Exhibit No.:	
Issue:	Revenue Requirement Model and Schedules; Test Year; Misc. Accounting Adjustments including Pensions and Other Post Employment Benefits, Security Tracker, Storm and I&D Reserves;
Witness:	Ronald A. Klote
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Evergy Missouri Metro
Case No.:	ER-2026-0143
Date Testimony Prepared:	February 6, 2026

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2026-0143

DIRECT TESTIMONY

OF

RONALD A. KLOTE

ON BEHALF OF

EVERGY MISSOURI METRO

Kansas City, Missouri
February 2026

Table of Contents

DIRECT TESTIMONY

OF

RONALD A. KLOTE

Case No. ER-2026-0143

I. INTRODUCTION AND PURPOSE

Q: Please state your name and business address.

A: My name is Ronald A. Klote. My business address is 1200 Main St., Kansas City, Missouri 64105.

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

A: I am employed by Evergy Metro, Inc. I serve as Senior Director – Regulatory Affairs for Evergy Metro, Inc. d/b/a as Evergy Missouri Metro ("EMM" or the "Company")), Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("EMW"), Evergy Metro, Inc. d/b/a Evergy Kansas Metro ("EKM"), and Evergy Kansas Central, Inc. and Evergy South, Inc., collectively d/b/a as Evergy Kansas Central ("EKC") the operating utilities of Evergy, Inc.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of EMM.

Q: What are your responsibilities?

A: My responsibilities include the coordination, preparation and review of financial information and schedules associated with rate case filings, compliance filings and other regulatory filings.

Q: Please describe your education, experience and employment history.

A: In 1992, I received a Bachelor of Science Degree in Accountancy from the University of Missouri-Columbia. In May 2016, I completed my Master of Business Administration

Degree from the University of Missouri – Kansas City. I am a Certified Public Accountant holding a certificate in the State of Missouri. In 1992, I joined Arthur Andersen, LLP holding various positions of increasing responsibilities in the auditing division. I conducted and led various auditing engagements of company financial statements. In 1995, I joined Water District No. 1 of Johnson County as a Senior Accountant. This position involved operational and financial analysis of water operations. In 1998, I joined Overland Consulting, Inc. as a Senior Consultant. This position involved special accounting and auditing projects in the electric, gas, telecommunications and cable industries. In 2002, I joined Aquila, Inc. ("Aquila") holding various positions within the Regulatory department until 2004 when I became Director of Regulatory Accounting Services. This position was primarily responsible for the planning and preparation of all accounting adjustments associated with regulatory filings in the electric jurisdictions. As a result of the acquisition of Aquila by Great Plains Energy Incorporated ("GPE"), I began my employment with Kansas City Power & Light Company ("KCP&L") as Senior Manager, Regulatory Accounting in July 2008. In April 2013, I joined the Regulatory Affairs department as a Senior Manager remaining in charge of Regulatory Accounting responsibilities. In December 2015, I became Director, Regulatory Affairs continuing my Regulatory Accounting responsibilities. In addition, I was responsible for the coordination, preparation and filing of rate cases and rider filings in our electric jurisdictions. In October 2021, I became Senior Director of Regulatory Affairs and I continue in that position today with Evergy.

Q: Have you previously testified in a proceeding before the Missouri Public Service Commission ("MPSC" or "Commission") or before any other utility regulatory agency?

A: Yes, I have testified before the MPSC, Kansas Corporation Commission ("KCC"), California Public Utilities Commission, and the Public Utilities Commission of Colorado.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to:

(i) describe the revenue requirement model and schedules supporting the rate request for EMM Schedules RAK-1 through RAK-6.

(ii) identify the witnesses who support various accounting adjustments listed on the Rate Base and Summary of Adjustments (Schedule RAK-2 and RAK-4 attached to this testimony) and provide support on various accounting adjustments. As discussed in Section V of my Direct Testimony, these include but are not limited to adjustments for various pensions and Other Post Employment Benefits, payroll, and storm reserve request.

