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Direct Testimony of Angela Schaben
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DIRECT TESTIMONY

OF

ANGELA SCHABEN

Submitted on Behalf of the Office of the Public Counsel

EVERGY METRO, INC. D/B/A EVERGY MISSOURI METRO

CASE NO. ER-2026-0143

** _____ **

Denotes Confidential Information that has been redacted

June 30, 2026

PUBLIC

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DIRECT TESTIMONY

OF

ANGELA SCHABEN

EVERGY MISSOURI METRO, INC. D/B/A EVERGY MISSOURI METRO

CASE NO. ER-2026-0143

INTRODUCTION

Q. Please state your name, title, and business address.

A. Angela Schaben, Senior Utility Regulatory Auditor, Office of the Public Counsel ("OPC" or "Public Counsel"), P.O. Box 2230, Jefferson City, Missouri 65102.

Q. What are your qualifications and experience?

A. Please refer to the Schedule ADS-D-1 attached hereto.

Q. Have you previously testified before the Missouri Public Service Commission?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony regards Evergy Missouri Metro ("EMM") past rate case proposals related to various cost tracking and how cost tracking mechanisms affect traditional ratemaking. Additionally, my testimony regards Fuel Adjustment Clause ("FAC") tariff sheets, monthly FAC reporting, and long-term capacity.

Q. Please would you summarize your recommendations?

A. Summarized, my recommendations to the Commission are:

1. Continue with the practice of approving cost tracking mechanisms only in volatile or extraordinary circumstances.

2. Order the clarification of the Company's proposed FAC tariff sheet language in several areas and continue to exclude long-term and short-term capacity contracts from recovery through the Company's FAC.

REGULATORY TRACKERS AND RELATED POLICY CONCERNS

Q. Can you please explain what a "Tracker" is for regulatory purposes?

A. Expense tracking mechanisms, or "trackers," compare actual costs to the amounts for those costs included in a company's revenue requirement used to set its rates, and defer the difference to future rate cases to ensure, in theory, that over time the company's cost recovery for the tracked costs better matches its actual costs than what the company would experience if it did not track its actual costs. Companies typically request trackers that increase their revenues beyond those available from normal rate case processes.

Q. What trackers has EMM proposed in past cases?

A. The Company has requested various tracking mechanisms in prior rate cases, including, but not limited to, trackers for: property tax, bad debt, cybersecurity, storm reserves. The Company has justified its requests for these trackers primarily based on the effects of regulatory lag.

Q. Has the Commission authorized the Company to use any of the trackers that it has requested in the past?

A. At least one, that I have found. Due to Senate Bill 745, signed by Governor Parson on June 29, 2022, Evergy was granted a property tax tracker in ER-2022-0129/0130. The statute went into effect on August 28, 2022.

Q. Do trackers affect a utility's incentive for efficient management?

A. Yes. A paper published by NRRI entitled "How Should Regulators View Cost Trackers?" points out that cost trackers potentially diminish efficient management of regulatory activities:

> Cost trackers can reduce utility efficiency. "Just and reasonable" rates require that customers do not pay for costs the utility could have avoided with efficient or prudent management. Regulation attempts to protect customers from excessive utility costs by scrutinizing a utility's costs in a rate case, conducting

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> a retrospective review of costs, applying performance based incentives, and instituting regulatory lag. Cost trackers diminish one or more of these regulatory activities. In some cases, they diminish all of them. The consequence is the increased likelihood that customers will pay for excessive utility costs.[1]

Since utilization of cost trackers reduces business risk relating to prudent or efficient management practices, the risk and regulatory lag reduction should be factored into the return on equity ("ROE") rate.[2]

Q. In your opinion, by what standard should trackers be evaluated in Missouri?

A. In my opinion, as a type of accounting authority order ("AAO"), they should be used sparingly and only for unusual and infrequent occurrences. In File No. EU-2014-0077, the Commission determined that only extraordinary costs, which are "unusual and infrequent" are appropriately recovered through trackers. The Commission held:

