	*August 11, 2026*

MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF / RATE DESIGN DEPARTMENT

REBUTTAL TESTIMONY

OF

SARAH L.K. LANGE

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO

CASE NO. ER-2026-0143

Jefferson City, Missouri
August 2026

*** Denotes Highly Confidential Information ***
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Q. Are you the same Sarah Lange who filed revenue requirement direct testimony, rate design direct testimony, and contributed to Staff's Rate Design Report?

A. Yes.

SUMMARY

Q. What is the purpose of this rebuttal testimony?

A. In this testimony, I will:

- Explain how EMM[1] failed to normalize Customer A revenues in its direct case and rate design testimony,
- Explain how EMM has underbilled Customer A,
- Respond to direct recommendations of parties concerning EMM's LLPS[2] rates, address whether EMM's LLPS rates comply with Missouri statute, and respond to parties' recommended mechanisms concerning LLPS customers,
- Address the double-recovery that would be caused by EMM's request to include long term capacity contracts in the FAC, and address base factor calculations,
- Update the recommended Critical Peak Rate for applicability to customers who have opted out of AMI metering,
- Address concerns with EMM's CCCOS study,[3]

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[1] Evergy Missouri Metro
[2] Large Load Power Service
[3] Class Cost of Service

- Address concerns with EMM's requested rate structures, customer migration plans, and tariff changes, and respond to the class cost of service and revenue responsibility positions of other parties,

- Recommend allocation of the cost of providing any Income Eligible Rate the Commission may authorize in this case.

LLPS REVENUE AND COST OF SERVICE IN EMM'S DIRECT CASE

Q. In his direct testimony at page 17, Kevin Gunn testifies that, "Stated plainly, as a result of the customer protections included in the LLPS rate, Evergy Missouri Metro customers are already seeing benefits from data centers in this region. While no customers are currently served on the LLPS rate, Evergy Missouri Metro reduced its proposed rate request by $25 million based on expected revenue from new large data center operations in 2026. This is a clear and immediate benefit for Evergy Missouri Metro customers. In addition, the Company expects to update the rate request this summer. In that update, additional revenue may be available at that time to be included from one or more data centers benefiting existing customers by further reducing this rate request." Is the $25 million adjustment stated by Mr. Gunn reflected in EMM's workpapers?

A. In part. Based on my review, EMM adjusted its case by including approximately $25.2 million in LLPS revenue,[4] but it appears that amount is offset by additional fuel expenses, resulting in a net adjustment of ***[redacted]*** million.[5]

Q. EMM filed its direct case on February 6, 2026, prior to the effective date of the LLPS tariff. Are there current LLPS customers?

[4] Graham Jaynes direct testimony, Schedule GAJ-10.
[5] Graham Jaynes workpaper, "CONFIDENTIAL 26 MO Metro CCOS Current Class Structure."

A. Yes. While EMM's direct case included adjustments for expected LLPS activity, because there was no LLPS tariff during the test year, there were no LLPS customers. There is now an LLPS customer, *** [redacted] *** ("Customer A").

Q. When did EMM know the rates and terms of service that would be applicable to LLPS customers?

A. The rates applicable to LLPS customers were approved in the Commission's Report and Order in EO-2025-0154, which was approved November 13, 2025.

Q. As of February 6, 2026, what was the contractual demand known to EMM for Customer A?

A. The execution date of the "Large Load Power Service, Schedule LLPS Service Agreement," between EMM and *** [redacted] *** for service to the customer's site known as *** [redacted] *** was *** [redacted] ***. In that Electric Service Agreement ("ESA"), the year 1 "Contract Capacity," demand is stated as *** [redacted] *** with provision for *** [redacted] ***.

Q. Using the known EMM LLPS rates, the known ESA contract capacity for year one, the known minimum bill calculation in the LLPS terms, and the standard annualization approach of 12 months of data, what is the minimum amount of revenue that can be expected from Customer A, if it consumes no energy and has no demand?

A. *** [redacted] ***

LLPS in EMM's CCOS

Q. In its direct case, how much revenue did EMM include associated with expected LLPS activity.

A. In the EMM CCOS, EMM reflects *** [redacted] *** of revenue for the LLPS Subclass, which at this time consists solely of Customer A. The revenue EMM assumes for Customer A in its direct CCOS is *** [redacted] *** per kWh. [6]

Q. How much revenue requirement did EMM allocate to LLPS in its direct CCOS?

A. EMM allocated *** [redacted] *** of revenue requirement to LLPS. This amount consists entirely of "Production Fuel." For purposes of the EMM CCOS, "Production Fuel," is EMM's calculation of "Fuel (Other)" operations expense for Steam Production account 501 of $137,075,343, and EMM's calculation of "Fuel" operations expense for Nuclear Power Generation account 518 of $16,727,846. This total of $153,803,189 of "Production Fuel" expense is allocated to the customer classes in the EMM CCOS on the basis of the energy consumption in MWh that EMM modeled for each customer class for each month times the average fuel expenses per MWh EMM modeled for each month.

The total cost of service EMM allocates to LLPS in its direct CCOS is *** [redacted] *** per kWh.

[6] In his direct testimony at page 5, EMM witness Graham Jaynes testifies that for its revenue requirement calculations, EMM included $16.1 million in LLPS revenue as a pro forma adjustment, and additional revenues of $9.1 million are reflected. In its CCOS, EMM reflected *** [redacted] *** in LLPS subclass revenue, and included an "LLPS Premium" of $3.8 million. This "LLPS Premium" appears to be calculated as related to factoring up LLPS revenues for the increase EMM requested in this case.

Q. How much annual energy does EMM use in its CCOS for calculations related to Customer A?

A. EMM's calculations related to LLPS are based on a total of *** [redacted] *** MWh for the twelve month period.

Q. Is the level of energy consumption EMM reflected in its CCOS for LLPS consistent with the level of energy consumption that should be expected for Customer A under its Electric Service Agreement terms in effect as of the end of the true-up period?

A. No. Customer A's contract demand as of the true-up period is ***[redacted] *** MW, and EMM stated that it expects Customer A's to have a load factor of *** [redacted] *** to ***[redacted] ***.[7] Applying those load factors to that level of demand results in expected annual energy consumption of *** [redacted] *** to *** [redacted] *** MWh for a year of service. EMM's CCOS indicated an expected level of consumption for June of 2026 of ***[redacted] *** MWh. Relying on this level of monthly consumption to roughly annualize for a year results in *** [redacted] *** MWh for a 12 month period.

***

[redacted]

***

[7] EMM Response to Staff DR 226.

Q. Does EMM's CCOS reflect the energy cost to serve Customer A as Customer A's energy for a month multiplied by the average fuel cost per MWh that EMM calculated for that month?

A. No. That is how EMM calculated the allocator that it used for "Production Fuel." EMM applied that allocator to a different total, as described above. The results for multiplying EMM's calculated average fuel cost per MWh for each month to different energy consumption scenarios are set out below:

***

[redacted]

***

Q. The product of EMM's monthly load in MWh for Customer A and EMM's fuel cost per MWh is *** [redacted] ***. Why did EMM allocate only *** [redacted] *** of "Projection Fuel" expense to Customer A?

A. Based on the values in its workpapers, it appears that EMM did include wind purchased power contract expenses and gas and oil fuel expenses in its calculation of the Fuel allocator, but it did not allocate any purchased power expenses, gas expenses, or oil expenses (fuel or otherwise) to Customer A.

Q. Did EMM allocate any market energy expenses to Customer A?

A. No.[8]

Q. Did EMM allocate any Renewable Energy Standards compliance costs to Customer A?

A. No.

Q. Did EMM allocate any SPP or MISO expenses to Customer A?

A. No.

Q. Did EMM allocate any of the costs of owning any coal, nuclear, gas, wind, or solar plants to Customer A?

A. No.

Q. Did EMM allocate any of the costs of operating any coal, nuclear, gas, wind, or solar plants to Customer A?

A. Excluding the partial fuel allocation discussed above, no.

Q. Is any aspect of EMM's treatment of Customer A in its CCOS reasonable?

A. No. The Commission should not rely on any aspect of EMM's treatment of Customer A in the EMM CCOS as reliable for any purpose. While Staff disagrees with various aspects of EMM's allocation decisions in its CCOS as described below and in the

[8] The EMM production model relies on energy market values for load that result in a simple average of $0.02640 per kWh. The market value of energy is the cost that is caused by serving a kWh of energy to any given customer, as opposed to the fuel cost that EMM incurs in response to dispatch orders for load anywhere in the SPP footprint.

Rebuttal Testimony of Marina Gonzales, with regard to Customer A, EMM did not allocate any cost of service associated with generation plant ownership, transmission ownership or operation, energy market expenses, SPP participation, PISA election,[9] or the ordinary administrative and overhead operation of a utility. EMM allocated only a non-representative amount of "generation fuel" to the cost of service allocated to Customer A.

Q. Is the EMM CCOS study useful to the Commission in determining compliance under Section 393.130.7, RSMo., which requires that tariff provisions applicable to customers who are reasonably projected to have above an annual peak demand of one hundred megawatts or more "reasonably ensure such customers' rates will reflect the customers' representative share of the costs incurred to serve the customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers."[10]

A. No. In consultation with Staff counsel, Staff has concluded that the EMM CCOS study does not reasonably reflect the share of costs incurred to serve LLPS customers.

Q. Does EMM's inappropriate treatment of the LLPS subclass in its CCOS further undermine EMM's CCOS results as a whole?

A. Yes. While the EMM CCOS is not otherwise reliable, the EMM CCOS as a whole is further undermined by EMM's inclusion of the minimal "Production Fuel"

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[9] Plant in Service Accounting, under which EMM is allowed to negate negative regulatory lag on qualifying assets.
[10] Section 393.130.7, RSMo.

expense of *** [redacted] *** and the disproportionate revenue of *** [redacted] *** in the LPS class. This has the effect of unreasonably increasing the net revenue of the LPS class in the EMM CCOS by $18,152,752.

Q. Is Staff's criticism that EMM did not know in February what a customer's demands and usage would be in March, April, May and June?

A. No. Staff's criticism is that it is counter productive that EMM conducted a CCOS that was distorted by partial incorporation of partial information related to LLPS activity. And Staff is obligated to inform the Commission that the EMM CCOS study does not include LLPS activity that is on an appropriate scale to be reasonably representative of the actual LLPS activity that is known through the ESA with Customer A, nor does the EMM CCOS include allocations of cost of service that are representative either of the LLPS activity assumed in the CCOS, nor Customer A.

Minimum Bill Calculation

Q. Has EMM appropriately calculated the minimum bill under the LLPS tariff?

A. No. EMM has underbilled LLPS customers and the EMM method of calculating the LLPS minimum bill is not compliant with the LLPS tariff, in that it deducts from the bill the amounts billed under the energy charge, the Demand Side Investment Mechanism (DSIM) charge, and the Fuel Adjustment Clause (FAC) charge.

Q. Are you aware of the characterization of the "Minimum Monthly Bill," in the Commission's publication, "Utility Tariffs for Large Load Customers in Missouri", attached as Schedule SLKL-r1?

A. Yes. It summarizes the Minimum Monthly Bill as, "Each large-load customer bill will include the sum of all applicable charges, including a monthly demand charge set at 80% of the agreed upon rate."

Q. Is that characterization accurate as it applies to EMM's LLPS tariff?

A. Yes, it is.

Q. Is EMM's calculation of Customer A's minimum bill consistent with that characterization?

A. No, it is not. The LLPS tariff states:

> MINIMUM MONTHLY BILL
> Customers taking service under Schedule LLPS shall be subject to a Minimum Monthly Bill that includes and is the sum of each of the following charges:
> 1. Demand Charge;
> 2. Customer Charge;
> 3. Grid Charge;
> 4. Reactive Demand Adjustment;
> 5. Other Demand-Based Riders approved by the Commission in the future; and,
> 6. Cost Stabilization Rider.
>
> The Customer's Minimum Demand shall be used to determine these charges.

EMM's response to Staff DR 415, attached as Highly Confidential Schedule SLKL-r2 includes the following explanation:

> *** [redacted]. ***

Q. Can you explain the inconsistency between the tariff provision and the EMM practice?

A. Yes. Rather than use the minimum demand to calculate the minimum demand-related charges, EMM nets out any revenue from energy sales (including the tariffed energy rate, the DSIM rate, and the FAC rate) against the minimum bill. This practice effectively allows Customer A to use how much energy they want, whenever they want, while paying exactly the same bill, so long as they do not exceed the minimum demand.

Q. Can you quantify the underrecovery?

A. Yes. For the months of March, April, May, and June of 2026, EMM has underbilled Customer A by *** [redacted] ***, as set out in the table below:

***

[redacted]

***

Going forward, *** [redacted]

[redacted] ***.

Response to Google

Q. In her June 30 direct testimony beginning at page 8, Dr. Berry provides her opinions concerning credit risks and possible increases to investor-required returns associated with large loads. Does any Staff analysis apply a premium to the returns required from LLPS customers to account for any additional credit risk associated with LLPS customers?

A. No.

Sharing Mechanism

Q. In her June 30 direct testimony beginning at page 11, line 11, Dr. Berry testifies, "[w]hen a utility experiences rapid, significant post-test-year load growth, its actual revenues can grow much faster than its recognized cost of service. Under Schedule LLPS, these new large load customers will be paying rates that reflect a premium above the basic cost to serve." Do you agree?

A. I do agree that customer growth can provide significant positive regulatory lag to the benefit of the utility. That positive regulatory lag can be offset in whole or in part by additions to the cost of service that are required to serve that customer growth. In this case, given the current LLPS rates and the expected cost of obtaining additional capacity required to serve LLPS customers, I cannot agree with Dr. Berry's conclusion that "these new large load customers will be paying rates that reflect a premium above the basic cost to serve."

Q. If you conclude that the rates LLPS customers will be paying are not too high, do you also conclude that other customers are adequately protected from the cost of service increases caused by new large load customers?

A. No, I do not. Under the current regulatory framework, the Commission is the safeguard to ensure that other customers are protected. In future cases, potentially including rate complaint cases to be brought by Staff or other parties, it will be incumbent on the Commission to balance:

- the positive regulatory lag EMM receives from LLPS customer growth, against
- the mechanisms that allow EMM to pass the consequences of negative regulatory lag on to other customers, where such lag is associated with increases in EMM's cost of service caused by LLPS customers.

Q. What mechanisms allow EMM to pass the financial impacts of what would otherwise be negative regulatory lag to customers?

A. In this context, the FAC is the main mechanism. To the extent Construction Work in Progress ("CWIP") recovery may be authorized for generation facilities built to serve large loads, that is another such mechanism.[11]

Q. Beginning at page 12 line 16 of her June 30 testimony, Dr. Berry alludes to adoption of earnings sharing mechanisms to hedge the "the possibility that Evergy's actual revenues from Schedule LLPS could outpace its approved revenue requirement

[11] PISA is also a mechanism that allows EMM to pass the financial impacts of what would otherwise be negative regulatory lag to its customers, although there are limits on what assets may be lawfully included in PISA when those assets enable customer growth.

outside of the historic test year."[12] She specifically offers a proposed mechanism under which:

> [W]ould use a two-tiered structure that builds upon an initial "deadband"—a buffer zone where no sharing occurs—as follows:
>
> a. 100% Utility Retention (Deadband): Evergy would retain 100% of all earnings up to 25 basis points above the authorized ROE approved in this case.
>
> b. 75% / 25% Balanced Sharing: Any earnings beyond that 25-basis-point deadband would be shared, with 75% credited to ratepayers to support bill affordability and 25% retained by Evergy.[13]

What is Staff's response?

A. Staff generally will not seek to disturb the Commission's rejection of a sharing mechanism in EO-2025-0154. However, if the Commission were to order such a sharing mechanism, the interaction of the FAC and the manner in which new generation construction is accounted for would need to be carefully considered to ensure that the mechanism is meaningful. Further, Staff recommends that any resulting sharing amounts would be better retained as a regulatory liability account held to offset the balance of generation units constructed to serve large loads.

Q. How does Dr. Berry's proposal compare to the sharing mechanism recommended by Greg Meyer, on behalf of MECG, in his direct testimony?

A. Mr. Meyer's recommendation is more easily implemented and is more straightforward. His recommendation is that EMM file an annual report detailing the revenues received and additional costs caused by LLPS customers. To the extent that

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[12] At pages 25-26 of his direct testimony, OPC witness Ronald Nelson recommends that a mechanism similar to that approved by the Commission for Ameren Missouri in ET-2025-0184, be ordered for EMM.
[13] Dr. Berry June 30 direct testimony, page 13 line 15 – page 14 line 3.

the additional revenues minus the additional cost is greater than the level of LLPS net revenue assumed in the case, Mr. Meyer recommends the difference be retained in a regulatory liability account for treatment in a future rate case.

Cost to Serve Large Loads

Q. In her July 14 testimony, Dr. Berry opines that "the amount of large load included in this rate case is very small and has no associated fixed costs, so there is little cost support for increasing LLPS rates beyond the increase already reflected in the settled rates,"[14] and Dr. Berry goes on to state:

> I recommend that the Commission consider and balance these critical factors affecting ratepayers and shareholders when determining the final LLPS rate:
>
> - The negotiated terms established in the 2025 LLPS Settlement;
> - The substantial revenue premium LLPS customers pay over LPS rates; and
> - The impact that further LLPS rate increases will have on the excess revenues collected due to expected rapid load growth during the new rate-effective period.
>
> Balancing these factors, I recommend that the Commission reject Evergy's proposed increase to LLPS rates and not approve any increase to LLPS rates at this time. [15]

Do you agree with Dr. Berry's recommendation?

