Exhibit No. 306

OPC – Exhibit 306
Angela Schaben
Direct
File No. ER-2024-0189

Exhibit No.:		______________
Issue(s):		Cost Tracking Mechanisms/ Fuel Adjustment Clause
Witness/Type of Exhibit:		Schaben/Direct
Sponsoring Party:		Public Counsel
Case No.:		ER-2024-0189

DIRECT TESTIMONY

OF

ANGELA SCHABEN

Submitted on Behalf of the Office of the Public Counsel

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

CASE NOS. ER-2024-0189

** ________________________________ **
Denotes Confidential Information that has been redacted.

June 27, 2024

PUBLIC

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DIRECT TESTIMONY

OF

ANGELA SCHABEN

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

CASE NO. ER-2024-0189

INTRODUCTION

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

A. Angela Schaben, 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 testified previously before the Missouri Public Service Commission?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony regards Evergy Missouri West ("EMW") 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 various aspects of the relationship between transmission congestion, long-term wind PPA contracts, and alleged alternative revenue streams related to these contracts and transmission congestion.

Q. Please summarize your recommendations as presented in the subsequent testimony.

A. My recommendations to the Commission are summarized as the following:

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.

3. Order improved FAC monthly reporting to include locational market price ("LMP") for each generation source by node and additional clarity in TCR/ARR reporting.

4. Include **__________ ** of actual TCR/ARR revenues, with true-up through June 30, 2024, in revenue requirement and FAC base factor calculation, to appropriately account for transmission congestion revenues.

REGULATORY TRACKERS AND RELATED POLICY CONCERNS

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

A. Expense tracking mechanisms defer costs to future rate cases to ensure increased revenues beyond those available from normal rate case processes.

Q. What trackers have EMW proposed in past cases?

A. The Company has requested various tracking mechanisms prior rate cases, to include, but are not limited to: a property tax tracker, bad debt tracker, cybersecurity tracker, storm reserves tracker, etc. The Company's request for these trackers have primarily resulted from Company perceived effects of regulatory lag.

Q. Of the trackers the Company has requested in the past, have any trackers been granted by the Commission?

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. Since trackers assist in reducing regulatory lag, are there potential repercussions relating to efficient regulatory 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:

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> 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 customer from excessive utility costs by scrutinizing a utility's costs in a rate case, conducting 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 reduce business risk relating to prudent or efficient management practices, the risk and regulatory lag reduction should be factored into return on equity ("ROE") rate.[2]

Q. By what standard should trackers be evaluated in Missouri?

A. 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 deferral accounting typically been allowed by the Commission?

A. The Commission has previously approved deferral accounting, by use of a tracker or an accounting authority order, for costs incurred resulting from (1) an Act of God or (2) new

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[1] NRRI How Should Regulators View Cost Trackers, page 16; Schedule ADS-D-2.
[2] Id. Page 10-11.
[3] File No. EU-2014-0077, *Report and Order*, issued July 30, 2014, page 10.

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legislation or rules. For example, regarding the former, the Commission has allowed deferral accounting for costs the utility incurred in responding to extreme or unprecedented events, such as Storm Uri and COVID. Regarding the latter, the Commission has allowed deferral accounting resulting from certain legislation and rules, including gas pipeline replacement rules and lead water lines replacement rules. In these cases, extraordinary costs not already included in a utility's cost of service, are incurred.

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

A. No. The tracking mechanisms that have been previously requested by EMW 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 subjected to regulatory tracking and 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 these 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. Do tracking mechanisms utilized for specific utility costs impact management incentives to control tracked costs?

A. Yes. Tracking mechanisms initiated for specific costs eliminates management efficiency incentives normally caused by regulatory lag. If every dollar of tracked cost is eligible for future rate recovery through deferral, there is less incentive for management to aggressively pursue cost containment for such costs, only to focus on other business areas where earnings are impact by cost containment. 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. Does the implementation of cost tracking mechanisms add to the Commission's resource commitments and regulatory responsibilities?