(iii) support the following proposed accounting adjustments:

Accounting Category	Adjustments
Rate Base Adjustments	RB-21 CWIP – New Gas Generation
Cost of Service Adjustments	CS-11 Out-of-Period Items CS-50 Payroll CS-51 Incentive CS-53 Payroll Taxes CS-61/RB-61 OPEB (SFAS 106) Expense and Regulatory Asset (Liability) CS-62 SERP CS-65/RB-65 Annualized Pension Expense and Regulatory Asset (Liability) CS-71 Injuries and Damages CS-72 Storm Reserve

II. REVENUE REQUIREMENT MODEL AND SCHEDULES

Q: What is the purpose of Schedules RAK-1 through RAK-3?

A: These schedules represent the key outputs of the Company's revenue requirement model used to support the rate increase that EMM requests in this proceeding. Schedule RAK-1 shows the revenue requirement calculation. Schedule RAK-2 lists the rate base components, along with the sponsoring witnesses. Schedule RAK-3 is the adjusted income statement.

Q: Were the schedules prepared either by you or under your direction?

A: Yes, they were.

Q: Please describe the process the Company used to determine the requested rate increase.

A: We utilized our historical ratemaking preparation process to determine the rate increase request. We used historical test year data from the financial books and records of the Company as the basis for operating revenues, operating expenses and rate base. We then adjusted the historical test year data to reflect: (i) normal levels of revenues and expenses that would have occurred during the test year; (ii) annualizations of certain revenues and expenses; (iii) amortizations of regulatory assets and liabilities; and (iv) known and measurable changes that have been identified since the end of the historical test year. We then allocated the adjusted test year data to arrive at operating revenues, operating expenses, and rate base applicable to the EMM jurisdiction. We subtracted operating expenses from operating revenues to arrive at operating income. We multiplied the net original cost of rate base times the requested rate of return to determine the net operating income requirement. This was compared with the net operating income available to determine the additional net operating income before income taxes that would be needed to achieve the requested rate of return. Additional current income taxes were then added to arrive at the gross revenue requirement. This requested rate increase is the amount necessary for the post-increase calculated rate of return to equal the rate of return proposed by EMM witness Geoff Ley in his Direct Testimony and supported by EMM witness Ann Bulkley in her Direct Testimony. Finally, EMM Witness Melissa Hardesty addresses the Company's proposed treatment of any nuclear production tax credits ("PTC") monetized before the true-up period in this case.

III. TEST YEAR

Q: What historical test year did EMM use in determining rate base and operating income?

A: The revenue requirement schedules are based on a historical test year of the 12 months ending June 30, 2025, with known and measurable changes projected through June 30, 2026. At the true-up date, we plan to true up to actuals as part of the true-up process associated with this rate case proceeding.

Q: Why was this test year selected?

A: The Company used the 12-month period ending June 30, 2025 for the test year in this rate proceeding because that period reflects the most currently available quarterly financial information to provide adequate time to prepare the revenue requirement for this case.

Q: Does test year expense reflect an appropriate allocation of Evergy Metro overhead to Evergy Missouri West ("Evergy Missouri West"), Evergy Kansas Central ("Evergy Kansas Central") and other affiliated companies?

A: Yes, Evergy Metro incurs costs for the benefit of Evergy Missouri West, Evergy Kansas Central and other affiliated companies and these costs are billed out as part of the normal accounting process. Certain projects and operating units are set up to allocate costs among the various affiliated companies based on appropriate cost drivers while others are set up to assign costs directly to the benefiting affiliate.

Q: Does Evergy Missouri West and Evergy Kansas Central incur costs that are allocated to Evergy Metro?

A: Yes, costs are allocated from Evergy Missouri West and Evergy Kansas Central to the Evergy Metro jurisdictions.

Q: Why is a true-up period needed for this rate case?

A: Historically, rate cases have included true-up periods which provide for updates to test year data. This process allows for changes in cost levels included in the test year to be updated to the most current information as of a specified date which is closer to the date rates are to become effective. This allows for a proper matching of rate base, revenues and expenses to account for known and measurable changes that have occurred since the end of the test year. As stated above, the Company is requesting a true-up date effective June 30, 2026 in order to provide this update to rate base, revenues and expenses in this rate case.