A. No. While I do agree that rapid load growth will result in additional positive regulatory lag for EMM, a better solution is not to limit the rates applicable to LLPS, but rather to reliably estimate the net impact of that growth and reflect it in the calculation of

[14] Dr. Berry July 14 direct testimony, page 6 line 23 – page 7 line 3.
[15] Dr. Berry July 14 direct testimony, page 7 line 12 – 19.

rates applicable to all customers, as I recommended in my June 30 testimony. Staff recommends that the LLPS rates be increased by the same percentage increase as the rates applicable to all other EMM customers in this case.

Q. Do you agree with Dr. Berry that the amount of large load in this case has no associated fixed costs?

A. No. As discussed above, the EMM CCOS is wholly insufficient for determining compliance under Section 393.130.7, RSMo., which requires that tariff provisions applicable to customers who are reasonably projected to have above an annual peak demand of one hundred megawatts or more "reasonably ensure such customers' rates will reflect the customers' representative share of the costs incurred to serve the customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers."[16] Staff agrees that EMM failed to allocate fixed costs (or a reasonable approximation of variable costs) to LLPS customers in the EMM CCOS, but that is not the measure of whether LLPS rates are adequate and the extent to which they should be increased in this proceeding.

Q. EMM's fuel workpapers reflect a simple average value of energy to serve load of $0.02640/kWh. A simple average valuation evenly weights the price assumed by EMM in each and every hour, and would therefore reflect EMM's valuation of the value of the energy to serve a customer with a 100% load factor. It is reasonable to assume that the value of a customer with a load factor of less than 100% will be greater than $0.02640/kWh. The LLPS rate for each kWh is $0.02988. Do the current LLPS rates

[16] Section 393.130.7, RSMo.

provide revenue at or in excess of the market value of energy that EMM is selling to that LLPS customer?

A. If EMM's energy value estimates are relied on, it is reasonable to assume that the revenue an LLPS customer provides through its energy charge ranges from very slightly in excess of the market value of energy to inadequate to cover the market value of energy.

Q. Does Dr. Berry address the market cost of energy to serve LLPS load?

A. No.

Q. Does Dr. Berry address renewable compliance costs for LLPS customers?

A. No.

Q. Does Dr. Berry address the current cost of capacity for LLPS customers?

A. No.

Cost of Capacity to Serve LLPS Customers

Q. What is the summer 2026 SPP Planning Reserve Margin (PRM) requirement?

A. It is 16%. The SPP Quarterly Update to the Commission provided May 28, 2026, is attached as schedule SLKL-r3.

Q. The current contract demand for Customer A is *** [redacted] ***. Using the current LLPS demand-based rates, how much demand-based revenue would Customer A contribute for 12 months of service at the current level of contract demand?

A. *** [redacted] *** If the LLPS rates are increased consistent with Staff's recommended 3.64% increase, that amount would increase to *** [redacted] ***.

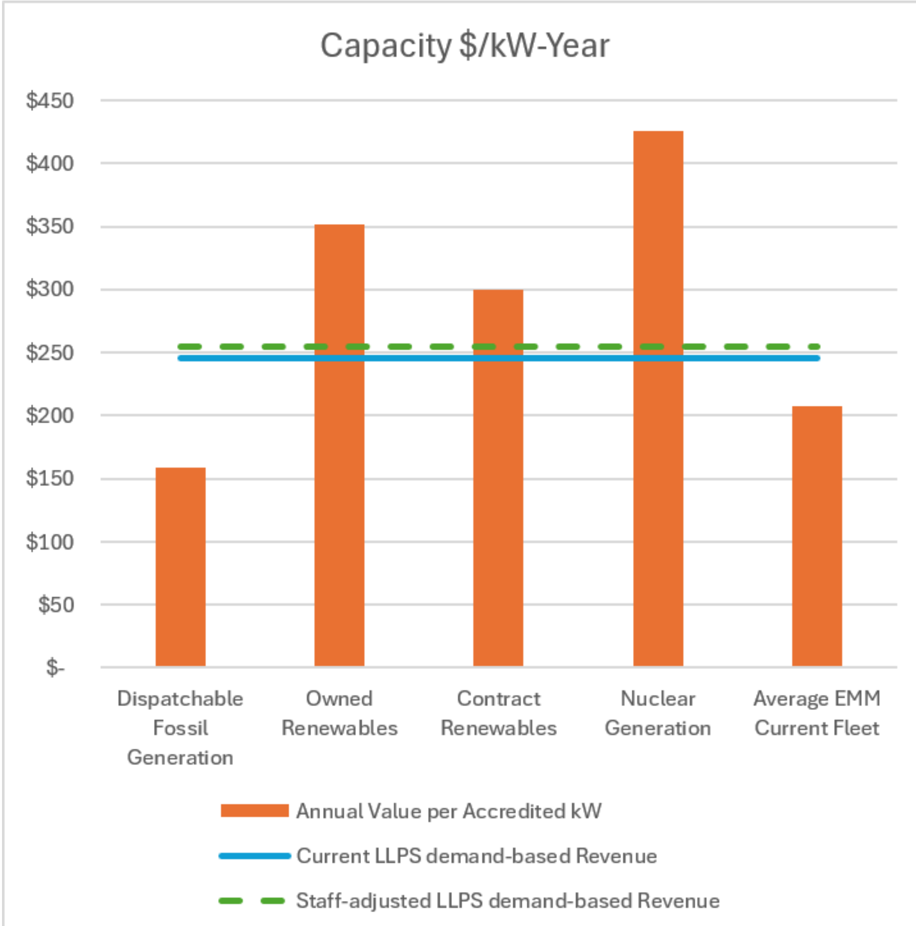
Q. In EMM's 2026 update to its Integrated Resource Plan, EO-2026-0188, what adjustment does EMM apply to peak load for the summer 2026 reserve margin, and using that margin, how many MW are required for Customer A for capacity purposes at this time?

A. EMM's 2026 update uses a reserve margin of 7.059%. Applying this factor to the Customer A year 1 contract demand of *** [redacted] *** MW, results in a requirement of *** [redacted] ***. The required margin is subject to change in future periods and Customer A's *** [redacted] ***.

Q. Please provide a comparison of the $/kW-Year cost of service values of summer accredited capacity for current EMM generation resources, compared to the current and Staff-recommended LLPS demand rates on a PRM-adjusted $/kW-Year basis, assuming that demand is consistent month to month.[17]

A. The $/kW-Year cost of service values of summer accredited capacity are presented below. The values below do not include fuel.[18]

[17] If demand is not consistent month to month, the $/kW-Year revenue produced will be lower.
[18] The contract renewables expense includes both capacity and energy.



Q. Have you reviewed the expected cost of new generation?

A. Yes. I have reviewed EMM's current CCN for Mullin Creek 2, the subject of pending case EA-2026-0154 and included those cost of service values in the graph and table provided below. The values provided for Mullin Creek 2 are average of the CWIP and AFUDC scenarios provided by EMM in response to DR 7 in EA-2026-0154:[19]

[19] For purposes of this testimony, the accredited capacity used for the Mullin Creek 2 calculation is the value EMM relies upon in IRP related filings, which is **[redacted] ** MW.

** [redacted] **

** [redacted] **

Q. What is the approximate transmission cost of service per kW?

A. In his direct testimony, J Luebbert calculates an additive cost per kW of approximately $3.4058 per kW-Month.[20] This equates to around $40 per kW-Year if demand is consistent in each month. Adjusting for expected incremental transmission expenses reduces the LLPS demand-based revenue under current rates to around $206 per kW-Year, and the Staff-recommended increased LLPS demand-based revenues to around $214 per kW-Year, if demand is consistent each month.

Q. Can you summarize your response to Dr. Berry's position that LLPS rates should not be increased in this case?

A. Yes. Depending on the timing and consistency of usage by LLPS customers, the revenue provided from LLPS energy rates will be more or less a wash, based on a simple average of EMM's estimate of the value of energy to serve load. The demand rates paid by LLPS customers do exceed the current average cost of EMM to own generation on a $/kW basis, but those costs are expected to increase significantly going forward.

Q. Do the LLPS demand-based rates provide a level of recovery that contributes meaningfully to "fixed" cost recovery?

A. The LLPS demand-based rates provide revenues that exceed a one-for-one allocation of the current cost of owning EMM's generation fleet on a $/kW year basis, assuming that an LLPS customer has consistent demand in every month.

[20] Note, this amount does not address the current transmission-related cost of service, for which EMM did not allocate any responsibility in its CCOS studies.

The LLPS demand-based rate is not expected to cover the additional fixed cost of service that will be caused by the addition of Mullin Creek 2.

Q. What value for capacity did the Brattle Group use in designing EMM's restructured rates?

A. As stated in page 7 of the Brattle study, attached to Graham Jaynes direct testimony, "We used a marginal cost of generation capacity of $298/kW-year based on Evergy's 2028 combined cycle gas turbine costs."

Q. Setting aside (1) FAC-related issues, (2) network upgrade related issues,[21] and (3) the potential recovery of CWIP in this case associated with Mullin Creek 2,[22] what rates should the Commission set for LLPS customers in this case to comply with 393.130.7?

A. For this case, because Mullin Creek 2 is not included in rates, Staff recommends that the Commission increase LLPS rates by an equal percentage as all other classes.

However, the environment for LLPS customers is competitive among utilities, and the addition of LLPS customers causes increases in fixed costs. If the Commission determines it is appropriate to recognize this relationship and set the rates for additive competitive load to generally equate to the increases in cost of service that will be caused by the additive competitive load, as would be expected of any firm operating in a free

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[21] The "Ratepayer Protection Pledge," provided by EMM to Staff by email of Thursday, July 23, 2026, 4:56 PM, reflects EMM's agreement "to protect American consumers from price hikes due to data center energy and infrastructure requirements, and lower electricity costs for consumers in the long term, including by… … Companies cover all new delivery upgrades required to service their data centers, including network upgrade costs, ensuring those expenses are not passed on to ordinary households."
[22] Discussed in the direct testimony of Matt Young.

market, those rates should be increased by approximately ** [redacted] **, to amounts representative of the cost of owning Mullin Creek 2. For LLPS service at transmission voltages, the comparative charges are set out below:

**

[redacted]

**

The monthly bills, annual bills, and annual average $/kWh amounts for a customer with a consistent *** [redacted] *** MW demand and a consistent *** [redacted] *** monthly load factor are set out below, calculated using currently-tariffed LLPS rates, and the rates that result from the "Revised Demand" rates set out above:

***

[redacted]

***

***

[redacted]

***

This is an average increase in the LLPS rates of about $0.0114/kWh for a customer with the indicated characteristics. A customer who contributes less to summer peak demands would experience a lower average increase. A customer with a higher load factor would experience a lower average increase, and a customer with a lower load factor would experience a higher average increase.

Note, this quantification does not include a representative estimate of demand-based transmission expenses as a component of the demand rate, nor does it include an incremental increase in capacity cost responsibility associated with renewable generation.

LARGE LOADS AND FAC

Long Term Capacity

Q. Will including long term capacity contracts in the FAC result in double recovery of the cost of those contracts?

A. Yes.

Q. Will EMM need additional capacity to serve new LLPS customers or additional demand from Customer A?

A. Yes.

Q. Will EMM's total cost of service increase to buy or build additional capacity to serve new LLPS customers or additional demand from Customer A?

A. Yes.

Q. Does EMM need to include that additional capacity cost in the FAC to be made whole?

A. No.

Q. Why not?

A. At the conclusion of this case, EMM's rates will be set to recover the cost of service of its existing generation based on selling the amount of energy and demand that is included in the normalized determinants in this case. If EMM's system demands increase from the level reflected in normalized determinants, that means EMM is selling more energy to its customers and experiencing higher customer demands.

For purposes of this discussion, consider a utility with an annual cost of service of $1,000,000. Of that cost of service $600,000 is for owning and operating one 600 kW power plant, and $400,000 is for the market value of energy, which is $0.10 per kWh. There are no other costs. This example utility has one customer, rates were set using that customer's demand of 600 kW, and energy requirement of 4,000,000 kWh. The customer pays $1,000,000 per year for its service (4,000,000 kWh x $0.1/kWh = $400,000. 600 kW (annual) x $100 $/kW (annual) = $600,000).

If that utility gets a second customer with a demand of 300 kW and annual energy consumption of 2,000,000 kWh, the utility will have to get more capacity, and will have to pay for more energy. The utility will also be getting another $500,000 in annual revenue. (2,000,000 kWh x $0.1/kWh = $200,000. 300 kW (annual) x $100 $/kW (annual) = $300,000).

While the utility will experience an additional $200,000 in energy expenses, it will receive another $200,000 in energy revenue. The utility will also effectively get a "budget" of $300,000 to meet the customer's new capacity needs.[23]

Q. How does this example relate to EMM's request to include long term capacity contracts in its FAC?

A. If EMM needs a new capacity contract, it is because EMM has increased customer demand. If EMM has increased customer demand, that means EMM has increased revenues.

Q. What if the new revenues from the LLPS demand charges do not fully offset the cost of capacity to serve new LLPS load?

A. Staff has two responses – the first is that a Missouri utility is not guaranteed a given return, and if EMM finds it necessary to file a rate case, it may do so, or it may continue to balance the negative and positive regulatory lags as it determines is appropriate. The second is that the EMM LLPS tariff provides EMM with the ability to bill LLPS customers for Interim Capacity. If the LLPS revenue from the LLPS rates are insufficient for the cost of long term capacity contracts to serve new LLPS loads, then the appropriate mechanism for EMM's recovery of those expenses is through a charge to LLPS customers for Interim Capacity, not the FAC.

[23] This hypothetical and discussion ignore the issue of double recovery that can occur through the FAC as discussed extensively by Staff in this case.

Updated Base Factor – Correction for Administrative Charges

Q. Did the information you provided to Brooke Mastrogiannis for calculation of the FAC base factor include an error?

A. Yes, in the provision of estimated FAC recoverable expenses for Customer A and incremental Customer B load, I neglected to incorporate Staff's position that the costs in SPP Schedule 1A-1, 1A-2, 1A-3 and 1A-4 (Tariff Administration Service) and SPP Schedule 12 (FERC Assessment) should not flow through the FAC.

Q. Have you updated these calculations to remove these items?

A. Yes. Staff expert J Luebbert provided a revised $/kW and $/kWh amounts excluding charges from these schedules, ($3.1907/kW and $0.00/kWh, respectively), and I used those revised amounts to provide the level of incremental transmission expense to include in the applicable FAC base factor to Staff expert Brooke Mastrogiannis.

LLPS-Only Base Factor

Q. If the Commission accepts OPC witness Angela Schaben's recommendation to create an LLPS only FAC, what is Staff's calculation of the appropriate base factor?

A. I am unable to calculate a base factor that incorporates the LLPS responsibility for real time variations and the expenses associated with required ancillary services. Using the Staff's DA LMP for the value of energy, the load factors described in my June 30, 2026, direct testimony, and the SPP transmission expense values provided above, a reasonable base factor for an LLPS-Only FAC would be $0.030965.

*** [redacted] ***

Q. Is this calculation reduced by revenue produced from the sale of energy into the wholesale market?

A. No, it is not. This calculation also does not include fuel expense to generate any energy sold into the wholesale market.

Q. Would it be reasonable to include revenue produced from the sale of energy into the wholesale market, generated from ancillary services, or produced from transmission equipment under SPP's functional control?

A. No. This calculation also excludes the fuel that would be used to create the energy made available for sale into through the wholesale market. In Staff's opinion, a reasonable LLPS-only FAC base factor, if ordered by the Commission, would include only LLPS energy expenses, and a reasonable proration of FAC-recoverable transmission expenses.[24]

[24] Additional refinements would be possible if LLPS customers' energy transactions were settled at a separate node from the balance of EMM's load.

CRITICAL PEAK RATE

Q. Have you become aware of an issue with the Critical Peak Rate recommendation you provided in the Staff Rate Design Report?

A. Yes. In that recommendation, I overlooked the ability of residential customers to avoid AMI metering. To account for the AMI opt-out provisions of 20 CSR 4240-10.035, I recommend that any residential customer not metered with AMI metering be billed $3.00 per event day, under either Option 1 or Option 2. Appropriate tariff language would be, "in the event a residential customer has opted-out of AMI metering, the CPR rate applicable to such customer is $3.00 per event day."

CLASS COST OF SERVICE

Q. Are there overall concerns which undermine the reliability of the EMM CCOS?

A. Yes. Any CCOS study bears the liability of being of a snapshot in time. However, of particular concern in this case are the following:

- Distortions caused by LLPS treatments discussed above,
- Distortions caused by the customer migration sequencing described in section "Restructuring and Migrating Customers" beginning on page 24 of the CCOS Report which undermine the usefulness of the Proposed Class Study, and the inapplicability of the Current Class Study to customer classes going forward,
- Concern with the reliability of the demands relied upon in the study due to concerns with the thoroughness of interval data caused by EMM's inability to obtain all meter reads of all customers for a given interval to be summed,
- The failure to reasonably study the cost efficiency of programs such as the Clean Charge Network, or the Renewable Solutions Program,
- The specific concerns with allocation and classification decisions described below and in the Rebuttal testimony of Marina Gonzales.