A. Yes. Through creation of cost deferral accounting entries and carrying charges requiring thorough analyzation for accuracy and prudence, each cost tracking mechanism imposes additional regulatory burdens upon the Commission, its Staff, and intervenors. However, regulatory resources required for such critical analysis is often limited even as regulatory burdens increase.

Q. Are there additional criteria regulatory Commissions have utilized in evaluating the necessity for tracking mechanism treatment of specific utility costs, in addition to unusual extraordinary costs that occur infrequently?

A. Yes. 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 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:

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1. Significant enough to cause a material impact upon revenue requirements and business financial performance between rate cases.
2. Causing volatile and significant swings in income and cash flows.
3. Utility management has little control or influence over cost or revenue levels.
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. Has EMW incurred historical costs to ensure physical and system security at its critical facilities?

A. Yes. Table 1 below shows the consistency between EMW cybersecurity O&M expenses from 2018 through 2023, even a reduction in 2023[4]:

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

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

[4] EMW response to Staff DR 0272.

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Committee Board meeting minutes, repeatedly provides quarterly IT Scorecard, Cybersecurity Capability Maturity Model (C2M2) Assessment, and recent GridEx participation updates. Evergy's Cybersecurity/IT Committee repeatedly reports that Evergy cybersecurity measures score higher than **______ ** with a score in the **___ **.

Q. Does the Company have an opportunity to recover O&M and capital costs related to recently expanded 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 EMW supplied estimated future compliance costs for CIP and cybersecurity?

A. EMW provided a 2024 O&M Nonlabor NFOM Security budget in the amount of **_________**, which is consistent with spending in prior years. As of 03/28/2024, 2025-2028 projections were unavailable[5]. Projections illustrate why a CIP/ cybersecurity tracking mechanism is inappropriate. Forecasted non-labor O&M expenses are not volatile, large, or such that justifies extraordinary regulatory tracker treatment.

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

A. The 2024 O&M nonlabor NFOM Security budget EMW supplied in response to Staff DR 0273 shows a budgeted amount consistent with historic O&M nonlabor expenses.

[5] EMW's response to Staff DR 0273.

Q. At these levels, are EMW's forecasted CIP and cybersecurity expenses substantial enough to have a material effect upon revenue requirements and the Company'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 EMW's future financial stability or reasonable access to capital.

Q. Are EMW's CIP and cybersecurity costs beyond the control of Company management?

A. Not entirely. While the 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. Approving a full recovery expense tracker encompassing future incrementally incurred CIP and cybersecurity compliance expenses, as determined by the Company, 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 EMW's CIP and cybersecurity costs be readily verifiable through expedited regulatory audit, reviews, and straightforward administration?

A. No. EMW 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 costs baseline. 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 beyond just CIP or cybersecurity. An example is the maintenance or upgrade of a major information technology system. Only a portion of maintenance or upgrading could 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 the underlying challenge with any regulatory tracking mechanism. Includable costs should be clearly defined using administratively defined criteria which is easily applied and verified.

<u>INJURIES AND DAMAGES TRACKING MECHANISM</u>

Q. What are the historic injuries and damages expenses EMW provided during discovery of this rate case and ER-2022-0129/0130?

A. EMW provided a summary of injuries and damages expenses for the past three years as shown in Table 2[6]:

EMW Injuries and damages ("I&D") Expenses – Table 2

Year	Expense Summary
2021	$ 2,688,363.32
2022	$ 2,379,883.97
2023	$ 2,102,849.61

Q. Based on the historic I&D expenses provided in Table 2, is an Injuries and Damages reserve warranted?

A. No. EMW's I&D expenses from 2021 through 2023 have not increased, do not appear extraordinary or volatile and therefore do not require the need for a cost tracking mechanism. In fact, years 2021 through 2023 show a decrease.

[6] EMW response to Staff Data request 0099 in File No. ER-2022-0129/0130 and ER-2024-0189.

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Q. What is your recommendation to the Commission?