> In Missouri, rates are normally established based off of a historic test year. The courts have stated that an AAO allows the deferral of a final decision on current *extraordinary* costs until a rate case and therefore is not retroactive ratemaking. Consistent with the language in General Instruction No. 7, the Commission has evaluated the transmission costs for which Companies seek an AAO to determine if they are an unusual and infrequent occurrence. The Commission concludes they are not.[3]

Q. When has the Commission typically authorized a utility to use deferral accounting?

A. The Commission has previously approved deferral accounting, by use of a tracker or an AAO, for costs incurred resulting from (1) an Act of God or (2) new legislation or rules. For example, regarding the former circumstance, the Commission has allowed deferral accounting for costs

[1] NRRI How Should Regulators View Cost Trackers, p. 16; Schedule ADS-D-2.
[2] Id. at p. 10-11.
[3] *Report and Order*, p. 10, In the Matter of the Application of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company for the Issuance of an Accounting Authority Order Relating to Their Electrical Operations and for a Contingent Waiver of the Notice Requirement of 4 CSR 240-4.020(2), Case No. EU-2014-0077, EFIS Item No. 76 (July 30, 2014).

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the utility incurred in responding to extreme or unprecedented events, such as Storm Uri and COVID. Regarding the latter circumstance, the Commission has allowed deferral accounting resulting from certain legislation and rules, including gas pipeline replacement rules and lead water lines replacement rules, etc.

Q. Is there a reasonable basis for proposing new regulatory mechanisms to track costs between rate case test years?

A. Not at this time. The tracking mechanisms that have been previously requested by EMM relate to reoccurring costs incurred through the course of regular business operations that will eventually be addressed in a rate case.

Q. Are there other reasons why expected future cost increases should not be tracked for future recovery?

A. Yes. Electric utility revenue requirements are continually changing between test years based on real time operations and management decisions. Some utility costs could increase while other costs concurrently decrease. For example, new investments promoting efficiency should alternatively reduce maintenance costs. Attempting to isolate and track selected costs, while simultaneously overlooking continuous changes in a utility's revenue requirement that may otherwise offset those costs, opens the regulatory system up to "gaming" and could lead to excessive and unfair rates. Isolating and tracking certain costs increases for future recovery leads to "piecemeal ratemaking" that disrupts the fundamental balance of accounting matching principles, achieved by evaluating all elements of a test year revenue requirement from an equivalent point in time during formal rate cases.

Q. Are there other reasons not to track these increases?

A. Yes. Tracking mechanisms initiated for specific costs eliminates management efficiency incentives normally caused by regulatory lag. Every dollar of tracked cost is eligible for future rate recovery through deferral. Thus, management will be less inclined to aggressively pursue fiscal prudence for those costs. Instead, the company would focus on

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other business areas where cost containment impacts its earnings. Furthermore, pursuit of newer efficiencies involving any risks, or incurring additional untracked costs in connection with tracked costs, would discourage the pursuit of said efficiencies according to rational business behavior.

Q. Do new cost tracking mechanisms add to the Commission's resource commitments and regulatory responsibilities?

A. Yes. Creation of cost deferral accounting entries and carrying charges requires thorough analysis for accuracy and prudence; therefore, each cost tracking mechanism imposes additional regulatory burdens upon the Commission, its Staff, OPC, and intervenors. However, even when these regulatory burdens increase, the resources that regulators require for such critical analysis do not always increase alongside them.

Q. Has the Commission utilized any regulatory criteria, other than unusual extraordinary costs and new legally-imposed cost burdens, when evaluating whether tracking mechanism treatment is necessary for specific utility costs?

A. Yes. This Commission found that cost tracking mechanisms should only be approved on occasions when compelling circumstances substantiate deviating from the traditional ratemaking procedure of auditing all test year costs and revenues in a balanced and synchronized manner in determining a reasonable overall revenue requirement, as specified in Case No. EU-2014-0077. Additionally, costs or revenues changes deferred or tracked through a tracking mechanism should meet all the following criteria to justify preferential and exceptional rate recovery treatment:

1. Significant enough to cause a material impact upon revenue requirements and business financial performance between rate cases.
2. Cause volatile and significant swings in income and cash flows.
3. Utility management has little control or influence over cost or revenue levels.