Allocation of production and energy-related cost of service

Q. What are Staff's concerns with EMM's allocation of production and energy-related cost of service, excluding those related to large loads, in the EMM CCOS?

A. EMM allocated to the classes the cost of owning all generation facilities using a four coincident peak average and excess ("A&E-4CP"). EMM allocated the fuel expense and revenues produced by these plants to the classes on the basis of the energy consumed by the classes.

Q. What is the effect of these EMM choices?

A. The effect is that MGS, SGS, and Residential customers pay for 68% of the cost of renewable generation, while LGS and LPS customers are credited with 44% of the value of the energy generated by renewable generation.[25]

Q. Is the A&E-4CP allocator recognized in the 1992 NARUC Cost Allocation Manual ("NARUC manual")?

A. No. The use of a CP demand with an A&E is characterized as a "mistake" in the 1992 NARUC Manual, which includes the following at page 50 concerning the A&E:

> 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.

[25] Small General Service, Medium General Service, Large General Service, and Large Power Service are EMM's non-residential, non-lighting classes.

Q. In his direct testimony at page 26, OPC witness Ronald Nelson recommends use of the Probability of Dispatch ("POD") allocator. What is your response?

A. The POD allocation can be reasonable, but its usefulness and applicability can be limited. For example, the POD approach is not directly applicable when a utility has excess capacity, or when it has plants that do not dispatch in a given test period. The POD allocation assumes that a utility generates to meet exactly its own load, and it can be more appropriate for those circumstances than other allocators such as the A&E. However, like the A&E, it is not a reasonable selection for generation cost responsibility allocation for a utility that participates in a regulated market and its plants dispatch in response to regional price signals.

Q. Have you seen EMM provide O&M expenses by plant to the level of detail that you would use to perform a POD study?

A. I have not. However, much like normalizations would need to be performed to account for plants that do not operate in a given year or as modeled in a party's production cost model, I would expect that a reasonable analyst could devise a method to allocate those expenses among plants and units.

Q. Is the approach of EMM generation allocation in its CCOS consistent with how Brattle Group priced out the cost of service of generation in the non-residential rate study?

A. No. Specifically, at page 16, the Brattle report attached to Graham Jaynes direct testimony states:

> We developed a method to assign demand related costs to the hours of the year that drive those costs, which we refer to as the "delta net load cubed" method. Starting with the hourly net load (gross system load less non-dispatchable renewable generation), we calculated the difference between each hourly net load value and the lowest hourly net load in the year. For each hour i, we calculated a cost allocator by dividing in each hour the cube of the difference by the total sum of the cube of each of hourly difference across the year, as shown in the following formula:
>
> $$\text{Gen Capacity Cost Allocator } i = \frac{(\text{Net Load}_i - \text{Annual Min Net Load})^3}{\sum^{8760}{}_n (\text{Net Load}_n - \text{Annual Min Net Load})^3}$$
>
> The cubic transformation of net load in each hour reflects the fact that the highest load hours incur a disproportionately larger share of system costs. We then aggregated these hourly cost allocators to calculate costs associated with each season and each TOU pricing period of interest.

At page 17 it includes the following:

> Although rates are designed to recover embedded historical costs, defining seasonality and peak periods using forward-looking cost data results in rate designs that send effective price signals and help mitigate future marginal system costs. We assigned costs using the following approach:
>
> • Generation Energy: We assigned generation energy costs to each hour based on the system locational marginal price (LMP).
>
> • Generation Capacity: We assigned generation capacity costs to the top 100 system net load hours of the year based on Evergy Missouri Metro's system load profile. These hours represent periods most likely to drive marginal generation capacity procurement. Under the delta net load cubed approach, a greater share of costs is assigned to the more constrained hours. We used a marginal cost of generation capacity of $298/kW-year based on Evergy's 2028 combined cycle gas turbine costs.

The Brattle treatment is largely consistent with historic Staff recommendations to align responsibility for renewable energy cost of service with the hours in which those assets generated energy. Brattle then netted the demand served by the renewable capacity from the demand relied upon to allocate non-dispatchable costs.

Brattle also allocated energy expense based on hour loads and hourly energy market values. The EMM CCOS did not allocate generation and energy-related cost of service consistent with the Brattle study.

Q. Are there critical shortcomings to the EMM CCOS allocation of generation and energy-related cost of service?

A. Yes. EMM's study does not account for the market value of energy or variations in the market value of energy. Also, in the EMM study, Residential and SGS customers are overallocated the cost of service for generation that provides Renewable Energy Credits required for RES compliance, while LPS and LGS customers are underallocated that responsibility.

Q. Were you able to adjust the EMM CCOS to correct for these issues?

A. I was able to adjust the EMM CCOS to reflect the A&E 4NCP allocator. I was not able to adjust the results to address the inconsistency in the allocation of cost of service and sales revenues, nor for the failure to value RES compliance costs or market energy values. Those results, on a $/kWh basis and on the rate of return provided basis, are provided below:

	Residential	SGS	MGS	LGS	LPS	Lighting	CCN
$/kWh per EMM allocation	$ 0.123	$ 0.087	$ 0.074	$ 0.060	$ 0.051	$ 0.127	$ 0.794
Return per EMM	0.51%	7.92%	8.43%	10.08%	15.63%	3.73%	-39.30%
$/kWh A&E 4NCP	$ 0.121	$ 0.085	$ 0.073	$ 0.061	$ 0.053	$ 0.181	$ 0.849
Return using A&E 4NCP	0.77%	8.60%	8.66%	9.68%	14.10%	-2.42%	-34.81%

Q. Were you able to adjust the EMM CCOS to incorporate an LLPS customer *** [redacted] ***?

A. In general, yes, within the limitations of the EMM CCOS. I modified the production, transmission, and generation allocators to incorporate those LLPS class characteristics. I also increased the energy expense in the study by *** [redacted] *** to acknowledge the value of market energy to serve that load at a conservative amount of $25 per MWh. Finally, I incorporated annualized revenues for the LLPS customer of *** [redacted] *** which is the gross revenue produced by current rates for the described characteristics.

Q. Can you provide the EMM CCOS results as provided by EMM, adjusted to include LLPS, with the 4CP allocator used by EMM and the 4NCP allocator?

A. Yes. Those results are provided below, and in this presentation no LLPS HC information is disclosed:

	Residential	SGS	MGS	LGS	LPS	Lighting	CCN	LLPS
$/kWh per EMM allocation	$ 0.123	$ 0.087	$ 0.074	$ 0.060	$ 0.051	$ 0.127	$ 0.794	
Return per EMM	0.51%	7.92%	8.43%	10.08%	15.63%	3.73%	-39.30%	
$/kWh adding LLPS	$ 0.118	$ 0.083	$ 0.070	$ 0.058	$ 0.049	$ 0.125	$ 0.783	$ 0.054
Return adding LLPS	1.32%	9.26%	10.05%	11.84%	18.20%	4.04%	-40.48%	9.39%
$/kWh A&E 4NCP	$ 0.121	$ 0.085	$ 0.073	$ 0.061	$ 0.053	$ 0.181	$ 0.849	
Return using A&E 4NCP	0.77%	8.60%	8.66%	9.68%	14.10%	-2.42%	-34.81%	
$/kWh A&E 4NCP adding LLPS	$ 0.116	$ 0.082	$ 0.070	$ 0.058	$ 0.050	$ 0.174	$ 0.834	$ 0.053
Return using A&E 4NCP adding LLPS	1.53%	9.88%	10.21%	11.37%	16.53%	-1.84%	-35.91%	10.45%

Q. Do these results mean that the LLPS class is providing a 10.45% rate of return under the current rates?

A. No. What these results illustrate is the difficulty of applying an embedded cost study to competitive load.[26] The cost of service allocated to the LLPS class here includes the benefit of approximately $86 million in deferred taxes that have been prepaid by EMM customers and that are not properly allocable to new competitive load. As discussed above, the current EMM generation fleet cannot provide adequate capacity to serve the amount of LLPS load that EMM anticipates, so new generation will be required. Those generation assets will be more costly than current generation assets, and the overall cost of service will increase. Whether or not other customers are directly harmed by this increase in the cost of service is entirely contingent on whether LLPS revenues consistently increase by more than the cost of service increases.

Allocation of transmission cost of service

Q. Is it reasonable in this case to allocate the transmission-related cost of service using the A&E-4CP allocator?

A. No. Most SPP-related transmission expense is assessed relative to the peak demand in each of the 12 months. The A&E allocator is not a reasonable allocator selection under either a historic view of transmission causation, or the incurrence of market transmission expenses.[27]

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[26] Staff's significant concerns with the EMM CCOS study are also applicable to its allocation of cost of service to LLPS customers.
[27] Mr. Nelson's recommended POD allocation of transmission cost of service is similarly inappropriate.

Q. Have you reallocated the EMM CCOS results to allocate production on a 4 NCP allocator and transmission on a 12 CP allocator?

A. Yes. On the following page are the adjusted results, with and without LLPS. These results are also not reasonable indicators of the cost of service for LLPS customers, or other customers, but do illustrate the impact of the transmission allocator selection. [28]

	Residential	SGS	MGS	LGS	LPS	Lighting	CCN	LLPS
$/kWh per EMM allocation	$ 0.123	$ 0.087	$ 0.074	$ 0.060	$ 0.051	$ 0.127	$ 0.794	
Return per EMM	0.51%	7.92%	8.43%	10.08%	15.63%	3.73%	-39.30%	
$/kWh adding LLPS	$ 0.118	$ 0.083	$ 0.070	$ 0.058	$ 0.049	$ 0.125	$ 0.783	$ 0.054
Return adding LLPS	1.32%	9.26%	10.05%	11.84%	18.20%	4.04%	-40.48%	9.39%
$/kWh A&E 4NCP + 12 CP	$ 0.121	$ 0.085	$ 0.074	$ 0.062	$ 0.053	$ 0.170	$ 0.841	
Return using A&E 4NCP + 12 CP	0.85%	8.52%	8.58%	9.36%	13.82%	-1.43%	-35.30%	
$/kWh A&E 4NCP + 12 CP adding LLPS	$ 0.116	$ 0.082	$ 0.070	$ 0.059	$ 0.050	$ 0.163	$ 0.826	$ 0.054
Return using A&E 4NCP + 12 CP adding LLPS	1.65%	9.86%	10.20%	11.14%	16.36%	-0.87%	-36.45%	9.43%

Distribution cost of service treatment

Q. What aspects of the distribution classification and allocation concerns with the EMM CCOS do you address?

A. I will discuss treatment of PISA cost of service. I will address the reasonableness of EMM's overall approach to distribution classification, and I will respond to EMM's classification of primary voltage circuits as secondary circuits, I will also provide a recommendation for future distribution study improvements.

[28] No HC information is disclosed in this presentation of the information.

PISA Treatment

Q. What cost of service is caused by PISA?

A. There are three categories.

1. The increased rate base associated with new investment,
2. The PISA rate base, which is the sum of deferred capital costs, and is allowed a return as investment,
3. The PISA amortization, which is an expense from ratepayers to shareholders to provide the accumulated PISA ratebase to shareholders.

Q. How should the increased rate base associated with new investment be treated in a CCOS?

A. No special treatment is necessary. The utility should be able to provide a reasonable quantification of the amount of investment in each distribution account that operates at secondary voltage and at primary voltage, known as voltage subfunctionalization. To the extent new infrastructure has been installed, that cost should be included in appropriate voltage subfunctionalization.

Q. Did EMM do that in this case?

A. No. In its voltage subfunctionalization, EMM used historic miles of distribution assets applied to current cost per mile estimates. Based on EMM's capital filings, Staff understands that a majority of the distribution investment incented under PISA is infrastructure that operates at voltages higher than secondary voltage. By inflating all investment to the cost of new investment, then scaling the total back down to reflect embedded cost, EMM is understating the cost of newer investment – which tends to be higher voltage, and overstating the cost of older investment – which includes most assets that operate at secondary voltage.

Q, In general, how should the PISA ratebase and amortization cost of service be treated in a CCOS?

A. PISA cost of service is not related to any customer characteristic such as energy, demand, or customer count. The cost of service associated with PISA ratebase and amortization are caused by Missouri statute and not by the underlying investment. For example, PISA accrued on distribution system assets is not driven by distribution system needs. However, if an analyst were to determine that it is appropriate to recover this cost of service on the basis of distribution investment, there is a less wrong way, and a more wrong way.

Q. What is the less wrong way?

A. The less wrong way would be to associate the PISA cost of service with the underlying asset. For example, if there is a million dollars in PISA amortization expense and return on PISA ratebase resulting from reconductoring a three phase primary voltage power line, then that million dollars should be allocated the same way as a three phase primary voltage power line.

Q. What is the more wrong way?

A. The more wrong way would be to classify a portion of the distribution system as customer related, subfunctionalize a portion of the distribution system as the responsibility of customers served at secondary voltage, subfunctionalize the remainder of the distribution system as the responsibility of customers served at primary voltage, and then allocate the PISA amortization expense and return on PISA ratebase to all three pieces. This approach shifts responsibility for the state's PISA policy disproportionately to customers served at lower voltages. While all customers pay towards the three-phase primary voltage portions of the distribution system, only customers served at secondary voltage pay towards assets that operate at secondary voltage, and smaller customers as a whole are allocated more responsibility for the customer-classified portion of distribution accounts than is allocated to larger customers as a whole.

Q. Have you been able to ascertain how EMM allocated the cost of service of PISA amortization expense and the return on PISA ratebase in its CCOS study?

A. Not entirely, but it appears EMM allocated these costs of service consistent with the "more wrong way."

EMM's Distribution Approach

Q. How did EMM classify, subfunctionalize, and allocate its distribution system cost of service in its CCOS study?

A. EMM first classified a customer-related portion of each account.

Q. Is the manner in which EMM applies the customer-related classification of the distribution accounts consistent with the NARUC Manual?

A. No. EMM's approach does not rely on the infrastructure that would serve the minimum load of a typical Residential or SGS customer; instead, it considers a "minimum" system that operates at primary voltage. It also improperly includes switches and other devices. Further, as addressed by Marina Gonzales, it relies on unreasonable count information, and improperly adjusts the rate base associated with infrastructure by a pricing index.

Q. How does the NARUC Manual address the sizing of the assets selected for the minimum infrastructure?

A. At pages 90-91, the NARUC Manual instructs:

> Classifying distribution plant with the minimum-size method **assumes that a minimum size distribution can be built to serve the minimum loading requirements of the customer.** The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility.[29] Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). **[Emphasis added.]**

Q. Can you provide examples?

A. Yes. EMM used a 35' wood pole as its minimum system asset.

Q. Does EMM have poles that are less than 35' tall in use?

[29] Discussion of a marginal cost study at page 138 of the NARUC Manual provides further context for these issues:

> The minimum grid approach re-designs the distribution system to determine the cost in current year dollars of a **hypothetical system that would serve all customers with voltage but not power (or with minimum demand of 0.5 KW)**, yet still satisfy the minimum standards for pole height and efficient conductor and transformer size. The calculations can be based either on the system as a whole or on a sample of areas reflecting different geographical, service and customer density characteristics.
>
> When applying this approach, it is necessary to **take care that the minimum size equipment being analyzed is, in fact, the minimum-sized equipment available, and not merely the minimum size stocked by the company or usually installed by the company. To the degree that the equipment being costed is larger than a true minimum, the minimum grid calculation will include costs more properly allocated to demand. [Emphasis added.]**

A. Yes. Of EMM's 155,682 Missouri poles, 33,147 are listed by EMM as 30' or shorter. The Continuing Property Record average cost of these shorter poles is $359, in contrast to the Continuing Property Record average cost of $780 for the 35' wood pole.[30]

Q. How does EMM classify the overhead conductor account?

A. EMM classifies 53.62% of the overhead conductor account as customer-related, premised upon every customer contributing equally to the need for all conductor to be at least a primary conductor "Conductor Bare-ACSR-#2 ACSR (6/1)", and including two primary switches, two heavy duty arresters, and the labor to install these and other items atop a 40' pole. EMM's response to Staff data request 340 indicates that the minimum conductor selected for the Overhead analysis is used in their system exclusively for Primary voltage circuits.

Q. What is the issue related to the treatment of devices?

A. Pages 90-91 of the NARUC Manual states, "[o]nce determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs." Significant context can be established from the discussion of applications of the minimum-intercept method, at pages 93-94, "[w]hen developing the customer component, consider only the investment in conductors, and not in devices such as circuit breakers, insulators, switches, etc.

[30] As discussed by Marina Gonzales, EMM scaled up all book values for infrastructure using the Handy Whitman index.

The investment in these devices will be assigned later between the customer and demand component, based on the conductor assignment."

EMM included millions of dollars of lightening arrestors and switches in its customer component calculations, meaning that a residential customer in an apartment and a 74 MW data center should pay the exact same amount for these components.[31] Based on prior discussions with EMM distribution personnel, while many of those switches are used to direct power flows on the distribution network, many of those switches are actually customer-specific infrastructure associated with the ability to turn power off to a particular large customer.

Q. EMM finds the geographic size of the distribution system and calculates the cost to build and operate all of the miles of that system at primary voltage. Does it take this into account when allocating the remaining distribution cost of service?

A. No. Although EMM used assets that operate at primary voltage for its minimum system calculation, it did not follow the instruction at page 95 of the NARUC Manual to recognize that the system used in the minimum system study has load-carrying capability.

> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. **When using this distribution method, the analyst must be aware that the minimum size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.**

[31] Customers served at transmission voltage are excluded from any cost responsibility for the distribution system.

> When allocating distribution costs determined by the minimum-size method, some cost analysis will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those **customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs**.
>
> **[Emphasis added.]**

Q. Is EMM's distribution approach otherwise consistent with the NARUC Manual?

A. No. EMM has not relied on embedded cost for subfunctionalization of the distribution system and application of the MECG-requested shift in responsibility for single phase primary distribution assets.[32]

Pages 90-91 of the NARUC Manual state, "Normally, the average book cost for each piece of equipment determines the price of all installed units." EMM instead uses costs that it has adjusted.[33] While in some cases such an adjustment may have a negligible effect, in this case EMM has significant additions of primary voltage infrastructure, which were incented by PISA policy.

To avoid allocating cost of lower-voltage distribution infrastructure to customers who are served at higher voltages, it is necessary to subfunctionalize the cost of the distribution system by voltage. As discussed below, EMM chose to perform that subfunctionalization in a way which is suboptimal and that distorts the expected

[32] See Graham Jaynes direct testimony, page 43, lines 15 – 17.
[33] EMM's use of the Handy Whitman index to adjust the cost of minimum system components is discussed in the Rebuttal testimony of Marina Gonzales.

relationship between the actual investment EMM has made in infrastructure that operates at primary voltage and infrastructure that operates at secondary voltage.

Simply, about one third of EMM's system operates at secondary voltage, and most of it is old, while about two thirds of EMM's system operates at primary voltage, and some of it is new. EMM's distribution subfunctionalization looked at the number of miles at each voltage category, and the cost per mile of building it new. This exaggerates the amount of investment that EMM has made in secondary-voltage infrastructure, and shifts cost responsibility for the distribution system as a whole to classes made up of customers served at secondary voltage.[34] It also understates the contribution required from classes made up of customers served at higher voltages for distribution system upgrades encouraged by PISA policy.

Subfunctionalization and Single Phase Primary Treatment

Q. EMM's classification of the distribution system establishes how much of an account will be allocated on the basis of the number of customers in each class. How does EMM allocate the remainder of the distribution accounts that it does not allocate to the classes based on the number of customers in each class?

A. EMM subfunctionalizes the remainder of the distribution accounts by voltage.

Q. Is this reasonable?

[34] This issue is exacerbated in the approach EMM took to subfunctionalization in its CCOS study, as discussed above.

A. Yes, and no. It is reasonable to subfunctionalize an account by voltage, but EMM's calculation and application of the subfunctionalization is not reasonable.

Q. Focusing first on overhead conductors, what did EMM do?

A. EMM first lists all known distribution circuits by type ("overhead" and "underground"), voltage ("distribution," in this case, referring to primary voltage, and "secondary,") and phase ("3" and "1"). For each, EMM provides the feet recorded in its GIS system, which it converts to miles by dividing by 5,820. This table is attached as schedule SLKL-r4.

EMM then uses "line cost estimates," [35] based on a single selected conductor type for each permutation of account, voltage, and phase.

Finally, EMM sums its calculation of single phase primary costs with its calculation of secondary costs for allocation to only secondary customers.

Q. Why is this approach not reasonable?

A. EMM should rely on the embedded cost reflected in rate base for the cost of the three phase primary distribution assets, the single phase primary distribution assets, and the secondary voltage distribution assets. Staff acknowledges that the historic EMM records are unreliable due to the manner in which retirements have been

[35] EMM's supplemental response to Staff DR 316, attached as schedule SLKL-r 6, (attachment omitted) states ** [redacted] ** Staff's review of the confidential attachment to the supplemental response indicates that poles are included in the line cost estimates that EMM relies upon for the overhead conductors account, although poles are not recorded to the overhead conductors account. EMM's initial response to DR 316 is attached as schedule SLKL-r7.

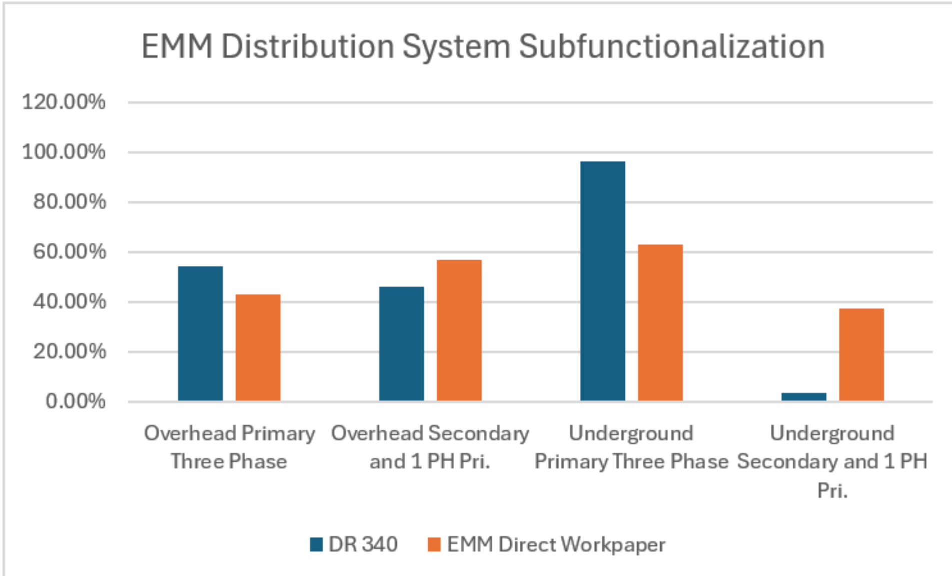
recorded. Going forward, a relationship between embedded cost and current cost should be established; EMM did not even make the best use of the information available to it at this time.

Q. What available information did EMM not use?

A. In response to DR 340, EMM provided what it represents to be the representative cost for each and every circuit relied on in its subfunctionalization calculation. The cost per voltage is attached as schedule SLKL-r5, A comparison of the results of EMM's subfunctionalization calculation to its actual subfunctionalized total costs, provided in response to DR 340, indicates the effect of EMM's approach shifts cost responsibility away from customers served at voltages higher than secondary voltage. The table below provides the percentages of the overhead conductors account, and the percentages of the underground conductors account associated with each voltage level:

	DR 340	EMM Direct Workpaper
Overhead Primary Three Phase	54.19%	43.18%
Overhead Primary Single Phase	4.55%	19.38%
Overhead Secondary	41.26%	37.44%
Underground Primary Three Phase	96.44%	62.73%
Underground Primary Single Phase	1.13%	14.70%
Underground Secondary	2.43%	22.57%

This shift in cost responsibility becomes more apparent in EMM's next step – in which EMM shifts responsibility for the Primary Single Phase system entirely to secondary customers.



Q. What is the result of EMM's decisions to inappropriately include devices in the customer classification, to choose primary-voltage infrastructure to calculate the customer classification, and to ignore the demand-serving capability of its calculated minimum system?

A. The result is an unreasonable shift of cost responsibility to customers who are served at secondary voltage, and away from customers served at higher voltages, making the EMM CCOS unreliable for allocating cost of service responsibility in this case.[36] It is also renders the conclusions drawn from the EMM CCOS wholly unreliable for establishing the relationship between the facilities charges in EMM's restructured rates.

[36] Staff data request 341 attempted to obtain the cost of conductor to serve representative minimal load of 25 kW at 120/240 volts. EMM was unable to provide that information on the basis that, "Projects involving 120/240-volt customers span a wide range of scopes and configurations, from very small installations serving a single customer to large-scale distribution extensions serving numerous customers simultaneously." EMM's response is attached as SLKL r 8.

Q. Can you summarize the problem distribution classification and subfunctionalization try to solve, in non-technical terms?

A. I can try. EMM has assets that are only used to serve customers served at secondary voltage. Those customers should pay for those assets. Customers who are served at higher voltages should not pay for those lower voltage assets. All customers should pay fairly for the use of assets that operate at higher voltage and serve all customers. None of this is in dispute. The problem is that EMM doesn't adequately attribute cost responsibility to the three-phase primary system which is paid for by everyone based on how much demand they cause, and EMM over-attributes costs to its customer classification, which is paid for by every customer equally.

	DR 340	EMM Direct Workpaper	EMM Direct CCOS
Overhead Primary Three Phase	54.19%	43.18%	13.31%
Overhead Secondary and 1 PH Pri.	45.81%	56.82%	33.08%
Overhead Customer-Classified			53.62%

Q. Were you able to adjust the EMM CCOS results to account for these distribution issues and those addressed by Marina Gonzales?

A. No.

Moving Forward

Q. Do you have an additional suggestion for EMM to consider in its future CCOS studies?

A. Yes. In response to Staff DR 291,[37] EMM states:

> Secondary voltage lines are not interconnected directly with higher voltage lines. In most cases, higher voltage lines are connected to

[37] Attached as SLKL-r9.

> the "input" side of a transformer, and the secondary voltage lines are connected to the "output" side of the transformer. Based on a recent count from the mapping system, there are 42,564 overhead transformers and 19,077 underground transformers identified in the Missouri Metro jurisdiction. Note, counts for field installed units will not follow accounting for the transformers in our plant records.

EMM serves 308,988 customers at secondary voltages. However, many of those 308,988 customers are served via circuits operating at secondary voltage. According to EMM, EMM operates around 6,800 miles of distribution system at secondary voltage, and it operates around 20,000 total miles of distribution system.[38] The number of customers served at secondary voltage cannot drive the number or placement of higher-voltage assets, the number and placement of higher-voltage assets can only be driven by the number of step-down transformers. In future CCOS studies, for the customer-classification of primary voltage assets, EMM should use the sum of the number of transformers interconnected to primary distribution system and the number of customers served at primary voltage, not the total customer count. The number of customers interconnected at lower voltage through a transformer cannot drive the customer-classified investment in higher-voltage assets.[39]

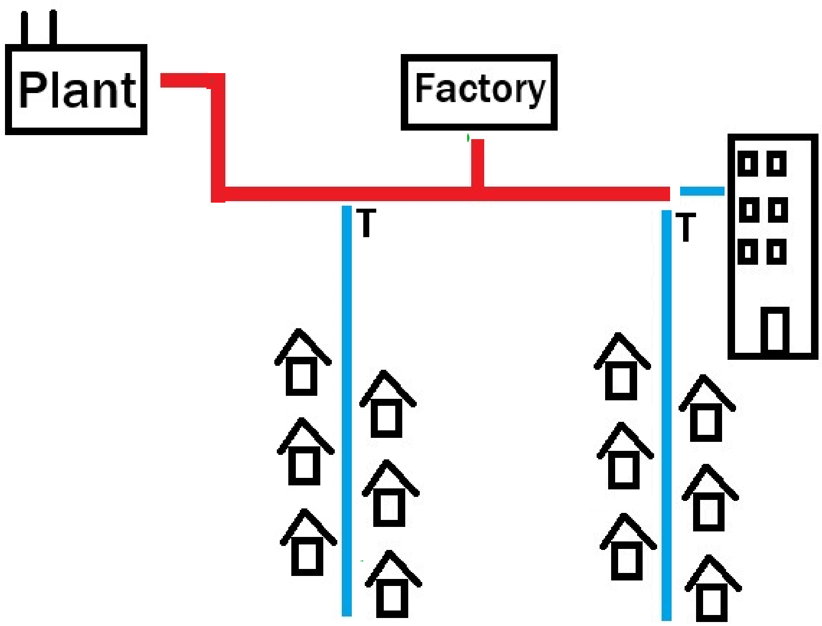
Q. Can you provide an illustration of this issue?

---

[38] There are inconsistencies among the miles identified within EMM's workpapers. It is not clear exactly how many miles of circuits EMM operates. Mr. Jaynes workpaper, "CONFIDENTIAL Support Paper Conductor Min System Analysis," tab "PRI-SEC," indicates 20,883, however the values Mr. Jaynes uses on tab "Min_Sys_Cond" of the same workpaper total to 18,919. It is unclear whether either total includes subtransmission/HV conductors.

[39] EMM should also recognize the demand-carrying capability of its minimum system assets, and not include non-conductor items in its minimum-system calculation, as well as improve its alignment of voltage subfunctionalization with historic costs.

A. Yes. Consider a simple utility with one power plant, serving one factory and two residential subdivisions (each with six houses), and an apartment complex (with 6 units). The red lines in the illustration below represent distribution lines operating at primary voltage. The blue lines represent distribution lines operating at secondary voltage.



Staff does not dispute that the blue lines should be allocated to the customers in the houses and the apartment. Staff does not dispute that the factory should not pay for the blue lines. However, the fair customer classification of the red line would consider three interconnections (two transformers and the factory), not 19 customers (1 factory, 12 houses, and 6 tenants).[40]

[40] The portion of the red line that runs from the main system to the factory should be allocated to the factory, and should not be included in a minimum system study.

Q. Staff has raised issues with the distribution classification and subfunctionalization in several EMM and Evergy Missouri West ("EMW") rate cases. Is the situation improving?

A. Staff is hopeful that upon completion of the rate restructuring and resulting customer migrations, and prior to EMM's next rate case, consensus can be reached, at a minimum, on the cost of infrastructure in each account that operates at secondary voltage, primary voltage, and substation voltages. Staff is not opposed to delineation of the primary system between three phase and single phase, so long as the delineation is reasonably made. With EMM's improvements to its GIS system, Staff is cautiously optimistic that these calculations will be better facilitated. Improved transparency is needed into the current cost per mile calculations that EMM relies on. Because EMM's rates are based on embedded cost, a reasonable relationship between EMM's current cost calculations and the actual distribution rate base must be relied upon. The demand-carrying capabilities of a selected minimum system must be acknowledged.

Administrative and Other

Q. In its CCOS study, how did EMM allocate the cost of service for the residential battery program?

A. EMM allocated the cost of service for the residential battery program to the residential class.

Q. Is that reasonable?

A. No. The tariff for the program includes the following:

> The Residential Battery Energy Storage (RBES) pilot will evaluate the ability of residential batteries to deliver customer benefits and provide services in support of the Company's electrical system. The RBES pilot will allow the Company to evaluate the ability of a residential battery energy storage system (BESS) to 1) provide the Company with demand response capacity to better manage grid and system peaks charging, 2) minimize grid impacts by self-consuming renewable generation and minimizing exports to the grid, and 3) provide customer bill savings and back-up power benefits.

And,

> Company may operate the BESS for a variety of uses, including but not limited to:
>
> 1. Customer self-consumption local generation to minimize the export of energy and minimize the customer energy draw from the grid during peak usage periods.
>
> 2. Charge the BESS from local generation or the Company's power grid when energy costs less, during "off-peak" hours.
>
> 3. Use the reserved/stored capacity of the BESS to manage system load during periods of peak usage.

The pilot was supposed to use residential customers to study the feasibility of using distributed battery systems to address generation and transmission needs and to moderate energy market expense. For residential customers who were not participants, there was no more and no less benefit to the program than for an LPS customer. This cost should not be born exclusively by residential customers.

Q. EMM allocated generation cost of service on the basis of demand and energy allocators, transmission cost of service on the basis of the A&E 4CP allocator, distribution costs of service on the basis of customer counts and demand allocators, and metering and billing costs of service on the basis of customer-based allocators. How did EMM allocate everything else, such as general plant, software, regulatory expenses, PISA, and other recoverable cost of service that isn't related to customer demand, energy consumption, or number of customers served?

A. EMM functionalized all of these other costs to the generation, transmission, distribution, billing and metering functions using internal allocators. This means that EMM's calculated residential customer charge includes amounts for EMM's recoverable legislative activities, its employee break room, and other elements of cost of service which are included in revenue requirement, but do not vary with the addition of a residential customer.

CLASS REVENUE RESPONSIBILITY AND RATE DESIGN

Q. Does Staff agree with the CCOS conclusions and revenue responsibility recommendations recommended by the parties?

A. No. As discussed above and in the testimony of Marina Gonzales, EMM's study relies on a problematic approach to production allocations of allocating the cost to own and operate power plants differently than the revenue received from operating those plants, relies on an inappropriate transmission allocator, relies on problematic distribution classification, subfunctionalization, and perpetuates those errors through its internal allocation of other cost of service that are not related to production, transmission, or distribution.

Q. Is this simply a question of allocator selection?

A. No. For example, with regard to production allocation, Staff is of the opinion that for a utility operating in an integrated energy market in the State of Missouri with RES requirements, such as EMM, reasonable allocation of production and energy cost of service requires consideration of the generation fleet being allocated and consideration of how the needs of each class for Renewable Energy Credits produced by that fleet relate to RES requirements. That is a difference of opinion with EMM. However, for calculation of an Average and Excess allocator, the decision of EMM to use coincident rather than non-coincident peaks is not consistent with the NARUC instructions for what peaks are appropriate for use in an A&E allocator. Similarly, EMM's decision to rely on a minimum system study versus Staff's preference for a zero-intercept study for the classification of customer-related costs is an opinion. However, EMM's use of primary-sized infrastructure and failure to account for demands already allocated is not consistent with the NARUC instructions for distribution classification. All in all, Staff cannot recommend the Commission rely on the EMM CCOS for revenue allocation or rate design purposes in this case.

Q. Are there other issues unique to this case that should be considered in determining revenue responsibility allocations in this case?