A. EMW's historic cybersecurity O&M and I&D expenses shows these as reoccurring costs incurred through the course of regular business operations that are not volatile or extraordinary and will eventually be addressed in a rate case. Attempting to isolate and track these selected costs, while simultaneously overlooking utility continuous changes in a utility's revenue requirement that may otherwise offset these costs could lead to excessive and unfair rates. For this reason, the Commission should not approve cost tracking mechanisms for incremental cybersecurity and I&D expenses.

<u>FUEL ADJUSTMENT CLAUSE AND ADDITIONAL TARIFF CLARIFICATIONS</u>

Q. Is the Fuel Adjustment Clause 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.

Q. When did the Commission first consider a fuel adjustment request?

A. In Ameren Case number ER-2007-0002, the Commission first considered a fuel adjustment clause request. The Commission made the following statements regarding fuel adjustment clauses:

> 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

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> adjustment 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.[7]

In addition to these comments, the Commission also found that a fuel adjustment clause 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.[8]

Q. Did the Commission's Report and Order provide additional clarity in its application of 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.

[7] Report and Order, May 22, 2007, Union Electric Company d/b/a Ameren Missouri, Case No. ER-2007-0002, pages 17-19.
[8] Id. Pages 20-21.

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> 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 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.[9]

Q. When was EMW first approved for a FAC?

A. The Commission first approved an FAC for EMW's predecessor company, Aquila Inc., in its ER-2007-0004 rate case.

Q. In the ER-2007-0004 Report and Order, did the Commission utilize the similar criteria as ER-2007-0002 in its opinion?

A. Yes. Similar to the ER-2007-0002 case, in its <u>Finding of Facts</u> in its Report and Order in ER-2007-0004, the Commission agreed with AARP witness Nancy Brockway[10] that an FAC should only be used for costs that meet 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. Have there been any significant changes between the first inception of EMW's FAC to current day?

A. Yes. While several changes have occurred, I will discuss only a few. When EMW first implemented a FAC, the SPP energy market did not exist. At that time, the Company supplied more energy from owned generation and long-term PPAs tied to thermal generating units than

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[9] Id. Page 23.
[10] Report and Order, May 17, 2007, Aquila, Inc., d/b/a Aquila Networks – MPS and Aquila Networks, Case No. ER-2007-0002, Page 37.
[11] *Id.*, page 34.

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it currently does. Also different is the overall fuel mix, partially resulting from inclusion of wind PPAs in the current FAC, as compared to 2007, and the retirement of EMW's only solely owned Sibley coal facility.

Q. Are there additional financial instruments primarily related to the newer wind PPAs currently included in the FAC?

A. Yes. EMW flows Transmission Congestion Rights ("TCRs") and Auction Revenue Rights ("ARRs") revenues related to wind PPAs through the FAC.

Q. What are TCRs and ARRs?

A. According to SPP's glossary, an ARR is a financial right, awarded during the Annual ARR Allocation Process that entitles the holder to a share of the auction revenues generated in the applicable TCR Auction(s) and/or entitles the holder to self-convert the ARRs to TCRs. A TCR is a financial right entitling the holder to a share of the congestion revenue collected in the Day-Ahead Market.[12]

Q. Has the concept of TCR/ARR revenue streams correlating to long term wind PPA contracts been a major issue in past cases?

A. The first time that the concept of TCR/ARR revenues and their use to offset congestion common with wind generation source/sink nodes became a major issue in a case was in the surrebuttal testimony of Evergy witness Kayla Messamore in case nos. EO-2023-0276/0277 on January 18, 2024. Ms. Messamore's testimony provides information relating to alternative revenue streams generated by long-term wind PPA contracts that Staff "failed to take into account" with its disallowance.

[12] https://www.spp.org/glossary/

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Q. Why did Staff fail to take TCR/ARR revenue streams into account during EO-2023-0276/0277?

A. I cannot speak for Staff, but from my understanding of that particular case, the Company waited until surrebuttal to introduce the benefits of TCR/ARR revenue offsetting congestion costs related to long term wind PPA contracts, even though Staff proposed a disallowance for wind PPA losses in its Prudence report.