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4. Readily verifiable through expedited regulatory reviews and straightforward administration.
5. Balanced in a manner where cost mitigating impacts are reported in a manner that adheres to test year matching principles.

Q. Regarding its consistent requests for a cybersecurity tracker, has EMM incurred historical costs to ensure physical and electronic systems security at its critical facilities?

A. Yes. Table 1 below shows the consistency between EMM cybersecurity operations and maintenance ("O&M") expenses from 2021 through 2025:

**

_____
_____
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**

Q. Does EMM incur infrastructure protection and cybersecurity costs during the normal course of business already?

A. Yes. These are not unusual or infrequent costs. The Company has consistently incurred costs to comply with established security standards and secure automated systems and facilities for several years already. As a matter of fact, Evergy's Cybersecurity/IT Committee Board meeting minutes, repeatedly provides quarterly IT Scorecard, Cybersecurity Capability Maturity Model (C2M2) Assessment, and recent GridEx

[4] EMM response to OPC DR 1100.

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participation updates. Evergy's Cybersecurity/IT Committee repeatedly reports that Evergy cybersecurity measures score higher than **_____ ** with a score in the **___ **.

Q. Does EMM have an opportunity to recover its O&M and capital costs related to newly expanded Critical Infrastructure Protection ("CIP") and cybersecurity requirements?

A. Yes. Actual costs should be captured in true up of this rate case. Furthermore, capitalized costs resulting from expanded security requirements are recorded in Plant in Service for rate base consideration during rate cases.

Q. Has EMM supplied estimated future CIP and cybersecurity compliance costs?

A. EMM provided a 2026 O&M Nonlabor NFOM ("Nonfuel Operations and Maintenance") Security budget in the amount of **_ **, which is consistent with spending in prior years. As of 04/21/2026, 2027-2030 projections were unavailable as O&M budgets were not yet formalized.[6] Projections illustrate why a CIP/ cybersecurity tracking mechanism is inappropriate. Forecasted non-labor O&M expenses are not volatile, large, or extraordinary enough to justify regulatory tracker treatment.

Q. How do EMM's recent actual or expected future CIP and cybersecurity expenses compare to EMM's total annual expenses or annual revenues?

A. The 2026 O&M nonlabor NFOM Security budget EMM supplied in response to OPC DR 1100 shows a budgeted amount fairly consistent with EMM's historic O&M nonlabor expenses.[7]

[5] EMM's response to OPC DR 1101.
[6] Id.
[7] EMM response to OPC DR 1100.

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Q. At these levels, are EMM's forecasted CIP and cybersecurity expenses substantial enough to have a material effect upon revenue requirements and EMM's financial performance between rate cases?

A. No. Given the moderate amount of historical and forecasted expenses, as a percentage of overall revenues and costs, considering these costs in isolation do not reasonably or adversely impact EMM's future financial stability or access to capital.

Q. Are EMM's CIP and cybersecurity costs beyond the control of its management?

A. Not entirely. While many costs associated with following its obligation to comply with Federal and State regulations is beyond utility control, management still has responsibility and control relating to hiring, training, and testing decisions. Additionally, utility management decides on security modifications and capital investments related to achieving and maintaining compliance. Therefore, approving a full recovery expense tracker encompassing future incrementally incurred CIP and cybersecurity compliance expenses, that the Company determines, is not reasonable. Such a tracker would eradicate management incentives to achieve compliance through the implementation of cost-effective solutions.

Q. Would a cost tracking mechanism for EMM's CIP and cybersecurity costs be readily verifiable through expedited regulatory audit, reviews, and straightforward administration?