A. Yes. First, the studies do not and cannot reasonably consider the impact of the additions of large loads, including significant changes that have occurred to the LPS class demand and energy requirements that are not reflected in the CCOS studies. Also, EMM proposes, and Staff recommends, rate restructuring and implementation of "bright lines" in this case, which will result in customer migrations. EMM's approach to developing the classes for its "proposed" studies was inadequate and improper, and its studies for its "current" classes are inapplicable to the expected outcome of this case.

Q. EMM recommends an equal percentage increase to class revenue responsibilities. Is this consistent with Staff's recommendation?

A. Staff is aware of one distinction. EMM appears to include in its current class revenue calculations revenue from rates that are not generally subject to change in a general rate case. The easiest example of this is the solar block rate, which was set when a given solar facility was made available for subscription and will not change until the subscription program ends. If that revenue is included in class revenue when a percentage increase is applied, then all other rates will have to be increased extra to make up for not increasing the revenue from a rate which should not have been included in the calculation to begin with.

Q. What is Staff's response to the CCOS study and revenue responsibility recommendation of OPC's witness Ron Nelson?

A. Mr. Nelson indicates that he was unable to provide completed study results or a revenue responsibility recommendation at the time of filing his direct testimony. Because Staff's overall recommendation is to reject recommended revenue responsibility shifts, and Mr. Nelson did not directly address this subject, I have not devoted the significant time that would be required to either support or oppose Mr. Nelson's POD allocator calculation for use as a production allocator. I disagree with Mr. Nelson that the POD allocator is appropriate for transmission under the circumstances of the EMM system and EMM's status as a transmission owner and customer of integrated transmission systems under the functional control of SPP.

Q. What is Staff's response on these issues to MECG Witness Jessica York?

A. Ms. York's mild modifications to the EMM study retain the problematic approach to production allocations of allocating the cost to own and operate power plants differently than the revenue received from operating those plants, and retain the problematic distribution classification, subfunctionalization, and allocation issues of the EMM study. For clarity, not only does Ms. York rely on EMM's functionalization, classifications, subfunctionalizations, and allocations except for her change to some of the coincident peaks used in the A&E 4 CP production and transmission allocators which are inconsistent with the NARUC Manual, but Ms. York also relies on EMM's revenue requirement calculation, which includes the CWIP recovery requested by EMM.

Q. Does Ms. York's Table 5 provide a view of class revenue responsibility that is based on Staff's revenue requirement quantification?

A. It does not. When a CCOS study looks at the rate of return provided by a given class, that is assuming a level of rate base allocated to each class. An analyst can't simply apply a percentage adjustment to the class's shares of a total revenue amount to revise a CCOS study from one revenue requirement calculation to another, as Ms. York does in her table 5. To further clarify, Ms. York's Table 5 provides her proposed increases for what she characterizes as a Staff-recommended $85 million increase, when in fact, Staff's direct-recommended increase was $33.46 million.

Q. Is Staff generally supportive of moving to 15 minute on-peak demand for the billing determinant applicable to non-residential customers?

A. Yes.

Q. Does Staff object to the "bright lines" demarcations for class minimum demands selected by EMM?

A. No.

Q. What are Staff's concerns with EMM's restructured rate tariffs?

A. While Staff generally supports EMM's restructured rate tariffs,[41] Staff's specific concerns are:

(1) Inadequacy of current information available to calculate restructured rates that will recover the Commission-authorized cost of service, (discussed by Marina Gonzales)

(2) Inadequacy of communications to customers, and reasonableness of implementation plan,

(3) Refinement of time periods selected,

(4) Refinement of rate designs,

(5) Refinement of facilities charges,

(6) Inappropriate removal of reactive demand charges.

Customer Communications and Implementation Plan

Q. Have you reviewed EMM's planned customer communication or education plans?

A. I have not. To my understanding they do not exist at this time, in any form.

Q. Has Staff asked EMM about its plans to inform customers of the changes to how they will be billed?

[41] Staff does not support EMM's proposed changes to the standby rate tariffs, and recommends that the tariffs be aligned with restructured rates.

A. Yes. Staff requested information from EMM related to its plans for customer education and billing system preparedness.

Staff Data Request 0238 requested that EMM:

> Please fully explain Evergy Missouri Metro's customer education plan including timelines for informing customers of its proposed rate restructuring, any rate restructuring ordered by the Commission, initial customer migration to restructured rates, and any short term re-migrations based on changes in customer characteristics or improper initial migration.

EMM's March 30, 2026, response was:

> Evergy does not normally prepare customer education plans as part of proposals made in its direct testimony. Historically, it has been common for intervenors in the general rate proceeding to disagree with all or part of a Company proposal. As a result, Company proposed rate changes can be changed dramatically during the course of the general rate proceeding. Efforts spent preparing detailed customer education plans would be imprudent. Instead, as the general rate proceeding progresses, if the Company believes a rate proposal is being found acceptable, more detailed planning, including the creation of customer education plans may occur. At its most extreme, should a proposal go to hearing and remain uncertain until the Final Order, detailed implementation planning will also wait.
>
> With respect to the proposals made in this case, the Company is prepared to establish detailed customer education plans when it judges the timing is right to expend this effort. Based on prior rate implementations it is reasonable to expect the customer education plans will include the following elements,
>
> - Identification of customers affected by the approved rate design proposals
> - Detailed talking points concerning the purpose, operation, and effect of the approved rate design proposals
> - Educational materials (web-based, electronic or hard copy)
> - Planned channels for communication

- Training of Company-representatives and Customer Support personnel

EMM has not updated or supplemented this response.

Q. Have representatives of impacted customers expressed concern with EMM's restructuring plan?

A. Yes. Jessica York, on behalf of MECG, testifies at page 19 that, "I recommend that the Commission either defer this structural change or, if it elects to move forward, direct the Company to implement it through a phased transition with appropriate mitigation. My recommendation is not based on disagreement with the direction of the proposed structure. It is based on the absence of information necessary to determine whether the proposed change produces just and reasonable results for individual LGS and LPS customers."

Ms. York's concerns are in line with the recommendation Staff provided in the Rate Design Report at pages 27 – 28:

> Staff recommends that EMM inform its non-residential customers of the restructured rates and provide reasonable education to those customers. This should include a statement of the rate schedule the customer has been billed on, the rate schedule the customer will be billed on, simple and clear education concerning the time-based periods ordered in this case, an explanation of the recommended delay in restructuring until November 2027, and a one-time report of the following:
>
> 1. A statement of the total energy and 30-minute demand for 12 historic billing months,
> 2. A statement of the total energy, energy by time-based period, 15-minute NCP demand, and 15 minute on-peak demand for the same 12 historic billing months,
> 3. A calculation of the bill the customer would owe for the usage and demand for those 12 historic months on the increased non-restructured rates that are ordered in this case, and

4. A calculation of the bill the customer would owe for the usage and demand for those 12 historic months on the restructured rates that are ordered in this case and effectuate the rate increase.

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

Refinement of time periods selected

Q. Has Staff observed and has EMM demonstrated that there is a reasonable basis for excluding weekends and holidays from peaks?

A. No. Staff has observed peak conditions on weekends and holidays for various utilities in various years.

Q. Have you compared EMM's requested non-summer demand periods to historic EMM system peaks?

A. Yes. Staff reviewed the months and hours of historic EMM peaks relied upon by SPP. The number of instances of peaks in each hour, by season, are set out on the following page:

(continued)

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

It is readily observed that 7:00 am and 8:00 am are frequently peak-setting hours in non-summer months. EMM requests that winter demand be measured between the hours of 9:00 am and 9:00 pm, which would not include the hours in which the most monthly peaks have occurred in the winter billing months.

Q. Are there other, less critical issues to be addressed with EMM's time period selections?

A. Yes. The following compares the EMM requested periods and the Staff-recommended periods for each billing season with the instances of peak hours, and the relative loads and energy prices:

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
EMM Demand Period	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0
Staff 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
# of times Peak Hour Occurs																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%
EMM Energy Price Period	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	2	2	2	2	1	1	1	1	1
Staff 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

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
EMM Demand Period	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
Staff 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
Non Summer Peak Hours								11	3	1	1					1	6	4	4	0	1			
Winter Peak Hours								9	1	1	1					0	0	1	3	0	0			
Non Summer Load	84%	82%	81%	80%	80%	81%	83%	87%	89%	90%	90%	91%	90%	91%	91%	91%	91%	92%	93%	94%	93%	92%	90%	87%
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	93%	92%	91%	91%	91%	92%	94%	98%	100%	100%	99%	98%	95%	97%	96%	96%	96%	96%	98%	99%	99%	98%	97%	95%
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%
EMM Energy Price 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
Staff 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

0	off peak or exclude
1	on peak
2	highest rate

For summer billing months, EMM ends what it terms, “super off peak,” at 6:00 am, and this period continues until 3:00 pm. However, the 1:00 – 2:00 hours are heavily loaded and experience high prices. Staff is concerned that with the long lapse of time from the end of the super-off peak period to the 3:00 pm on peak period, that customers will not be able to realistically shift load from after 3:00 pm to before 6:00 am. While customers may seek to avoid on-peak pricing, the customer’s outcome is financially the same whether they shift load that would otherwise occur during the 3:00 pm hour to either the 2:00 pm hour or the 6:00 pm hour. Staff recommends extending the very low-priced overnight period as far into the midday as is reasonable to facilitate load shifting from after 3:00 pm to earlier in the day, and to mitigate the likelihood of creation of a new 2:00 pm peak hour.

Also during summer billing months, the 7:00 pm and 8:00 pm hours have high loading. Staff is concerned that EMM’s decision to end the peak pricing time at 6:00 pm would result in a rebound that will create new peaks in those hours, which are already relatively high cost from an energy pricing perspective. Similarly, the very short demand period selected for summer months is easily avoided entirely by some customers, and doing so is likely to drive additional peaks immediately prior to and immediately after the selected period, in hours with already high energy prices and high levels of system loading.

Finally, EMM’s energy prices do not address the distinct dual peaks which occur during non-summer months. Staff recommends some recognition of those peaks in the energy rate design.

Refinement of rate designs

Q. Does selection of the energy and demand periods influence the appropriate rate designs?

A. Yes. The on peak / off peak price differential should be sized to correspond to the wholesale energy price differentials for those periods. The demand rates will depend entirely on the amount of determinants that result from the peak periods selected.

Q. Does Staff have concerns with EMM's energy rate selections setting aside the time periods?

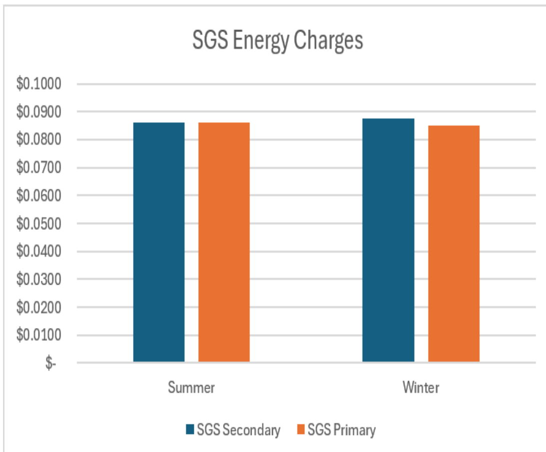
A. Yes. It appears that when calculating its rates, EMM attempted to retain revenue neutrality at the level of customers served within a class. This results in an illogical and unreasonable relationship of rates to each other, and does not actually mitigate customer impacts. In fact, by using smaller and smaller subsets of customers for establishing revenue neutrality, it likely exacerbates the realization of the bill impact of the restructuring on individual customers, by reducing the number of determinants over which required revenue is collected.

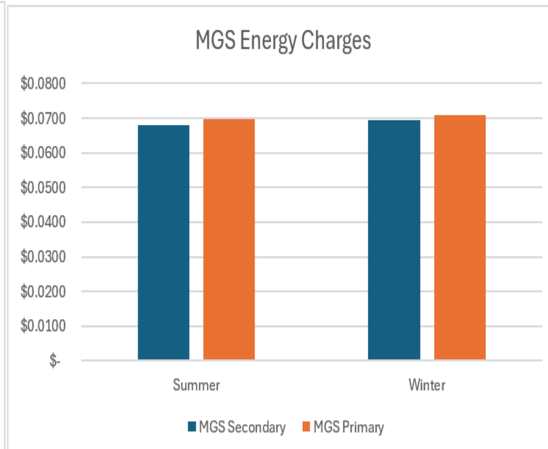
Q. What do you mean in simple terms?

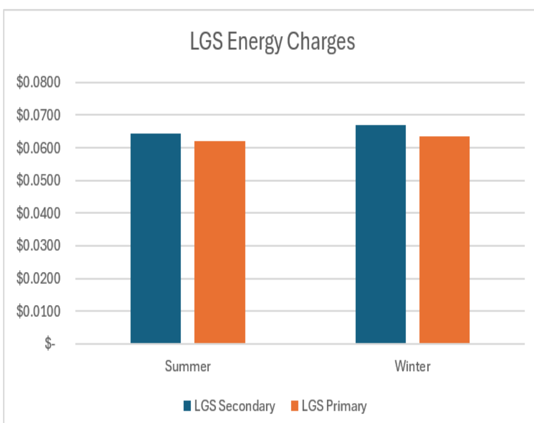
A. In simple terms, it doesn't make sense that in MGS the energy rate for customers served at primary voltage is higher than the energy rate for customers served at secondary voltage, and in LGS the energy rate for customers served at primary voltage is lower than the energy rate for customers served at secondary voltage, and for LPS the rates are inconsistent as to whether increases in service voltage increase or decrease the requested rates.[42]

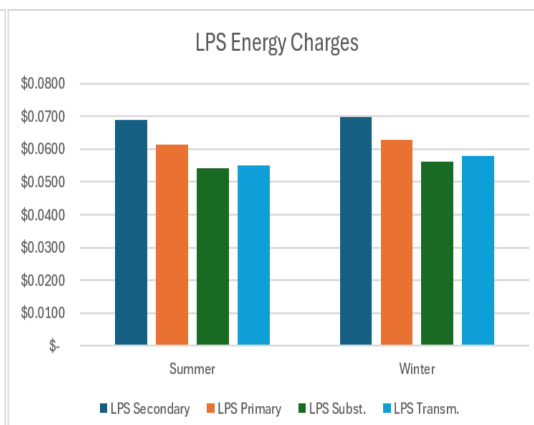
Q. Can you set out the relationship of energy rates EMM requests in its tariff, including its requested increase?

A. Yes.





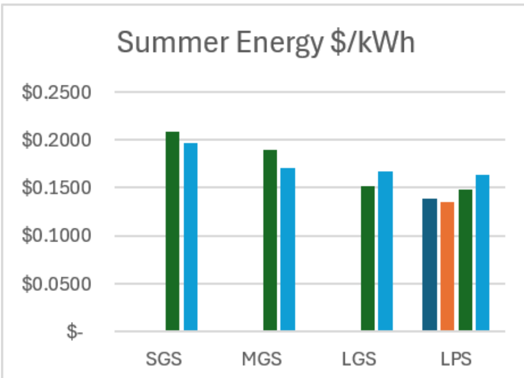


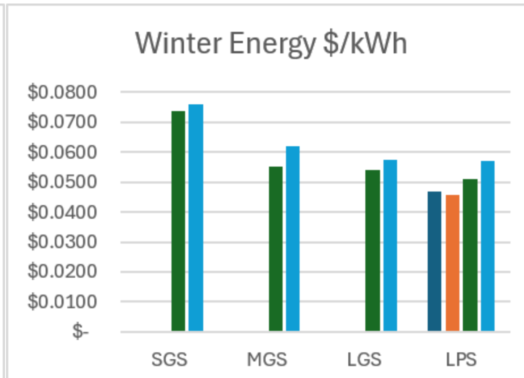


Q. Can you set out the relationship of energy rates EMM used in its revenue neutral calculations, prior to application of its requested increase?

[42] It appears these inconsistencies are the results of calculating rates including the peak adjustment rates, at a proposed class voltage level, as opposed to at a class level.

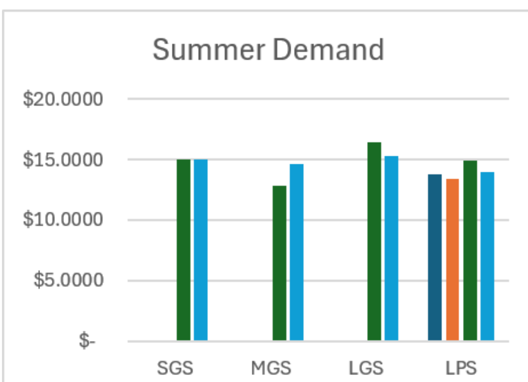
A. Yes. In the following charts, the bright blue columns provide the rates applicable to customers served at secondary voltage, the green columns provide the rates for customers served at primary voltage, the orange columns provide the rates for customers served at substation voltages, and the dark blue columns provide the rates for customers served at transmission voltages.