Q. Did Staff voice concern regarding purchased power wind contracts prior to EO-2023-0276/0277?

A. Yes. Staff did voice several concerns regarding the Company's PPAs in its EO-2020-0280/0281 Staff report. Notably, Staff states the following on page two of its report:

> The Companies have failed to meet the fundamental objective of the 18 Commission's Chapter 22 Rules by entering into ** ___ ** MW of fixed price wind power purchase agreements (PPAs) based upon speculation of future SPP energy prices. Entering into a PPA based on speculated market revenues that could outweigh costs does not serve the public interest because flowing all of the costs of these PPAs through the Companies' fuel adjustment clauses creates a potentially large amount of risk to ratepayers and almost zero risk to shareholders at a point in time when the SPP Market Monitoring Unit states that "market prices have not been signaling new generation entry for some time." The Companies do not need to enter into the PPAs for SPP resource adequacy requirements, reliability needs, or Missouri Renewable Energy Standard requirements. The Companies state in the Annual Reports that the PPAs were entered into in part for the Renewable Energy Rider, however Staff cannot determine the accuracy of that statement at this time. Furthermore the economic feasibility analysis that was relied upon for the contracts blatantly ignore realities of the SPP markets, utilizes stale market price forecasts that are limited to only six

> potential outcomes, relies on developer estimates that are much greater than the actual outputs of the existing Evergy Metro and Evergy West PPAs, ** ____ ____ ____________________ **

Staff's concerns continue into page three of its EO-2020-0281/0281 report:

> ... The Companies did not need to enter into the PPAs to meet SPP resource adequacy needs, reliability needs, or Missouri RES compliance requirements. Since the Companies will be purchasing the energy generated by a third party, the Companies will not own, operate, control or manage the facilities. Further, the Companies' shareholders will not finance the purchase. Rather ratepayers will be required to finance the purchase for 15+ years through collection of costs through fuel adjustment clauses of the Companies… In the case of the wind PPAs entered into by the Companies, they are not in the public interest for several reasons. The PPAs are not needed, the economic analysis relied upon is extremely flawed, and nearly all of the risk is borne by ratepayers. Staff requested for the Companies to demonstrate the need for the wind PPA additions in 2021 and 2022 in the preferred resource plans.[14] The Companies' response to this request simply referred to the Companies' December 16, 2019 Notice of Determination of Change in Case Nos. EO-2018-0268 and EO-2018-0269, in which the Companies notified the Commission that a decision had been made to enter into two PPAs totaling ** ___ ** MW that would be allocated to Evergy Missouri Metro and Evergy Missouri West. Staff requested supplemental responses to this data request that actually demonstrated the need to enter

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[13] The footnote attached to this portion is for Company response to Staff Data Request No. 0033 in EO-2020-0280 and EO-2020-0281.

[14] The footnote attached to this portion is for Company response to Staff Data Request No. 0001 in EO-2022-0280 and EO-2020-0281.

> into the wind PPAs, to which the Companies continuously insisted that the original response was adequate. The notion that simply making a decision to enter into wind PPAs is an adequate demonstration of the need for the contracts is not only concerning, but insufficient. By that logic, the Companies could continually add the costs of an unlimited number of PPA contracts to Evergy West's and Evergy Metro's respective fuel adjustment clauses without any demonstration of a need to do so. In fact, the Companies' response to Staff data request 0023 indicates that the Companies do not have an upper limit on the number of wind PPAs the Companies would consider entering into based on the capacity positions and customer loads of Evergy Metro and Evergy West. The Commission's regulatory oversight of the decision making of Evergy Metro and Evergy West would be significantly hindered by actions such as these… However, by entering into contracts for a large number of PPAs without demonstrating the need, relying upon speculated revenues outweighing expected costs, and not providing sound economic analysis at the time of entering the PPAs, the Companies have shifted all of the risk to ratepayers through the fuel adjustment clauses and shifted all of the burden of proof onto other stakeholders by making prudence reviews the process for initial in-depth analysis of the decision to enter into the PPAs.[15]