A. No. EMM has already incurred expenses to control access to Company-wide business information systems and maintain security within its facilities. These expenses encompass labor and non-labor costs, in addition to capital investments. Given the relationship between systems already in place, there are no clear lines of differentiation to cleanly separate new CIP costs from the historic activities and baseline costs. With the option to utilize a tracking mechanism, utility management would have a financial incentive to designate new spending as somehow connected to CIP or cybersecurity in situations where such costs actually

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encompass systems outside of CIP or cybersecurity. An example is the maintenance or upgrade of a major information technology system. Only a portion of maintenance or upgrading should be classified as security-related to qualify for tracker recovery. However, if a cost recovery mechanism is available, a subjectively larger amount may be classified as security-related even if that's not the case. Such is an underlying challenge with any regulatory tracking mechanism. Includable costs should be clearly defined using administratively defined criteria which are easily applied, quantifiable and verifiable.

FUEL ADJUSTMENT CLAUSE AND ADDITIONAL TARIFF CLARIFICATIONS

Q. Are FACs governed by Missouri Commission adopted rules?

A. Yes. The Commission has adopted 20 CSR 4240-20.090 Fuel and Purchase Power Rate Adjustment Mechanisms to set forth the definition, structure, operation, and procedures relevant to the filing and processing of applications to reflect prudently incurred fuel and purchased power costs through a fuel adjustment clause. Section 386.266, RSMo, is the state statute that controls these mechanisms.

Q. When did the Commission first entertain a statutory FAC request?

A. In Ameren Case number ER-2007-0002, the Commission first considered such a FAC request. The Commission made the following statements regarding FACs:

> A fuel adjustment clause should be used cautiously because it runs contrary to some of the basic principles of traditional utility regulation. One such principle is the matching of expenses and revenues.
>
> Inclusion of a fuel adjustment clause also affects the operation of regulatory lag…Since a rate case takes eleven months to complete, a utility will always be about eleven months behind. Of course, utilities do not particularly like regulatory lag when their costs are increasing, but regulatory lag can also favor the utility when their costs are decreasing. The good effect of regulatory lag is that it provides the utility with a strong incentive to maximize its income and minimize its costs. If, however, a fuel adjustment

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> clause is in place, the utility has less financial incentive to minimize its fuel costs because those costs will be automatically recovered from ratepayers. Based on the previous paragraphs, it might seem that a fuel adjustment clause should never be inflicted upon ratepayers. But there might be circumstances when the use of a fuel adjustment clause may be necessary to preserve the financial health of the utility, and no one, including ratepayers, benefits when a utility becomes financially unhealthy. In an era where fuel costs are highly volatile, a fuel adjustment clause may be necessary if the company is to earn its authorized rate of return. The problem then is how to determine when a fuel adjustment clause is necessary.[8]

In addition to these comments, the Commission also found that a FAC request should be considered in relation to three criteria:

1. Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases;
2. Beyond the control of management, where utility management has little influence over experienced revenue or cost levels; and
3. Volatile in amount, causing significant swings in income and cash flows if not tracked.[9]

Q. Did the Commission give additional clarity in its Report and Order for applying the criteria listed above?

A. Yes. The Commission also stated that "volatile prices tend to go up and down in an unpredictable manner", rather than simply including increased costs.

> Thus AmerenUE's fuel costs, while certainly rising, cannot be said to be volatile. Markets in which prices are volatile tend to go up and down in an unpredictable manner. When a utility's fuel and purchased power costs are

[8] *Report and Order,* pp. 17-19, In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area, Case No. ER-2007-0002, EFIS Item No. 905 (May 22, 2007).
[9] Id. at pp. 20-21.

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> swinging in that way, the time consuming ratemaking process cannot possibly keep up with the swings. As a result, in those circumstances, a fuel adjustment clause may be needed to protect both the utility and its ratepayers from inappropriately low or high rates. Because AmerenUE's costs are simply rising, that sort of protection is not needed.[10]

Q. When did the Commission first authorize EMM to use a FAC?

A. When the Commission authorized Kansas City Power & Light Company, to use a FAC in Case No. ER-2014-0370.

Q. Did the Commission use the same three criteria in that case as it did in Ameren's rate case?

A. Yes. While wording them differently, similar to its criteria in the ER-2007-0002 case, in its Finding of Facts in its Report and Order in Case No. ER-2014-0370, the Commission referred to the following criteria:

1. They represent a significant portion of a utility's costs;
2. they fluctuate significantly; and
3. the costs are outside the utility's control.[11]

Q. Does EMM currently recover SPP administrative fees through its FAC?

A. No. SPP administrative fees are not currently recoverable through EMM's FAC.

Q. Should they be?

A. No. SPP administrative costs are not extraordinary or volatile, are not fuel and purchased-power costs, including transportation, and do not meet the standard cost tracking mechanism criteria. In Case No. ER-2014-0370, In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electrical Service, the Commission stated the following in its *Report and Order:*

[10] Id. at p. 23.
[11] Id.at p. 34.