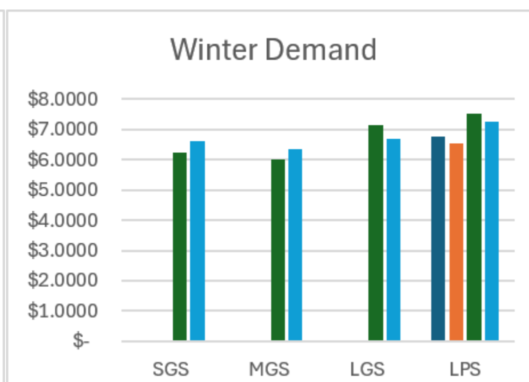




Q. Do similar unreasonable relationships exist in EMM's demand charge designs?

A. Yes. The relationship of demand rates EMM used in its revenue neutral calculations, prior to application of its requested increase are provided below:





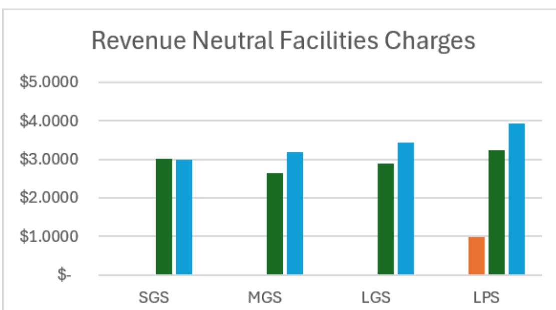
Refinement of facilities charges

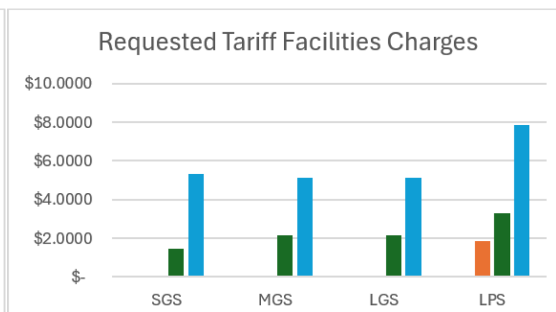
Q. Are EMM's requested facilities charges reasonable?

A. No. The EMM facilities charges are largely outgrowth of EMM's unreasonable distribution classification, subfunctionalization, and allocations.

Q. Are the requested charges constant across classes?

A. No. In the Unanimous Stipulation and Agreement in ER-2024-0189, Evergy Missouri West committed that, "In the next EMW rate case, the Company will take additional steps to align facilities charges across classes, and will maintain consistent customer charge pricing within each class." This refers to a goal that a facilities charge for service at primary voltage be the same charge per kW, whether a customer is served in LPS, LGS, MGS, or SGS. Staff agrees with this goal, and implementation of this goal is consistent with EMM's stated interest in establishing consistency in rate structures and designs across its jurisdictions.





Reactive demand charges

Q. What justification did EMM provide for removing reactive demand charges from all non-LLPS classes?

A. None.

Q. Is this consistent with Staff's recent recommendations?

A. No. Given the increasing needs for investments to address reactive demand requirements due to changes in the regional generation fleet, Staff has recommended improved retention of customer reactive demand requirements for potential refinement or additions of reactive demand charge recovery.[43]

Time Related Pricing Tariff and Opt-In Time of Use Rate Schedules

Q. Does Staff recommend the Commission approve the non-residential opt-in Time of Use ("TOU") rates requested by EMM?

A. No. Staff does not support highly differentiated opt-in rates that allow customers to avoid revenue responsibility for reasonably allocated costs of service. Similar to Staff's concerns with the restructured rates, Staff also opposes the manner in which EMM has modified the relative pricing elements of the Brattle-recommended rates.

Q. Does Staff support the Time Related Pricing ("TRP") Tariff elimination recommended by EMM?

A. Staff has concerns with the pricing and design of the TRP tariff. However, a well-designed TRP tariff could meet the customer desires that underlie optional highly-differentiated opt-in TOU tariffs.

Q. What is Staff's recommendation for the continuation of the TRP rate schedule and development of opt in TOU-rate schedules?

A. Staff recommends freezing the current TRP schedule to new customers and new premises. Staff recommends interested parties work together to develop a replacement rate plan under which customers opt-in to billing at the price of

[43] EMM confirmed in its response to Staff data request 243, attached as schedule SLKL r10, that Staff has not encouraged the removal of reactive demand charges.

the EMM DA-LMP, and pay reasonable demand and other charges to reflect the other costs of service incurred for these customers.

INCOME ELIGIBLE RATE

Q. In his Rate Design Direct testimony at page 52, Dr. Marke stated that it was his understanding that Staff would be recommending a volumetric rate to address affordability. Did Staff recommend a volumetric rate?

A. No. I confirmed with Dr. Marke that this was related to a miscommunication resulting from an interrupted discussion between myself and Dr. Marke on another topic.

Q. Regarding Dr. Marke's recommendation to waive the customer charge for qualifying customers, what is Staff's response?

A. Staff expert Tammy Huber provides Staff's position regarding program design. She notes that EMM had approximately 12,000 customers who were LIHEAP recipients in the year 2025.[44] Below, I will provide Staff's recommendations concerning avoided revenue treatment and allocation.

Q. If the Commission waives the residential customer charge for 12,000 residential customers, what amount of revenue would not be collected from those customers that would otherwise be collected?

A. The Staff has recommended retaining the current residential customer charge of $12.00 per month, while EMM recommends the customer charge be increased by the residential average percent increase. If the customer charge is waived

[44] EMM has approximately 276,000 residential customers.

for 12,000 customers, the annual revenue not recovered from those customer charges is roughly $1.44 million at Staff's recommended customer charge level, and approximately $1.66 million at the EMM requested customer charge level.

Q. Is it Staff's recommendation that if Dr. Marke's recommended customer charge waiver is approved by the Commission that EMM would bear financial responsibility?

A. No. Staff recommends that if a customer charge waiver is approved and the revenue shortfall associated with that waiver is approved to be recovered in this case, that recovery be treated similarly to the recovery for Economic Development Incentives ("EDI").

Q. How are EDI avoided revenues recovered?

A. When rates are developed for compliance tariffs, the amount of EDI credits that are expected under the increased revenue requirement are estimated. This estimated amount of avoided revenue is then allocated to all classes for recovery on the basis of the otherwise-applicable class revenue requirements.

Q. Could it also be reasonable to treat the avoided revenue as a program expense that is included in the cost of service calculation and remove the revenue from the residential class revenue calculation?

A. Yes.

<u>CONCLUSION</u>

Q. Does this conclude your rebuttal 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 *Rebuttal 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 6th day of August 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

Utility Tariffs for Large Load Customers in Missouri

In 2025, Senate Bill 4 was passed by the General Assembly and signed by Governor Kehoe. It required the Missouri Public Service Commission (PSC) to adopt rates for large load customers — including data centers — that reflect those customers' share of their costs and prevented other customers — like residential and commercial customers — from being charged any unjust or unreasonable costs arising from service to large load customers. Two of Missouri's three regulated electric utility companies, Ameren Missouri and Evergy, have approved large-load tariffs. Liberty Utilities' large load tariff case is currently in progress.

In its approval of large load tariffs, the PSC adopted provisions designed to protect residential and small-business customers from costs related to data centers, including:

- **Minimum Service Contracts.** Large-load customers must take service for a minimum of 12 years, with the option of taking an additional 5 years as a "ramp up" period until fully using their projected amount of energy, for a potential 17-year commitment.
- **Financial Security and Collateral Requirements.** Large load customers must meet creditworthiness and liquidity requirements as well as provide collateral in the amount of two years of minimum monthly bills.
- **Exit and Early Termination Fees.** Large-load customers may terminate or change rate schedules before the end of the contract term if written notice is provided at least 24 months prior to the requested change taking effect. In those instances, the customer will be subject to an exit fee. If requesting to terminate with less than 24 months' notice, the customer is also subject to an early termination fee.
- **Minimum Monthly Bill.** Each large-load customer bill will include the sum of all applicable charges, including a monthly demand charge set at 80% of the agreed upon rate.
- **Cost Stabilization Recovery.** This requirement ensures that the electric utility can recover all costs associated with serving large load customers and that large load customers are paying their full cost of service.
- **Optional Renewable and Carbon-Free Programs.** Large-load customers have the option to invest in additional generation and capacity programs, including nuclear and clean energy programs, at their own expense.

Ameren Large Load Tariff

https://efis.psc.mo.gov/Document/Display/859644

Evergy Large Load Tariff

https://efis.psc.mo.gov/Document/Display/865314

Submit Comment in Liberty Case ET-2026-0184

https://efis.psc.mo.gov/PublicComment/EmailForm

Missouri Public Service Commission Website

https://psc.mo.gov/default.aspx

Case No. ER-2026-0143
Schedule SLKL-r1
Page 1 of 1

Case No. ER-2026-0143

INFORMATION CONTAINED IN

SCHEDULE SLKL-r2

HAS BEEN

DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY

Missouri Public Service Commission

SPP Quarterly Update

2026 Summer Readiness Forecast

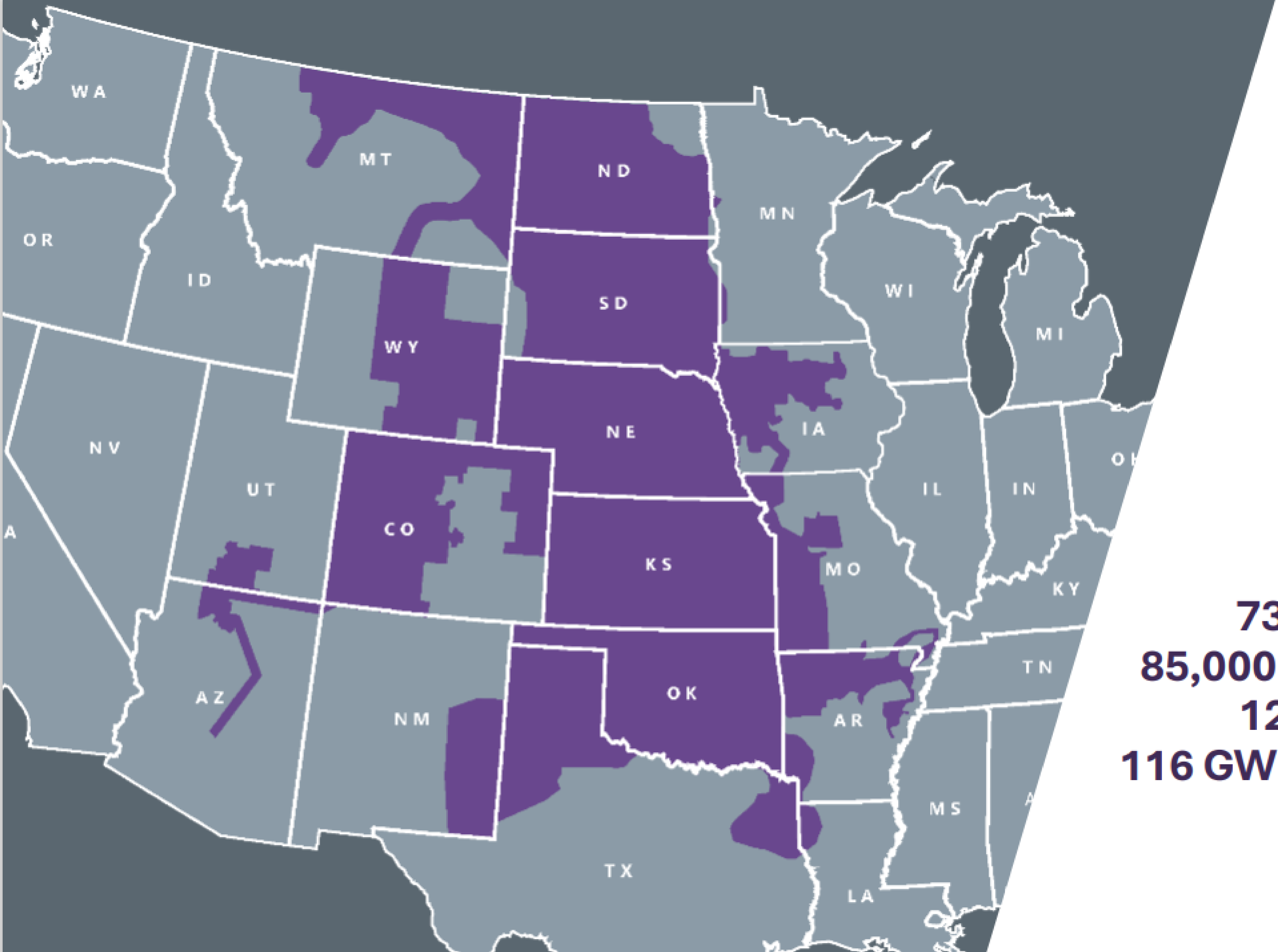
May 28, 2026

Case No. ER-2026-0143
Schedule SLKL-r3

AGENDA

- SPP Resource Adequacy Overview
- SPP Planning Reserve Margin Requirements
- Cost of New Entry (CONE)
- 2026 Summer Preparedness & Reliability Outlook

SPP Resource Adequacy Overview



The SPP RTO

as of 4/1/2026

17 states
20 million people
732,000 square miles
85,000 transmission miles
1200 generating units
116 GW registered capacity
5,700 substations

Balancing Electric Supply and Demand

SUPPLY/GENERATION

- **107,502 MW** Nameplate Capacity *(as of March 2026)*
- **65,639 MW** Accredited Capacity *(as of Summer 2025)*

DEMAND/LOAD

- **56,184 MW** all-time coincident peak load (8/21/23)
- **48,142 MW** Winter peak (2/20/25)

What is Resource Adequacy

SPP Regional State Committee

Primary responsibility for:

- Cost allocation for transmission upgrades
- **Approach for regional resource adequacy**
- Allocation of transmission rights in SPP markets
- Planning for remote resources

Resource Adequacy Requirements

Attachment AA of SPP Tarriff requires SPP to have sufficient capacity to serve the SPP East and West Balancing Authority Areas' peak demand.

Load Responsible Entities are required to maintain the capacity required to meet their load and planning reserve obligations.

SPP RESOURCE ADEQUACY CONSTRUCT

SPP RELIABILITY

- WINTER Resource Adequacy Requirement
- Planning Reserve Marge (PRM)
- LONG-TERM PRM POLICY

RESOURCE ACCREDITATION

- Performance Based Accreditation
- Effective Load Carrying Capability

RESOURCE AVAILABILITY

- AVAILABILITY
- OUTAGE POLICY
- FUEL ASSURANCE
- Expedited Resource Adequacy Study (ERAS)

INCENTIVES

- PRM Sufficiency Valuation Curve
- DEFCIENCY PAYMENT NON-VIOLATION

How SPP's Resource Adequacy Construct works

SPP tasks

Load Responsible Entity Forecast Submittals

- Load Forecasts
- Resource Plans
- Future year projections

SPP Loss-of Load Expectation (LOLE) Study

- Evaluates 1 day in 10 years reliability standard
- Determined accredited capacity needs

Base Planning Reserve Margin (PRM) Determination

- Establishes Base PRM from LOLE Study

Capacity Accreditation

Performance Based Accreditation (PBA)
For thermal and hydro resources

Effective Load Carrying Capability (ELCC)
For wind, solar, and storage resources

Accredited Planning Reserve Margin Determination

- Sets Accreditation Capacity Planning Reserve Margin (ACAP) requirements based on accreditation of thermal resources

Compliance & Enforcement

- Review LRE submittals to comply with the Resource Adequacy Requirement
- Assesses deficiency payments

How SPP's RA Construct works:

Load Responsible Entities (LRE) tasks

Determine load forecasts and resource plans for the applicable future years and provide to SPP for analysis.