Furthermore, Staff reiterated its concerns relating to the net losses of wind PPAs passing through the Company's FAC in case no. ER-2022-0129/0130. A Stipulation and Agreement filed on August 30, 2022, which stated the following in paragraph 5, item number 4:

> The Company will exclude from its FACs the net costs associated with wind purchased power agreements ("PPAs") entered into after May 2019 whose costs exceed their revenues resulting in a net loss. Language will be

[15] Staff Report EO-2020-0280/0281.

> included in its FAC tariff sheets reflecting this exclusion. The Company will factor the financial risk of this settlement condition into its evaluation of wind PPAs in its prospective long-term resource planning during such time that the condition is in effect.

Q. So, to clarify, Staff raised these concerns before the Company provided information clarifying the details on its TCR/ARR revenue streams??

A. Correct. Evergy witness Kayla Messamore in EO-2023-0276/0277 delayed in providing clarifying details on TCR/ARR revenue streams that offset net PPA losses on certain contracts until surrebuttal testimony on January 18, 2024. This was 4 ½ months after Staff's report filed on August 30, 2024 found these wind PPAs imprudent.

Q. Since EMW's introduction of TCR/ARR revenue streams offsetting wind PPA losses on January 18, 2024, what have you learned about the SPP TCR/ARR markets?

A. Attached to my testimony as Schedules AS-D-3 and AS-D-4 are documents providing details on TCR/ARR markets, SPP congestion hedging, etc.[16] In its LTCR, ARR & TCR Portfolio Optimization guidelines,[17] EMW states the following:

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[16]; SPP Congestion Hedging FAQ; Schedule ADS-D-3
[17] Evergy LTCR, ARR & TCR Portfolio Optimization received by Evergy in the Stipulation and Agreement in EO-2023-0276/0277; Schedule ADS-D-4.

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Additionally, Southwest Power Pool ("SPP") also provides the following guidance on its website:

> Transmission Congestion Rights ("TCR") Markets provide financial rights that can be used to hedge against the Day-Ahead Market transmission congestion between two settlement locations.
>
> The SPP TCR Markets process uses two forms of rights. First, the TCR is used to distribute the Day-Ahead congestion rents that occur each hour. Second, the Auction Revenue Rights ("ARRs") are used for the distribution of the revenue generated in the auctioning and awarding of TCRs. TCRs are source-to-sink (point-to-point) instruments that are awarded in 01 MW increments.[18]

Q. What is congestion?

A. Congestion is the impedance of electricity flow between generation node and load node. According to the SPP, congestion is "a situation where the desired amount of electricity is unable to flow due to physical limitations (line, bus, storm damages) or regulated limitations, such as contingency reserves. Congestion impairs the ability to use least-cost electricity to meet demand, and a price difference between source and sink."

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[18] https://www.spp.org/engineering/tcr-markets/

Q. What is a node?

A. A node is a specific electrical bus location in the SPP EMS transmission model for which a settlement price is calculated. The generation or source node is where generated energy begins its journey on the transmission network. The load node is the endpoint, where the energy is distributed to the end user/ customer.

Q. What is congestion hedging?

A. A strategy used to reduce the risk of adverse price movements in an asset due to transmission overcrowding.

Q. What is the correct dollar amount related to TCR/AAR revenues to include in the Company's revenue requirement and FAC base factor?