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> KCPL has requested that SPP Schedule 1-A and 12 fees be included in its FAC. The Commission finds that these fees are administrative in nature and not directly linked to fuel and purchased power costs. These fees support the operation of SPP and are not needed for KCPL to buy and sell energy to meet the needs of its customers. These fees are neither fuel and purchased power expenses nor transportation expenses incurred to deliver fuel or purchased power. The Commission concludes that including such fees would be unlawful under Section 386.266.1, RSMo, and, therefore, Schedule 1-A and 12 fees should not be included in the FAC. These fees are appropriate for recovery in base rates.[12]

Q. Should long-term capacity contract costs flow through EMM's FAC?

A. No.

Q. Why not?

A. Traditionally, from what I have found, long-term capacity contracts last over one year, are not particularly variable, and are usually under the company's control. For these reasons, long-term capacity contracts are recovered in base rates as a cost of doing business.

Q. Are there additional reasons long-term capacity contracts should not be included for recovery through a FAC?

A. Yes. Capacity contracts ensure that a generator is ***available*** to produce electricity to meet peak demand, thereby ensuring sufficient supply. According to FERC's guidance in understanding wholesale capacity markets, a capacity market **does not pay for the energy produced** but instead **pays for the ability to produce power when needed[13].** This equates to a demand charge for a generator to be on standby in case the grid needs more generation to

[12] *Report and Order*, p. 36, In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service, Case No. ER-2014-0370, EFIS Item No. 592 (Sept. 2, 2015).
[13] https://www.ferc.gov/understanding-wholesale-capacity-markets; Schedule ADS-D-3.

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meet demand, not for prudently incurred fuel and purchased-power costs, including transportation costs for the generation of energy.

Q. Is there testimony from any prior cases that addresses the recovery of capacity contracts through the FAC?

A. Yes. In ER-2007-0004, Staff witness Cary Featherstone opined the following:

> Regardless of the type of recovery mechanism the Commission authorizes in this case, Staff believes the demand charge component of capacity agreements should not be included in the fuel recovery process. Demand charges are fixed costs to reserve capacity of another company's production facilities. These fixed costs are more like plant investment costs and should not be included in any fuel recovery mechanism. The more recent IEC's[14] have not included any fixed fuel or purchased power costs and Staff continues to believe these costs are not what typical fuel recovery mechanisms are intended to collect. Staff believes these mechanisms are intended to recover variable fuel and purchased power costs that have been shown to be difficult to forecast for ratemaking purposes. Staff would recommend not including demand charges for capacity agreements of less than one year duration for the same reasons as those agreements that are greater than one year.[15]

Q. Has the Commission opined on the recovery of capacity contract costs through a FAC elsewhere?

A. Yes. In Case No. ER-2007-0004, In the Matter of Aquila, Inc.'s Request for Authority to File Tariffs Increasing Electric Rates for the Service provided to Customers, the Commission stated the following in its *Report and Order*.

[14] Interim Energy Charge - a form of cost recovery mechanism used in the past.
[15] *Exhibit No. 207 - Rebuttal testimony of Cary G. Featherstone*, p. 8, In the Matter of Aquila, Inc. d/b/a Aquila Networks-MPS and Aquila Networks-L&P, for Authority to File Tariffs Increasing Electric Rates for the Service provided to Customers in the Aquila Networks-MPS and Aquila Networks-L&P Service Area, Case No. ER-2007-0004.