Submit updated load forecast and demonstrate qualified capacity in sufficient amounts to meet their load forecast and the Planning Reserve Margin (PRM) for the applicable season

- Qualified capacity can include: existing resources | new resources | bi-lateral power purchase agreements
- Qualified capacity may be internal or external to the SPP Balancing Authority
  - All qualified external capacity must have Firm Transmission Service to the SPP B.A.
- If SPP determines an LRE is deficient, LRE has 45 days to cure the deficiency: May acquire additional capacity, usually through contracts

Ensure qualified capacity is available throughout the season

All LREs have their Resource Adequacy position validated for compliance with the Resource Adequacy Requirement

Deficient LREs are assigned a Deficiency Payment in the amount of capacity shortage (Based on Cost of New Entry (CONE))

SPP's Planning Reserve Margin Requirements

SPP Planning Reserve Margin (PRM) Requirements

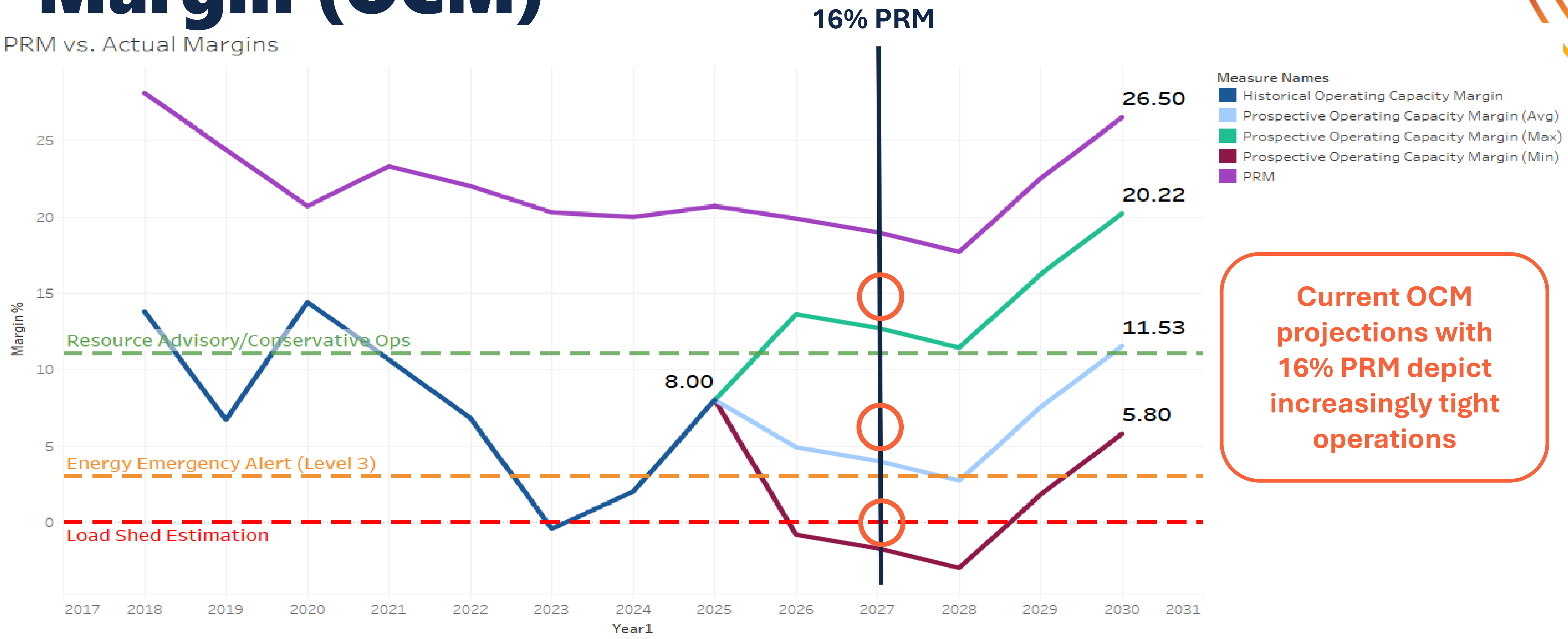
SPP East Balancing Authority Area (BAA)

- (Current) Summer PRM: 16%
  - 2026 Accredited Capacity PRM (ACAP PRM) – 7.06%
- (Current) Winter PRM: 36%
  - 2026-2027 Winter ACAP PRM - TBD
- Based on Loss of Load Expectation (LOLE) studies

SPP West Balancing Authority Area (BAA)

- (RSC/BOD Approved) Summer 2027 PRM: 19%
- (RSC/BOD Approved) Winter 2027-2028 PRM: 40%
- Based on preliminary LOLE Study in 2024-2025

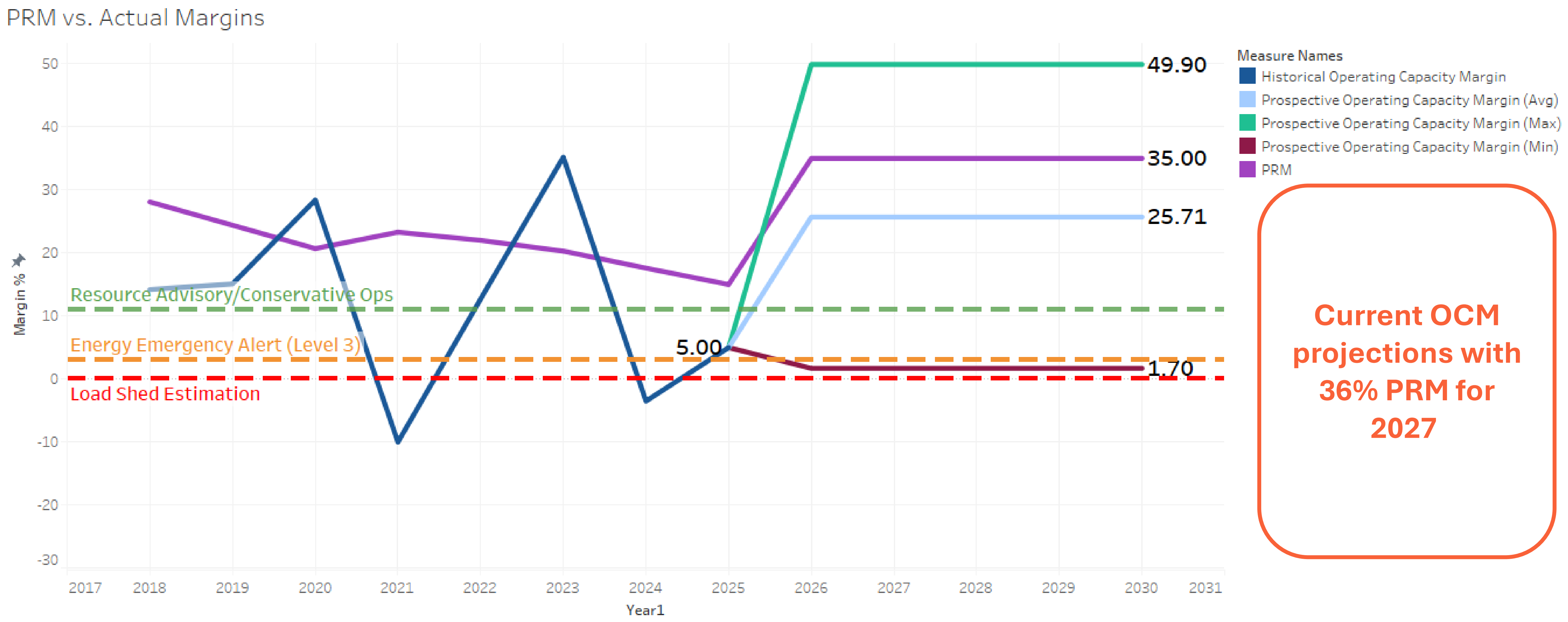
Summer PRM vs. Operating Capacity Margin (OCM)



Current OCM projections with 16% PRM depict increasingly tight operations

Operating Capacity Margin (OCM) – Minimum value per year of total capacity MWs available minus load shown as a percentage of the load (Note the Worst Weather Event (WWE) has been excluded.)

Winter PRM vs. Operating Capacity Margin (OCM)



Current OCM projections with 36% PRM for 2027

Operating Capacity Margin (OCM) – Minimum value per year of total capacity MWs available minus load shown as a percentage of the load

Missouri Resource Adequacy Outlook

- Missouri's Load Responsible Entities (LRE)
  - Evergy Metro (formerly KCPL, GMO)
  - Liberty Utilities
  - City of Carthage
  - Independence Power & Light
  - City of Kennett
  - City of Malden
  - Missouri Joint Municipal Electric
  - City of Nixa
  - City of Poplar Bluff
  - City of Sikeston
  - City Utilities of Springfield
  - City of West Plains

2026 Summer Season Missouri Outlook	
2026 Summer ACAP PRM – 7.06%	
Capacity Resources	8,541.55 MW
Firm Capacity Purchases	1,741.04 MW
Firm Capacity Sales	696.90 MW
External Firm Power Purchases	198.28 MW
Total Capacity	**9,783.97 MW**
Summer Peak Demand	8,906.10 MW
Demand Response Available	283.29 MW
Internal Firm Power Purchases	40.00 MW
Internal Firm Power Sales	-
Net Peak Demand	8,582.81 MW
ACAP Planning Reserve Margin (ACAP PRM)	7.06%
Resource Adequacy Requirement	**9,188.75 MW**
Excess or deficient	595.22 MW
LRE Planning Reserve Margin (PRM)	14%

Cost of New Entry (CONE)

Cost of New Entry (CONE)

What is CONE?

- Estimates the cost of constructing and operating a new reference generation resource. (Combustion Turbine – Simple Cycle Plant)

Why Does it Matter?

- CONE serves as the basis of the Deficiency Payment for LREs found not meeting the RAR
- Outside of RA, SPP CONE serves as an economic benchmark used in transmission planning, market analysis, reliability studies, and long-term resource planning.

CONE Updates

- Reviewed and updated periodically
- Reflects inflation, financing costs, capital costs, and technology assumptions

SPP's Revised Cost of New Entry (CONE)

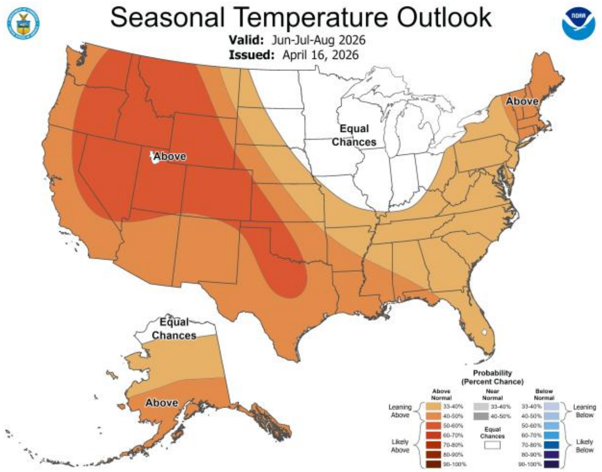
- RSC approved an update to CONE value at its February 2026 Meeting.
- CONE increased from ~$85.61/kW-year to **$139.85/kW-year**.
- The new value becomes effective for the Summer 2026 Resource Adequacy season.

2026 Summer Preparedness

What is the outlook for Summer 2026?

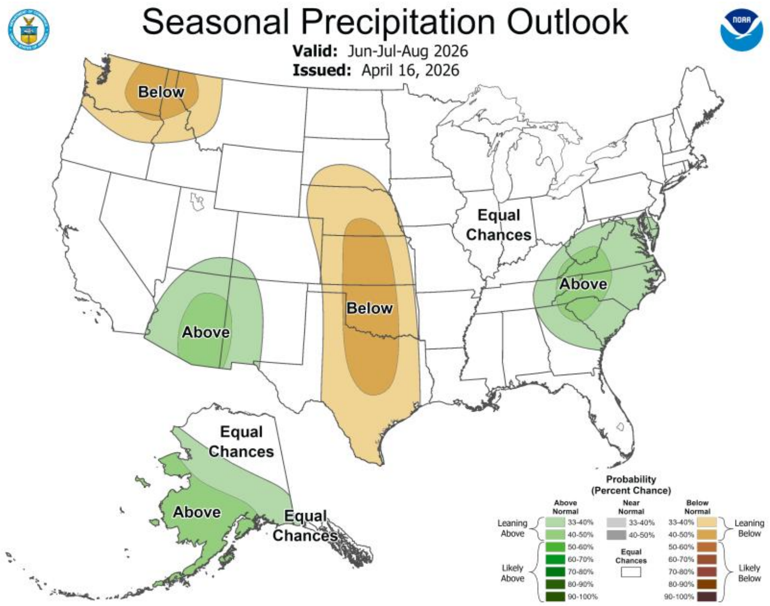
Total Net Peak Demand	Accredited Capacity (ACAP) PRM	Resource Adequacy Requirement	Total Capacity	SPP Balancing Authority Reserve Margin
57,245 MW Demand Response **1,814 MW**	**7.06 %**	**61,287 MW**	**~68,000 MW**	**~19%**

Summer 2026 Outlook



Warmer than average temperatures likely for southern and western portions of the East BAA and West BAA– medium confidence

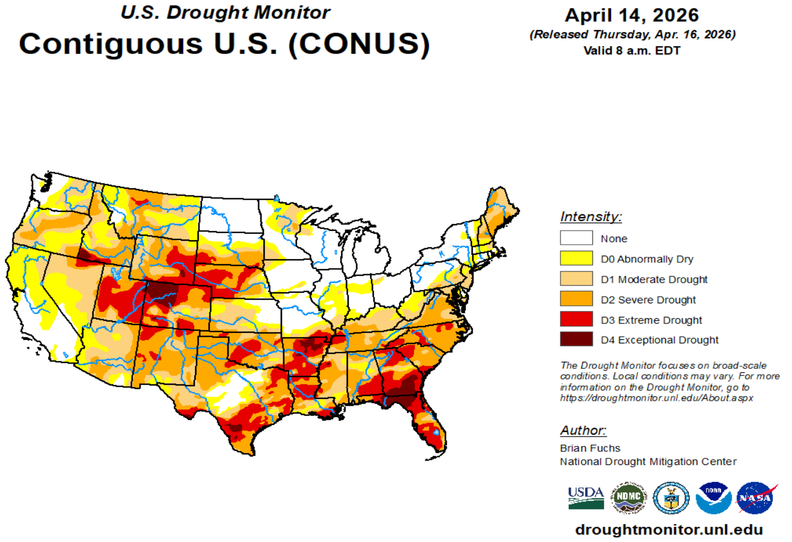
Warmer than average temperatures favored central and northern BA – low confidence



Below average rainfall favored central and southern BA – low confidence

Potential drought may worsen

Need to watch for low water levels for thermal generation



Severe to extreme drought for much of eastern BA area

Extreme to exceptional drought much of western BA area

Low water levels may impact thermal generation

Potentially low reservoir levels may impact hydro generation

Load and Outages for Each Model

Area	Month	Load	Transmission Outages	Generation Outages
SPP Eastern Interconnection	June	~53,200MW	69	~7,200MW
SPP Eastern Interconnection	July	~55,400MW	31	~1,300MW
SPP Eastern Interconnection	August	~55,700MW	29	~1,900MW
SPP Eastern Interconnection	September	~52,000MW	76	~12,500MW
SPP West RC	June	~17,600MW	13	~2,800MW
SPP West RC	July	~18,500MW	10	~1,700MW
SPP West RC	August	~18,300MW	10	~1,600MW
SPP West RC	September	~16,800MW	9	~3,400MW

SPP Summer 2026 Reliability Assessment

Study Report

- Final Report posted on Globalscape for TOPs
- 2026 Summer Operations within the SPP Balancing Authority and Reliability Coordinator Area footprints are expected to be normal with no forecast of extreme operational situations.
- Transmission constraints and mitigations are expected to be manageable to maintain the required reliable operating criteria.
- If extreme hot temperatures, higher than normal outages, or a high amount of uncertainty occur, SPP may issue notifications of heightened grid conditions.

Appendix

2025 Summer Assessment

RTO/ISO	SELECTED DATE	EQUIPMENT	TYPE	TOTAL
SPP	6/2/2025	Lines/Transformers	Planned	80
SPP	6/1/2024-9/30/2024	Lines/Transformers	Unplanned	42
SPP	**Total**	**Lines/Transformers**	**Planned/Unplanned**	**122**
SPP	9/30/2024	Generators	Planned	~ 8,800 MW
SPP	6/1/2023-9/31/2023	Generators	Unplanned	~ 10,900 MW
SPP	**Total**	**Generators**	**Planned/Unplanned**	**~ 19,700 MW**

2025 Seasonal Assessment Assumptions Used vs. Actual Values

RTO/ISO	SELECTED DATE	EQUIPMENT	TYPE	TOTAL	Actual
SPP	6/2/2025	Lines/Transformers	Planned	80	122 (9/30)
SPP	6/1/2024-9/30/2024	Lines/Transformers	Unplanned	42	42 (9/30)
SPP	**Total**	**Lines/Transformers**	**Planned/Unplanned**	**122**	**163 (9/30/25)**
SPP	9/30/2024	Generators	Planned	~ 8,800 MW	~8,300MW (9/26)
SPP	6/1/2023-9/31/2023	Generators	Unplanned	~ 10,900 MW	~12,300MW (9/26)
SPP	**Total**	**Generators**	**Planned/Unplanned**	**~ 19,700 MW**	**~20,600 MW**

Thank you!