A. The revenue requirement and FAC base calculated in this case should include the 2023 actual ARR/TCR total revenues in the amount of **__________ ** to be updated with additional ARR/TCR revenues through the June 2024 test year update. Currently, the CS-24, 25, 30, and R-30, 35 Fuel, Purchased Power & OSS ("Fuel, PP, & OSS") Margin adjustment includes a TCR margin amount. This TCR margin amount appears to be the difference between ARR/TCR revenues in FERC account 447 minus congestion charges. Congestion cost is the difference between the load node cost and the generation node price. The goal of TCR revenues is to compensate for congestion costs. Including the difference between ARR/TCR revenues and congestion costs in the Fuel, PP, & OSS Margin adjustment rather than actual ARR/TCR revenues accounts for double congestion costs, which means customers end up paying for congestion twice without receiving the full benefits of TCR revenues. I could not find where TCR margins were not visibly accounted for in the Fuel, PP, & OSS Margin adjustment in the ER-2022-0129/0130 case.

Q. What is the current accounting treatment for recording TCR/ARR transactions?

A. According to current FAC tariff sheets, TCR/ARR transactions could be recorded in account 447 or 555.

Q. What is the difference between these accounts?

A. In the Uniform System of Accounts ("USOA"), account 447 is a revenue account and 555 is an expense account.

Q. How are ARR/TCR revenues accounted for in these accounts?

A. According to EMW FAC monthly reports submitted to the Commission in EFIS, ARR/TCR revenues are included in aggregate totals within the 447 and/or 555 accounts. ARR/TCR revenues/expenses are not currently recorded in designated sub-accounts specifically for ARR/TCR revenues/expenses. There is inconsistency in the reporting of ARR/TCR revenues/expenses. Certain workpapers in this case report ARR/TCR revenues in the 447 account whereas EMW's response to OPC data request 8034.1 indicates that "amounts received from ARRs and TCRs for congestion mitigation to offset the amount charged to account 555 for the cost of power bought to serve load. As such these are recorded to account 555."[19] ARR/TCR revenues and losses should be recorded consistently.

Q. Should ARR/TCR revenues/losses be recorded in 447 and 555 sub-accounts specifically designated for such revenues and/or losses respectively?

A. Yes. Currently, subaccount 447025, named "Sales for Resale ARR-TCR" does exist though monthly FAC reports do not show dollar amounts recorded in this account. I did not find a 555 subaccount for ARR/TCR expenses. I will leave the 555 subaccount creation specifically for ARR/TCR expenses to the discretion of the Company. The Company use of each ARR/TCR designated revenue or expense account would provide consistency and accuracy in reporting.

Q. Why?

A. Staff's disallowance related to long term wind PPA losses in EO-2023-0276/0277 was based on contract losses calculated over historic performance periods. Even after the proposed disallowance and its justification in direct testimony – unaware of the role TCR/ARR

[19] EMW response to OPC DR request 8034.1.

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congestion revenues played in long term PPA value – Evergy did not disclose the cause/effect relationship between wind transmission congestion and TCR/ARR congestion revenues until surrebuttal. The FAC monthly reports submitted by the Company did not provide an overall "big picture" view or reconciliation between actual long-term wind PPA contracts and TCR/ARR congestion revenue or an analysis of Wind PPA loss in relation to TCR revenues gained from congestion at wind source-to-sink points.

Q. What additional information should EMW provide in FAC monthly reports pertaining to long-term PPA contract losses in relation to TCR/ARR revenue offsets?

A. Rather than reporting net TCR/ARR transactions, EMW should include TCR/ARR gains and/or losses by node, for the month. Additionally, EMW should provide the following information, by node for the month, in monthly FAC reports submitted to the Commission:

1. A reconciliation of wind PPA contract costs, corresponding TCR/ARR gains and/or losses, and SPP revenues.
2. Locational Market Pricing ("LMP") pricing for each generating resource and EMW's load node by hour.

Q. What is the locational market price (LMP)?

A. According to SPP documentation, a Locational Market Price ("LMP") is the market-clearing price for energy at a given Price Node equivalent to the marginal cost of serving demand at the Price Node, while meeting SPP Operating Reserve requirements. It is calculated using a Security Constrained Economic Dispatch (SCED) and is the price to provide the least-cost incremental unit of energy at a specific location, while also considering congestion and losses.[20]

[20] Markets & Operations - Southwest Power Pool (spp.org); https://www.spp.org/markets-operations/

Q. Are SPP administrative fees currently a recoverable FAC expense?

A. No. SPP administrative fees are not recoverable through the FAC.[21] Currently, Administration Service fees reported on Schedules 1-A2, 1-A3, and 1-A4 are not allowed, as stated in the EMW FAC Original Sheet No. 127.16.