IV. JURISDICTIONAL ALLOCATIONS

Q: Why is it necessary to allocate revenues, expenses and rate base to the Company's various jurisdictions?

A: Evergy Metro does not have separate operating systems for its Missouri, Kansas, and firm wholesale jurisdictions. It operates a single production and transmission system that is used to provide service to retail customers in Missouri and Kansas, as well as the full-requirements firm wholesale customers. Therefore, jurisdictional allocations of operating expenses, certain operating revenues and rate base are necessary.

Q: Why is the method by which the allocations are made critical?

A: The method of allocation is critical to ensure that the rates charged to each jurisdiction of customers reflect the full cost of serving those customers but not the cost of serving customers in other jurisdictions. In addition, and very important, the method of allocation must allow the Company the opportunity to recover fully its prudently incurred costs of serving those customers. That is, if the sum of the allocation factors allowed in each jurisdiction is less than 100%, then the Company is unable to recover its prudently incurred cost of service and return on rate base.

Q: What allocators did the Company use?

A: The allocators that were utilized can be classified as primary allocators and derived allocators. The primary allocators are based on weather-normalized demand and energy, described in the Direct Testimony of EMM witnesses Albert R. Bass, Jr. and John Wolfram. Attached as Schedule RAK-5 is a listing of the allocation factors for this rate proceeding. The derived allocators are, at their root, based on the demand, energy, and customer allocators. The derived allocators are calculated as a combination of amounts that have previously been allocated using one or more of the primary allocators.

Q: Please describe the demand allocator.

A: The demand allocator being proposed in this case is described in the Direct Testimony of EMM witness John Wolfram. He discusses how demand allocators have been addressed in previous rate filings in Missouri and Kansas. He also discusses how the utilization of different demand allocators often result in inappropriate recovery for a multi-jurisdictional utility such as Evergy Metro.

Q: What is the goal of Evergy with respect to the demand allocator in this case?

A: The Company's goal with respect to the demand allocator is to secure approval by both the MPSC and the KCC of a single, comprehensive determination of the jurisdictional demand allocator to be consistently applied in both the retail jurisdictions of Evergy Metro. For decades, Kansas has used a 12 CP demand allocator in EKM's rate cases while Missouri has used a 4 CP demand allocator in EMM's rate cases. Importantly, EKM's 2023 Kansas rate case reached a unanimous settlement agreement that was approved by the KCC which recognized the importance of finding agreement between the states on how to allocate costs.

Q: How did the unanimous settlement agreement address the demand allocator in EKM's 2023 Kansas rate case?

A: The parties to EKM's 2023 Kansas rate case agreed "for the purposes of allocating capacity-related generation and transmission plant costs between Missouri and Kansas jurisdictions, an average of 4 CP and 12 CP demand allocators should be applied for everything except for Wolf Creek and transmission, which will be based on a 12 CP demand allocator." Additionally, "the parties agreed that the above-described allocator methodology is intended to facilitate a collaborative process with Missouri to attempt to arrive at an agreeable jurisdiction allocator methodology for Kansas and Missouri."

Q: How has collaboration to find an agreeable solution continued since the 2023 Kansas rate case?

A: Evergy Metro, Missouri PSC Staff and KCC Staff as well as other parties to the Companies' jurisdictional rate cases met in June 2023 and in November 2025 Evergy Metro, Missouri PSC Staff and KCC Staff met to advance the dialogue with the parties. The meetings were effective in informing parties of each other's understanding of the issue. The issue is continuing to be advanced in this docket and the Company anticipates additional meetings with parties to find an agreeable solution.

Q: What demand allocation methodology is utilized in developing the Company's revenue requirement in this rate case?

A: As more fully described in John Wolfram's testimony, the Company used an arithmetic average of the values derived from the 4 CP method (the method used historically in Missouri) and the 12 CP method (the method used historically in Kansas) for Steam, Nuclear and Other Production. The 12 CP method was used for Transmission which aligns with how SPP allocates costs and how the KCC recently allocated transmission costs.

Q: Please describe the energy allocator.