CONTACT

Casey Cathey
Vice President, Engineering

Kim O’Guinn
Senior Director, State Regulatory Policy

Monsherra Blank
Manager, Regulatory Affairs

TYPE	VOLTAGE_CLASS	VOLTAGE	Phase	FEET	MILES
OH	Distribution	12.47kV wye	3	18,760,652	3,553
OH	Distribution	2.4kV 1ph, wye	1	72,423	14
OH	Distribution	34.5kV wye	3	3,583,359	679
OH	Distribution	25.0kV wye	3	472	0
OH	Distribution	4.16kV wye	3	103,318	20
OH	Distribution	4.80kV wye	3	354	0
OH	Distribution	13.2kV wye	3	9,361,767	1,773
OH	Distribution	7.62kV 1ph, wye	1	2,654,068	503
OH	Distribution	13.8kV wye	3	72,618	14
OH	Distribution	7.2kV 1ph, wye	1	19,918,586	3,772
OH	Distribution	19.9kV 1ph, wye	1	1,432	0
UG	Distribution	7.2kV 1ph, wye	1	4,117,121	780
UG	Distribution	34.5kV wye	3	13,224	3
UG	Distribution	2.4kV 1ph, wye	1	2,065	0
UG	Distribution	25.0kV wye	3	9,201	2
UG	Distribution	12.47kV wye	3	6,210,121	1,176
UG	Distribution	8.32kV wye	3	9,909	2
UG	Distribution	4.16kV wye	3	112,595	21
UG	Distribution	4.80kV wye	3	1,659	0
UG	Distribution	13.2kV wye	3	9,067,958	1,717
UG	Distribution	14.4kV 1ph, wye	1	20	0
UG	Distribution	7.97kV 1ph, wye	1	114	0
UG	Distribution	7.62kV 1ph, wye	1	267,108	51
UG	Distribution	13.8kV wye	3	3,483	1
OH	Secondary	120/240V 1ph	1	24,172,251	4,578
OH	Secondary	120/240V 3ph, delta	3	3,837	1
OH	Secondary	480V 1ph	1	147,953	28
OH	Secondary	240/480V 1ph	1	29,273	6
OH	Secondary	120V 1ph	1	41,703	8
OH	Secondary	240V 1ph	1	518,607	98
OH	Secondary	Unknown	3	1,733,009	328
OH	Secondary	240/480V 3ph, delta	3	3,667	1
OH	Secondary	277V 1ph	1	2,507	0
OH	Secondary	277/480V 3ph, wye	3	64,649	12
OH	Secondary	120/208V 3ph, wye	3	814,238	154
UG	Secondary	120/240V 1ph	1	7,798,699	1,477
UG	Secondary	120/240V 3ph, delta	3	6,066	1
UG	Secondary	480V 1ph	1	5,729	1
UG	Secondary	240V 1ph	1	16,334	3
UG	Secondary	120V 1ph	1	28,778	5
UG	Secondary	240/480V 1ph	1	11,641	2
UG	Secondary	Unknown	3	269,391	51
UG	Secondary	277V 1ph	1	4,614	1
UG	Secondary	277/480V 3ph, wye	3	5,671	1
UG	Secondary	120/208V 3ph, wye	3	244,688	46

TYPE	VOLTAGE_CLA!	VOLTAGE	Pha	FEET	Numbe	MILES	Phase Size	Neutral Size	Numbe	Numbe	MatID F	MatID N	Cost pe	Cost pe	Cost Total
OH	Distribution	12.47kV wye	3	18760652	5280	3553	477 AAC (19)	3/0 ACSR (6/1)	3	1	420159	420009	1.833	0.711	$ 116,503,649
OH	Distribution	2.4kV 1ph, wye	1	72423	5280	14	#2 ACSR (6/1)	#2 ACSR (6/1)	1	1	420005	420005	0.367	0.367	$ 53,158
OH	Distribution	34.5kV wye	3	3583359	5280	679	477 AAC (19)	3/0 ACSR (6/1)	3	1	420159	420009	1.833	0.711	$ 22,252,659
OH	Distribution	25.0kV wye	3	472	5280	0	477 AAC (19)	3/0 ACSR (6/1)	3	1	420159	420009	1.833	0.711	$ 2,931
OH	Distribution	4.16kV wye	3	103318	5280	20	477 AAC (19)	3/0 ACSR (6/1)	3	1	420159	420009	1.833	0.711	$ 641,605
OH	Distribution	4.80kV wye	3	354	5280	0	477 AAC (19)	3/0 ACSR (6/1)	3	1	420159	420009	1.833	0.711	$ 2,198
OH	Distribution	13.2kV wye	3	9361767	5280	1773	477 AAC (19)	3/0 ACSR (6/1)	3	1	420159	420009	1.833	0.711	$ 58,136,573
OH	Distribution	7.62kV 1ph, wye	1	2654068	5280	503	#2 ACSR (6/1)	#2 ACSR (6/1)	1	1	420005	420005	0.367	0.367	$ 1,948,086
OH	Distribution	13.8kV wye	3	72618	5280	14	477 AAC (19)	3/0 ACSR (6/1)	3	1	420159	420009	1.833	0.711	$ 450,958
OH	Distribution	7.2kV 1ph, wye	1	19918586	5280	3772	#2 ACSR (6/1)	#2 ACSR (6/1)	1	1	420005	420005	0.367	0.367	$ 14,620,242
OH	Distribution	19.9kV 1ph, wye	1	1432	5280	0	#2 ACSR (6/1)	#2 ACSR (6/1)	1	1	420005	420005	0.367	0.367	$ 1,051
UG	Distribution	7.2kV 1ph, wye	1	4117121	5280	780	1/0 AAC (7)	Concentric	1	1	000096010	Bundled	4.78	0	$ 19,679,838
UG	Distribution	34.5kV wye	3	13224	5280	3	750 AAC (37)	Concentric	3	1	460021	Bundled	38.917	0	$ 1,543,915
UG	Distribution	2.4kV 1ph, wye	1	2065	5280	0	1/0 AAC (7)	Concentric	1	1	000096010	Bundled	4.78	0	$ 9,871
UG	Distribution	25.0kV wye	3	9201	5280	2	1000 AAC (61)	Concentric	3	1	460016	Bundled	39.7	0	$ 1,095,839
UG	Distribution	12.47kV wye	3	6210121	5280	1176	1000 AAC (61)	Concentric	3	1	460291	Bundled	38.626	0	$ 719,616,401
UG	Distribution	8.32kV wye	3	9909	5280	2	1000 AAC (61)	Concentric	3	1	460291	Bundled	38.626	0	$ 1,148,235
UG	Distribution	4.16kV wye	3	112595	5280	21	1000 AAC (61)	Concentric	3	1	460291	Bundled	38.626	0	$ 13,047,283
UG	Distribution	4.80kV wye	3	1659	5280	0	1000 AAC (61)	Concentric	3	1	460291	Bundled	38.626	0	$ 192,242
UG	Distribution	13.2kV wye	3	9067958	5280	1717	1000 AAC (61)	Concentric	3	1	460291	Bundled	38.626	0	$ 1,050,776,837
UG	Distribution	14.4kV 1ph, wye	1	20	5280	0	1/0 AAC (7)	Concentric	1	1	460705	Bundled	3.432	0	$ 69
UG	Distribution	7.97kV 1ph, wye	1	114	5280	0	1/0 AAC (7)	Concentric	1	1	000096010	Bundled	4.78	0	$ 545
UG	Distribution	7.62kV 1ph, wye	1	267108	5280	51	1/0 AAC (7)	Concentric	1	1	000096010	Bundled	4.78	0	$ 1,276,776
UG	Distribution	13.8kV wye	3	3483	5280	1	1000 AAC (61)	Concentric	3	1	460291	Bundled	38.626	0	$ 403,603
OH	Secondary	120/240V 1ph	1	24172251	5280	4578	4/0 AAC (18)	2/0 ACSR (6/1)	2	1	420222	Bundled	2.328	0	$ 112,546,001
OH	Secondary	120/240V 3ph, delta	3	3837	5280	1	336 AAC (19)	336 ACSR (18.1)	3	1	420207	Bundled	4.45	0	$ 51,224
OH	Secondary	480V 1ph	1	147953	5280	28	4/0 AAC (18)	2/0 ACSR (6/1)	2	1	420222	Bundled	2.328	0	$ 688,869
OH	Secondary	240/480V 1ph	1	29273	5280	6	4/0 AAC (18)	2/0 ACSR (6/1)	2	1	420222	Bundled	2.328	0	$ 136,295
OH	Secondary	120V 1ph	1	41703	5280	8	#4 AAC (7)	#4 ACSR (6/1)	1	1	420228	Bundled	0.52	0	$ 21,686
OH	Secondary	240V 1ph	1	518607	5280	98	4/0 AAC (18)	2/0 ACSR (6/1)	2	1	420222	Bundled	2.328	0	$ 2,414,634
OH	Secondary	Unknown	3	1733009	5280	328	336 AAC (19)	336 ACSR (18.1)	3	1	420207	Bundled	4.45	0	$ 23,135,670
OH	Secondary	240/480V 3ph, delta	3	3667	5280	1	336 AAC (19)	336 ACSR (18.1)	3	1	420207	Bundled	4.45	0	$ 48,954
OH	Secondary	277V 1ph	1	2507	5280	0	#4 AAC (7)	#4 ACSR (6/1)	1	1	420228	Bundled	0.52	0	$ 1,304
OH	Secondary	277/480V 3ph, wye	3	64649	5280	12	336 AAC (19)	336 ACSR (18.1)	3	1	420207	Bundled	4.45	0	$ 863,064
OH	Secondary	120/208V 3ph, wye	3	814238	5280	154	336 AAC (19)	336 ACSR (18.1)	3	1	420207	Bundled	4.45	0	$ 10,870,077
UG	Secondary	120/240V 1ph	1	7798699	5280	1477	4/0 AAC (19)	2/0 AAC (19)	2	1	460713	Bundled	2.37	0	$ 36,965,833
UG	Secondary	120/240V 3ph, delta	3	6066	5280	1	350 AAC (37)	4/0 AAC (19)	3	1	460710	Bundled	5.101	0	$ 92,828
UG	Secondary	480V 1ph	1	5729	5280	1	4/0 AAC (19)	2/0 AAC (19)	2	1	460713	Bundled	2.37	0	$ 27,155
UG	Secondary	240V 1ph	1	16334	5280	3	#6 AAC (7)	#6 AAC (7)	1	1	0142000	Bundled	0.5	0	$ 8,167
UG	Secondary	120V 1ph	1	28778	5280	5	#6 AAC (7)	#6 AAC (7)	1	1	0142000	Bundled	0.5	0	$ 14,389
UG	Secondary	240/480V 1ph	1	11641	5280	2	4/0 AAC (19)	2/0 AAC (19)	2	1	460713	Bundled	2.37	0	$ 55,178
UG	Secondary	Unknown	3	269391	5280	51	350 AAC (37)	4/0 AAC (19)	3	1	460710	Bundled	5.101	0	$ 4,122,490
UG	Secondary	277V 1ph	1	4614	5280	1	#6 AAC (7)	#6 AAC (7)	1	1	0142000	Bundled	0.5	0	$ 2,307
UG	Secondary	277/480V 3ph, wye	3	5671	5280	1	350 AAC (37)	4/0 AAC (19)	3	1	460710	Bundled	5.101	0	$ 86,783
UG	Secondary	120/208V 3ph, wye	3	244688	5280	46	350 AAC (37)	4/0 AAC (19)	3	1	460710	Bundled	5.101	0	$ 3,744,460

Case No. ER-2026-0143

INFORMATION CONTAINED IN

SCHEDULE SLKL-r6

HAS BEEN

DEEMED

CONFIDENTIAL

IN ITS ENTIRETY

Evergy Missouri Metro
Case Name: 2026 Evergy MO Metro Rate Case
Case Number: ER-2026-0143

Requestor Gonzales Marina -
Response Provided April 10, 2026

Question:0316

Referring to the workpaper CONFIDENTIAL Support Paper Conductor Min System Analysis, please provide all relevant and supporting documents for the hardcoded values found on the following tabs: a) Line Mile Cost Estimates b) MS_1 mile #2ACSR w_switches c) MS_300' #2Al, conduit, trench If expert judgement was used to determine the values, please explain who provided the hardcoded values and how they were calculated.

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

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

Response:

The estimates were developed using Evergy's standard construction units in coordination with standard design and estimating applications. The standard construction units include labor quantities and material units, and the estimating application combines labor cost, material cost, and estimated overheads.

Information provided by:
Brandon Tiesing, Sr Mgr Design & Planning
Carmen Estrada, Lead Reg Project Coordinator

Attachment(s): n/a

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

Signature /s/ *Brad Lutz*
Director Regulatory Affairs

Evergy Missouri Metro
Case Name: 2026 Evergy MO Metro Rate Case
Case Number: ER-2026-0143

Requestor Lange Sarah -
Response Provided May 04, 2026

Question:0341

A. Please provide either or both the historic average cost, on a per-foot basis, of the overhead conductor necessary to serve a 120/240 volt customer with a peak demand of 25 kW, using "Evergy's standard construction units in coordination with standard design and estimating applications," as that phrase was used in Evergy's April 10 response to Staff DR 316. B. Please provide either or both the historic average cost, on a per-foot basis, of the underground conductor necessary to serve a 120/240 volt customer with a peak demand of 25 kW, using "Evergy's standard construction units in coordination with standard design and estimating applications," as that phrase was used in Evergy's April 10 response to Staff DR 316. C. Please provide a breakdown of the estimates provided in response to parts A and B by FERC account and by recorded item. D. Please provide all supporting workpapers and any appropriate narrative explanations of the calculations provided in response to parts A, B, and C.

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

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

Response:
Evergy is unable to provide a meaningful "historic average cost" on a per-foot basis for the overhead or underground conductor necessary to serve a 120/240-volt customer with a peak demand of 25 kW, as requested.

The request presumes the existence of a representative or "average" project to serve such a customer; however, no such average project exists in practice. Projects involving 120/240-volt customers span a wide range of scopes and configurations, from very small installations serving a single customer to large-scale distribution extensions serving numerous customers simultaneously.

As a result, conductor costs per foot vary significantly depending on project-specific factors, including but not limited to the number of customers served, total project length, construction type (overhead versus underground), and local design and construction conditions. Without additional parameters defining the project context, any average per-foot cost would be arbitrary and potentially misleading.

Information provided by: Brandon Tiesing, Sr Mgr Design & Planning

Attachment(s):

Missouri Verification:

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

Signature /s/ *Brad Lutz*
Director Regulatory Affairs

Evergy Missouri Metro
Case Name: 2026 Evergy MO Metro Rate Case
Case Number: ER-2026-0143

Requestor Lange Sarah -
Response Provided April 08, 2026

Question:0291

A. Please provide a listing of single phase secondary voltage line segments recorded to accounts 364 Poles, towers and fixtures and 365 Overhead conductors and devices, and for each identify the operating voltage and the length of the segment.

B. Please provide a listing of single phase secondary voltage line segments recorded to accounts 366 Underground conduit and 367 Underground conductors and devices, and for each identify the operating voltage and the length of the segment.

C. Please provide a listing of three phase secondary voltage line segments recorded to accounts 364 Poles, towers and fixtures and 365 Overhead conductors and devices, and for each identify the operating voltage and the length of the segment.

D. Please provide a listing of three phase secondary voltage line segments recorded to accounts 366 Underground conduit and 367 Underground conductors and devices, and for each identify the operating voltage and the length of the segment.

E. Please provide a listing of single phase primary voltage line segments recorded to accounts 364 Poles, towers and fixtures and 365 Overhead conductors and devices, and for each identify the operating voltage and the length of the segment.

F. Please provide a listing of single phase primary voltage line segments recorded to accounts 366 Underground conduit and 367 Underground conductors and devices, and for each identify the operating voltage and the length of the segment.

G. Please provide a listing of three phase primary voltage line segments recorded to accounts 364 Poles, towers and fixtures and 365 Overhead conductors and devices, and for each identify the operating voltage and the length of the segment.

H. Please provide a listing of three phase primary voltage line segments recorded to accounts 366 Underground conduit and 367 Underground conductors and devices, and for each identify the operating voltage and the length of the segment.

evergy

I. Please provide a listing of high voltage line segments recorded to accounts 364 Poles, towers and fixtures and 365 Overhead conductors and devices, and for each identify the operating voltage and the length of the segment.

J. Please provide a listing of high voltage line segments recorded to accounts 366 Underground conduit and 367 Underground conductors and devices, and for each identify the operating voltage and the length of the segment

K. Please explain any assets recorded to accounts 364, 365, 366, or 367 which are not part of the infrastructure referenced in parts A-J of this question.

L. If answers to parts A-J of this question are not fully available, please identify the number of interconnections between secondary voltage lines and higher voltage lines, and please identify the number of single phase segments recorded to accounts 364, 365, 366, or 367.

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

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

Response:

Objection:
The Company objects to the Data Request as vague, overly broad, unduly burdensome, ambiguous, calls for speculation, not reasonably calculated to lead to the discovery of admissible evidence, and not relevant or material to the subject matter of this proceeding. The Company will not provide a response to Data Requests that ask for estimates, analysis, or calculations that have not been performed by the Company. Additionally, the Company will not provide a response to Data Requests that seek documents or document formats not created or maintained in the Company's ordinary course of business.

The Company will provide responses to the Data Request subject to the objections asserted above.

Questions A through K.

- The Company does not book assets by segment, nor are they differentiated by voltage within these accounts.

Question L.

- Secondary voltage lines are not interconnected directly with higher voltage lines. In most cases, higher voltage lines are connected to the "input" side of a transformer, and the secondary voltage lines are connected to the "output" side of the transformer. Based on a recent count from the mapping system, there are 42,564 overhead transformers and 19,077 underground transformers identified in the Missouri Metro jurisdiction. Note, counts for field installed units will not follow accounting for the transformers in our plant records.

- The Company does not book assets by segment.

Information provided by: Brad Lutz, Regulatory Affairs

Attachment(s):

Missouri Verification:

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

Signature /s/ *Brad Lutz*
Director Regulatory Affairs

Evergy Missouri Metro
Case Name: 2026 Evergy MO Metro Rate Case
Case Number: ER-2026-0143

Requestor Lange Sarah -
Response Provided March 30, 2026

Question:0243

1. Refer to Lutz Direct testimony at page 11, stating "Informal conversations with, and testimony by Staff have raised questions about reactive demand and if changes in regional generations fleets should require changes to rate design approaches related to reactive demand." Please clarify whether those conversations or testimony related to increasing or decreasing the scrutiny applied to consideration of aligning the revenue responsibility for reactive demand with the cost of service associated with ensuring adequacy of reactive power. Please confirm that Staff did not encourage the elimination of existing reactive demand charges at Evergy Missouri Metro.

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

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

Response:

As stated originally in my ER-2024-0189 direct testimony, the conversation centered around Staff's observation of retirements of traditional rotating mass generation such as coal or gas and increases in inverter-based generation within Missouri and their wish to confirm the ratemaking treatment is appropriate.

Confirmed. Staff did not encourage the elimination of existing reactive demand charges at Evergy Missouri Metro.

Information provided by: Brad Lutz, Regulatory Affairs

Attachment(s):

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

Signature /s/ *Brad Lutz*
Director Regulatory Affairs