Q. Are there additional administration charge types that should not be included in the FAC?

A. Yes. The Transmission Congestion Rights Administration Service, Integrated Marketplace Clearing Administration Service, and Integrated Marketplace Facilitation Administration Services charge types should not be added to the FAC tariff sheets?

Q. Should SPP admin costs be included in the FAC?

A. No. Administrative costs are not extraordinary or volatile and do not meet the standard cost tracking mechanism criteria. In 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:*

> 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.[22]

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[21] Direct Testimony of Lisa Starkebaum, File No. EO-2023-0276/0277, page 4.
[22] File No. ER-2014-0370, *Report and Order*, issued September 2, 2015, page 36.

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Q. Are there any new SPP charge types that should be added to the FAC tariff sheets?

A. Yes. Evergy added Day-Ahead Uncertainty Reserve Amount, Day-Ahead Uncertainty Reserve Distribution Amount, Real-Time Uncertainty Reserve Amount, Real-Time Uncertainty Reserve Distribution Amount, Real-Time Uncertainty Reserve Non-Performance Amount, and Real-Time Uncertainty Reserve Non-Performance Distribution Amount.[23]

Q. Do agree with these the addition of these charge types?

A. At this time, yes. The Company filed a notice of adding new charge types to FAC monthly reports in ER-2022-0129/0130.

Q. Should hedging be added to EMW's FAC?

A. No. In his testimony OPC witness John Riley explains why hedging should not be included in EMW's FAC.

Q. Are there any other OPC witness with direct testimony regarding EMW's FAC?

A. OPC witness Lena Mantle sponsors testimony on the subject of Crossroads transmission. Ms. Mantle also sponsors testimony proposing an update to EMW's fuel adjustment mechanism that provides a more equitable sharing of fuel and purchased power costs between ratepayers and shareholders.

Q. What is your recommendation to the Commission regarding modifications to EMW's FAC and current monthly reporting?

A. I recommend the Commission continue with precedent and not allow SPP purchased power administration fees in the FAC as these costs are not extraordinary or volatile and do not meet the criteria for recovery through a cost tracking mechanism. Additionally, since the Company's identification of the relationship between wind PPAs and TCR/ARR revenue in

[23] NOTICE OF ADDING NEW SPP CHARGE TYPES; File No. ER-2022-0129/0130.

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surrebuttal testimony on January 18, 2024, EMW's FAC monthly reporting requirements should be updated to provide the following information:

1. Include locational market pricing by node.
2. Provide TCR/ARR revenues/losses by node – not by net revenues or losses.
3. Provide a reconciliation/ cost benefit analysis between TCR/ARR node revenue and/or losses by each wind PPA.
4. Report TCR/ARR revenues and/or losses in specifically designated TCR/ARR subaccounts within the 555000 expense account and 447000 revenue account respectively.

Furthermore, **__________ ** of 2023 ARR/TCR revenue actuals, to be trued up through the June 30, 2024 test year date, should be accounted for in the revenue requirement and FAC base rather than net TCR margins. The goal of TCR revenues is to compensate for congestion costs. Congestion is the difference between the load node and generation node. Including the difference between ARR/TCR revenues and congestion costs in the Fuel, PP, & OSS Margin adjustment rather than actual ARR/TCR revenues, accounts for double congestion costs, which means customers end up paying for congestion twice without receiving the full benefits of TCR revenues.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Missouri West, Inc. d/b/a	)	
Evergy Missouri West's Request for Authority to	)	Case No. ER-2024-0189
Implement A General Rate Increase for Electric	)	
Service	)	

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 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
Utility Regulatory Auditor

Subscribed and sworn to me this 27th day of June 2024.

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.