A: The energy allocator is based on the total weather-normalized kilowatt-hour usage by the Missouri and Kansas retail customers and the firm wholesale jurisdictional customers which covered the test period July 2024 to June 2025 with customer growth through June 2026. These amounts are supported by Company witness Bass's Testimony.

Q: Please describe the customer allocator.

A: The customer allocator is based on the average number of customers in Missouri, Kansas, and the firm wholesale jurisdiction which covered the test period July 2024 to June 2025 with customer growth through June 2026. Customer growth estimates are supported in the Bass Testimony.

Q: Is the customer allocator determined in a manner consistent with the most recent company rate filing with the commission.

A: Generally, yes. However, the Bass Testimony discusses improvements to the weather normalization process.

Q: Please explain how the various revenue, expense and rate base components are allocated among Evergy Metro's regulatory jurisdictions.

A: Attached as Schedule RAK-6 is a narrative describing the allocation methodology used throughout the components of the revenue requirement model.

Q: Is there anything else related to jurisdictional allocators that you would like to discuss in your direct testimony?

A: Yes. The Company projects additional revenue from new large load power service ("LLPS") customers in EMM's territory over the next several months which it included in adjustment R-20. When computing jurisdictional allocators in its revenue requirement, the Company included an estimate of the impact from these new LLPS customers. It is important that projected revenue and projected demand remain aligned. If projected revenues from this customer were to be adjusted, a corresponding adjustment to projected demand would also be necessary to maintain consistency between revenue and jurisdictional allocators. This alignment preserves the integrity of the cost allocation process.

V. ACCOUNTING ADJUSTMENTS

Q: Please discuss Schedule RAK-4.

A: This schedule presents a listing of adjustments to net operating income for the 12 months ended June 30, 2025, along with the sponsoring Company witnesses. Various Company witnesses will support, in their direct testimonies, the need for each of these adjustments.

Q: Please explain the adjustments to reflect normal levels of revenues and expenses.

A: Adjustments are made to reflect "normal" levels of revenues and expenses; for example, retail revenues are adjusted to reflect revenue levels that would have occurred if the weather had been "normal" during the test year.

Q: Please explain the adjustments to annualize certain revenues and expenses.

A: Revenues are annualized to reflect anticipated customer growth during the true-up period. Annualization adjustments have been made to reflect an annual level of expense in cost of service, such as the annualization of payroll and depreciation expenses. The former reflects a full year's impact of recent and expected pay increases, while the latter reflects the impact of a full year's depreciation on plant additions included in rate base.

Q: Please explain the adjustments to amortize regulatory assets and liabilities.

A: Various regulatory assets and liabilities have been established in past EMM rate cases. These assets/liabilities are then amortized over the number of years authorized in the orders for the applicable rate cases. Adjustments are sometimes necessary to annualize the amortization amount included in the test year or remove amortizations that have ceased during the test year.

Q: Did the Company comply with the prospective tracking of regulatory assets and liabilities as agreed to in the Stipulation and Agreement in Case No. ER-2022-0129 ("2022 Case")?

A: Yes, in this rate case filing, EMM complied with this agreement and reflected the prospective tracking treatment of regulatory assets and liabilities in accordance with this agreement. Please see the individual regulatory asset and regulatory liability adjustments that describe the prospective treatment where applicable in the Direct Testimony of Company witness Darcie G. Kramer and in the testimony of the other Company witnesses sponsoring those adjustments.

Q: Please explain the adjustments to reflect known and measurable changes that have been identified since the end of the historical test year.

A: These adjustments are made to reflect changes in the level of revenue, expense, rate base and cost of capital that either have occurred or are expected to occur prior to the true-up date in this case. For example, payroll expense and fuel costs have been adjusted for known and measurable changes through June 30, 2026.

Q: Do the adjustments listed on Schedule RAK-4 and discussed throughout the remainder of this testimony and other EMM witnesses' testimony entail an adjustment of test year amounts?

A: Yes, the adjustments summarized on Schedule RAK-4 and discussed in this testimony and other EMM witnesses' testimony reflect adjustments to the test year ended June 30, 2025.

RB-21 CWIP – NEW GAS GENERATION

Q: Please explain adjustment RB-21.