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Staff witness Cary Featherstone argues only variable fuel and purchased power costs, including variable transportation costs, should be included in a fuel adjustment clause. Specifically, Mr. Featherstone contends it is inappropriate to include demand charges for any capacity contracts, regardless of their duration, for two reasons. First, Mr. Featherstone points to the fact that demand charges are fixed costs to reserve capacity, and as such are more like plant investment cost than fuel or purchased power cost. Second, Staff opposes Aquila's use of short-term contracts to meet its growing capacity needs. Staff argues that allowing Aquila to pass on this type of cost would allow Aquila to meet its growing load requirements through short-term capacity, thus creating another disincentive for it to build generating units and placing all the risk of future fuel and purchased power cost increases on its customers. Mr. Featherstone's analysis is persuasive.

Findings of Fact: The Commission finds a reasonable fuel adjustment clause should be straightforward and simple to administer, retain some incentive for company efficiency, and be readily auditable and verifiable through expedited regulatory review. The Commission can find no probative evidence in the record to support a finding that hedging costs or demand charges related to purchased power contracts with terms of one year or less should be recovered in a different manner than purchased power contracts with longer terms. The Commission agrees with Staff, and finds that demand charges are fixed costs to reserve capacity, and as such are more like plant investment cost than fuel or purchased power cost. This is the case irrespective of the length of the purchased power contract. Further, if demand charges on short term contracts are allowed to flow through the fuel adjustment clause, Aquila would be encouraged to forgo entering long term contracts in favor of short term contracts.

Conclusions of Law: The Commission concludes it would be improper to allow Aquila to flow hedging costs or demand costs associated with any purchased power contract through its fuel adjustment clause. The Commission concludes Aquila will only be

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allowed to flow variable fuel and purchased power costs, including variable transportation costs, through its fuel adjustment clause.[16]

Q. Based on the Commission's decision in Case No. ER-2007-0004, should the costs of any capacity contracts – both long and short term – be recovered through a FAC?

A. No.

Q. Does EMM currently have long-term capacity contract costs it intends to flow through its FAC?

A. Not that I have found. Based on the record in this case, there are no current long-term capacity contracts for which EMM has requested recovery through its FAC.[17] Therefore, there is no reason to include language in EMM's FAC tariff to pass through long-term capacity contract costs.

Q. Is there any reason why EMM may require more long-term capacity?

A. Yes.

Q. What reason?

A. Evergy is experiencing growth in Large Load Power Service ("LLPS") customers. Until EMM builds and places in service, or otherwise acquires additional generating resources, interim long-term capacity agreements are needed to provide the necessary capacity to serve native load.

[16] *Report and Order*, pp. 43-44, Case No. File No. ER-2007-0004, EFIS Item No. 363 (May 17, 2007).
[17] Linda Nunn FAC base factor calculation workpaper, Case No ER-2026-0143.

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Q. Do LLPS customers have the option to bring their own capacity?

A. It appears so. According to notice on March 20, 2024, Google announced a purchase power agreement with Ranger Power and DESRI[18] for energy capacity from the Beavertail Solar farm, located in Henry County, Missouri.[19]

Q. If LLPS customers have the ability and resources to bring their own capacity in order to assist in satisfying their load, should these capacity contract costs flow through the FAC of the utility that supplies their electric service?

A. No. In order to adhere to the protections outlined in the *Stipulation and Agreement* and the Commission's *Report and Order* in File No. EO-2025-0154, capacity contracted by and for LLPS customers should not be included in EMM's, or EMW's, FAC. According to the *Report and Order*, several features included within the Stipulation and Agreement, of which includes contract capacity, "will make the LLPS class self-sustaining."[20]

Q. In Case No. EO-2025-0154 did OPC or Staff witnesses testify regarding how the fuel costs to serve LLPS customers should be treated in EMM's and Evergy Missouri West's ("EMW's") FACs?