A: Adjustment RB-21 reflects the inclusion in rate base of projected construction work in progress ("CWIP") associated with new natural-gas-fired generating facilities that EMM is developing pursuant to the authority granted under Missouri law.

As amended by Senate Bill 4, Section 393.135, RSMo, permits an electrical corporation, subject to specified limitations, to include CWIP for a new natural gas-fired generating unit in rate base during construction. Specifically, the statute provides that:

> An electrical corporation may be permitted, subject to the limitations in this subsection, to include construction work in progress for any new natural gas-generating unit in rate base. The inclusion of construction work in progress allowed under this subsection shall be in lieu of any otherwise applicable allowance for funds used during construction that would have accrued from and after the effective date of new base rates that reflect inclusion of the construction work in progress in rate base.

Consistent with this statutory authority, Adjustment RB-21 includes qualifying CWIP associated with new natural gas generation in EMM's rate base.

Q: What natural gas generation asset is this CWIP request tied to?

A: The CWIP included in Adjustment RB-21 is associated with a new natural gas-fired generating facility that Evergy Missouri Metro intends to seek approval for through a Certificate of Convenience and Necessity ("CCN") proceeding. The Company anticipates filing the CCN application in the first half of 2026.

Q: What jurisdiction will the CCN request this asset by assigned to?

A: The Company intends to request that this asset be directly assigned to Evergy Missouri Metro in the upcoming CCN proceeding. Accordingly, the costs associated with this asset are not allocated on a total Metro basis and are not shared with other jurisdictions.

Q: How has the Company historically assigned generation assets?

A: Historically, the Company assigned generation assets to Evergy Metro and then allocated the associated plant investment and related revenue requirement among jurisdictions using Commission-approved allocation factors.

In contrast, for the new natural gas-fired generation associated with Adjustment RB-21, the Company intends to request direct assignment of the asset to EMM. Under a direct-assignment approach, the costs of the facility are not shared through jurisdictional allocators but are instead borne solely by the customers of the jurisdiction to which the asset is assigned.

Q: Why is the Company proposing to change its approach to assigning generation assets.

A: The Company is changing its approach to assigning certain generation assets in order to more closely align costs with the jurisdictions that directly benefit from those assets. The specific rationale and policy considerations supporting the use of direct assignment between EMM and EKM are discussed in detail in the direct testimony of Company witness Kevin Gunn. My testimony is limited to describing the accounting and ratemaking treatment associated with that approach.

Q: What types of costs are included in the CWIP balance for this adjustment?

A: The CWIP balance included in Adjustment RB-21 consists mostly of turbine reservation fees incurred to secure manufacturing and delivery capacity for a potential new natural gas-fired generating facility. Also included is estimated initial capital spend and Allowance for Funds Used During Construction ("AFUDC") to be incurred through June 30, 2026, the true-up date in this rate case. These reservation fees are preliminary, pre-construction costs that allow the Company to preserve equipment availability and pricing while the project proceeds through regulatory review.

Consistent with the Company's proposed approach to direct assignment, these costs are assigned entirely to EMM, as the generating facility is intended to be an EMM resource, as discussed in the testimony of Company witness Kevin Gunn.

Q: Why is CWIP for this new natural gas generation project included in rate base?

A: Including CWIP in rate base for this new natural gas generation project aligns the timing of cost recovery with the timing of the Company's capital investment and supports the Company's ability to finance the project at a reasonable cost. Recovery of CWIP during construction reduces the amount of interest that would otherwise accrue during construction and helps moderate the rate impact to customers once the facility is placed into service.

This ratemaking treatment reflects the policy framework established by Missouri law and is intended to balance customer protections with the need to ensure timely development of necessary generation resources.

CS-11 OUT OF PERIOD ITEMS

Q: Please explain adjustment CS-11.

A: The Company adjusted certain expense transactions recorded during the test year from the cost-of-service filing in this rate case. The following is a listing of the various components included in the adjustments:

- <u>Removed charges from test year.</u> The Company has identified certain costs recorded during the test year for which it is not seeking recovery in this rate proceeding. These costs for which the Company is not seeking recovery primarily include financial performance based officer long-term incentive compensation, certain officer expense report items and officer severance.

Additional severance payments made during the test year to non-officers are proposed to be amortized over a four-year period.

- Test Year Adjustments from Prior Orders. The Company eliminated test year amounts recorded on the books for items related to a prior rate case. These amounts are not ongoing expenses and should therefore be removed from the cost of service.

- Elimination of Various Costs and One Time Journal Entries. Various one-time journal entries were removed from the test year and also costs eliminated from the test year related to deferral accounting.

CS-61/RB-61 OTHER POST-EMPLOYMENT BENEFITS

Q: Please explain adjustments CS-61 and RB-61.

A: CS-61 is the adjustment for Other Post-Employment Benefits ("OPEB") expense as recorded under Accounting Standards Codification No. 715, Compensation-Retirement Benefits to an annualized level for ratemaking purposes for Metro's portion of the Evergy postretirement benefit plans. Previously, the accounting guidance was referred to as Financial Accounting Standards No. 106 "Employers' Accounting for Postretirement Benefits Other Than Pensions" ("FAS 106") and this description will continue to be used in the regulatory process. CS-61 also includes an adjustment for the Wolf Creek Nuclear Operating Corporation's ("WCNOC") OPEB expense based on the cash paid for OPEB costs rather than the FAS 106 expense amount. RB-61 is the roll forward of the FAS 106 regulatory liability and the prepaid OPEB regulatory asset to the projected true-up date of June 30, 2026.

Q: Do these adjustments take into consideration OPEB expense billed to joint partners, billed to affiliated companies, and charged to capital?

A: Yes, Evergy Metro total company costs, for adjustment CS-61, are adjusted for projected billings to affiliates, joint partners and charges to capital, based on data from the payroll adjustment discussed later in this testimony (adjustment CS-50). Adjustment RB-61 also takes into account billings to joint partners and affiliates, but the balances are before charges to capital.

Q: Please explain the components of adjustment CS-61.

A: CS-61 has three components which include (1) the annualized FAS 106 expense for the Company's OPEB plans based on the projected 2026 cost provided by the Company's actuary, Willis Towers Watson; (2) the Company's portion of the WCNOC OPEB benefits based on the amount contributed to the plan to pay for OPEB costs, also referred to as the "pay as you go" amount; and (3) the five-year amortization of the FAS 106 regulatory liability.

Q: Was annualized OPEB expense determined in accordance with established regulatory practice?

A: Yes, annualized OPEB expense was determined based on the methodology consistent with the Non-Unanimous Stipulation and Agreement ("Non Unanimous S&A") in the 2022 rate case.

Q: What is the amount of FAS 106 expense on an Evergy Metro total company basis currently built into rates?

A: The Non-Unanimous S&A established the annual FAS 106 amount in rates at $256,406 (Evergy Metro total company), after removal of capitalized amounts and the portion of Evergy Metro's total company annual OPEB cost allocated to Evergy Metro's joint partners, but before the inclusion of FAS 106 amortization and the Company's portion of WCNOC OPEB benefits.

Q: What is the comparable level of FAS 106 expense on an Evergy Metro total company basis included in cost of service for this case?

A: The comparable amount included in cost of service in this case is $(278,246). Since the expense has fallen below zero, EMM is proposing to set the expense level at $0 per the Stipulation and Agreement ("S&A") language in the ER-2010-0355 case where the OPEB Tracker was established. This treatment of negative OPEB expense is discussed in further detail below.

Q: Please explain the FAS 106 regulatory liability.

A: This regulatory liability represents the cumulative unamortized difference in FAS 106 OPEB expense for ratemaking purposes and the postretirement expense built into rates, except any deferral that was driven by negative OPEB expense. These deferrals are not eligible for rate base treatment per the S&A language in the ER-2010-0355 case where the OPEB Tracker was established and have been excluded from the RB-61. This regulatory treatment of deferrals driven by negative OPEB expense is discussed in further detail below.

Q: How was the FAS 106 regulatory liability rolled forward to the June 30, 2026 balance?