A. Yes. Both OPC witness Lena Mantle and Staff witness Sara Lange testified that the fuel costs EMM and EMW would incur for their LLPS customers would be subsidized by their other customers through their FACs. Ms. Mantle testified that if the fuel costs for all customers are included within one FAC, then during the next rate case after adding a LLPS customer, the "amount of fuel [costs] included in the base rates for the non-LLPS customers will increase as will the FAC base factor. Non-LLPS customers will continue to subsidize LLPS customers through the FAC since the increased FAC costs will be charged all customers[21]." The same

[18] D.E. Shaw Renewable Investments
[19] https://rangerpower.com/wp-content/uploads/2024/03/2024GoogleKCAnnouncement.pdf ; Schedule ADS-D-4.
[20] *Report and Order*, p. 26, In the Matter of the Application of Evergy Metro, Inc. d/b/a Evergy Missouri Metro and Evergy Missouri West, Inc. d/b/a Evergy Missouri West for Approval of New and Modified Tariffs for Service to Large Load Customers, Case No. EO-2025-0154, EFIS Item No. 210 (Nov. 13, 2025).
[21] *Exhibit No 300 - Surrebuttal Testimony of Lena Mantle*, p. 2, Case No. EO-2025-0154.

can be said for capacity costs. If LLPS capacity costs are included in the FAC base factor calculation, then non-LLPS customers will end up subsidizing LLPS customer capacity costs. A FAC base factor calculation including both LLPS and non-LLPS customers "would result in all customers being charged more for fuel and purchased power costs in their base rates and the FAC,[22]" even though non-LLPS average fuel and purchased power costs would be lower without the inclusion of LLPS customer load costs.[23]

Q. Do you agree with them?

A. Yes.

Q. Is excluding the fuel costs of LLPS customers from the FAC the only way to avoid having non-LLPS customers subsidize the fuel costs of LLPS customers?

A. No. One way to avoid cross-subsidization with a FAC would be to create essentially an additional, LLPS-only FAC, or a LLPS-specific section within the current FAC, with a base factor that is specifically calculated based on the fuel costs of LLPS customers.

Q. Can a FAC be modified between rate cases?

A. No. My understanding is they cannot lawfully change between general rate cases. In its *Report and Order* in Case No. 2025-0154 the Commission stated that "the Commission shall have the power to approve, modify, or reject adjustment mechanisms, such as the FAC, only after providing the opportunity for a full hearing in a general rate proceeding."[24] Further, section 386.266, RSMo, in subsection five, includes the following language: "The commission shall have the power to approve, modify, or reject adjustment mechanisms submitted under subsections 1 to 4 of this section only after providing the opportunity for a full hearing in a general rate proceeding, including a general rate proceeding initiated by complaint."

[22] Id. at p. 3.
[23] Workpaper of Lena Mantle in Case No. EO-2025-0154; Schedule ADS-D-5
[24] *Report and Order*, p. 40, Case No. EO-2025-0154.

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Q. Should the Commission entertain modifications to EMM's FAC in this general rate case?

A. Yes.

Q. What modifications to EMM's FAC are you proposing?

A. I recommend the Commission continue with precedent and not allow SPP purchased power administration fees in the FAC. These costs are not extraordinary or volatile and do not meet the criteria for recovery through a cost tracking mechanism.

Furthermore, to prevent the subsidization of LLPS customer fuel, purchased power, and capacity costs by non-LLPS customers, I recommend that LLPS customers be excluded from EMM's current FAC. Alternatively, if EMM and LLPS customers are of the opinion that both EMM and LLPS customers would benefit from a FAC, I recommend the establishment of a FAC for only LLPS customers. A FAC specifically designated for LLPS customers should ensure that LLPS customers are paying their full cost of service relating to fuel, purchased power, and capacity requirements.

Q. Does this conclude your testimony?

A. Yes.

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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 ANGELA SCHABEN

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Angela Schaben, of lawful age and being first duly sworn, deposes and states:

1. My name is Angela Schaben. I am a Senior Utility Regulatory Auditor for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my direct testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Angela Schaben
Senior Utility Regulatory Auditor

Subscribed and sworn to me this 29th day of June 2026.

TIFFANY HILDEBRAND
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES AUGUST 8, 2027
COLE COUNTY
COMMISSION #15637121

Tiffany Hildebrand
Notary Public

My Commission expires August 8, 2027.