A: The Evergy Metro total company, FAS 106 OPEB regulatory liability balance at May 31, 2022 was adjusted for the projected amortizations for the June 1, 2022 through June 30, 2026 time period. Before inclusion in rate base, the appropriate Missouri jurisdictional allocation factor was applied to the total company amount. The deferrals from June 1, 2022 through June 30, 2026 were not included in the FAS 106 OPEB regulatory liability as Evergy is, and has been experiencing negative expense and any deferral that results from negative expense will not be included in the FAS 106 rate base liability, and is discussed further below in discussion on Docket ER-2010-0355 .

Q: Was the Company's portion of WCNOC costs included in the FAS 106 regulatory liability adjustment for the June 1, 2022 through June 30, 2026 period?

A: No, the WCNOC portion was not included per the S&A in the 2022 Case.

Q: What is the projected FAS 106 regulatory liability balance for EMM at June 30, 2026?

A: The FAS 106 regulatory liability for EMM is projected to be ($2,209,703) at June 30, 2026 on a Missouri jurisdictional basis. Historically, the FAS 106 regulatory asset/liability were reported at the Evergy Metro total company level. With this update, we improved the OPEB adjustment process by recording Missouri specific balance directly, eliminating the need for any allocation.

Q: Is the FAS 106 regulatory liability properly includable in rate base?

A: Yes, the FAS 106 regulatory liability is included in rate base consistent with the Non-Unanimous S&A . The FAS 106 liability and associated amortizations are now being presented as an EMM jurisdictional number, different from 2022 when a total company number was presented.

Q: Please explain the treatment of the negative OPEB expense and how the resulting deferrals impact the FAS 106 regulatory liability established in Case No. ER-2010-0355?

A: MPSC Staff Report in ER-2010-0355 specifically states that "if the OPEB expense becomes negative, a regulatory liability equal to difference between the level of OPEB expense built into rates in that period and $0 would be established. Since this is a cash item, the regulatory asset or liability would be included in rate base and amortized over 5 years in the next rate case." Thus, the Company proposes to include $0 for OPEB expense in the cost of service and has excluded deferrals resulting from negative expense from the amount of the FAS 106 regulatory liability included in rate base in this rate filing.

Q: Can you cite other cases where this treatment has been utilized?

A: Yes. In Case No. ER-2010-0130 (Empire), the Non-Unanimous S&A specifically states in Appendix C:

> 3. In the case that OPEB expense becomes negative, the Company is ordered to set up a regulatory liability to offset the negative expense. In future years, when OPEB expense becomes positive again, rates will remain zero until the regulatory liability that was created by negative expense is reduced to zero. The OPEB regulatory liability will be reduced by the amount of subsequent positive OPEB expense experienced by the Company. This regulatory liability is a non-cash item and should be excluded from rate base in the future years. A regulatory asset or liability will be established on the Company's books to track the difference between the level of OPEB expense during the rate period and the level of OPEB expense built into rates for that period. If the OPEB expense during the period is more than the expense built into rates for the period, the Company will establish a regulatory asset. If the OPEB expense during the period is less than the expense built into rates for the period, the Company will establish a regulatory liability. If the OPEB expense becomes negative, a regulatory liability equal to the difference between the level of OPEB expense built into rates for that period and $0 will be established. Since this is a cash item, the regulatory asset or liability will be included in rate base and amortized over five years at the next rate case.

Q: How did the MPSC Staff address this negative FAS 106 OPEB expense in the most recent Empire rate case (ER-2024-0261)?

A: MPSC Staff witness Matthew Young's direct testimony states:

> **Q. What does Staff recommend for the FAS 106 OPEB expense in the current case?**
>
> A. Staff recommends continuing the historical ratemaking approach to OPEB expense and recommends the continuation of historically approved trackers and agreements. In the current case, Staff's direct revenue requirement reflects $0 of ongoing OPEB expense and the

> current tracker balance as of September 30, 2024, amortized over five years. Staff's rate base does not include liability amounts caused by negative OPEB expense. However, Empire has an OPEB liability as of September 30, 2024, due to past positive OPEB expenses that were less than the OPEB allowance in rates. This balance is included in Staff's rate base.
>
> **Q. Why does Staff recommend $0 for ongoing OPEB expense and exclude rate base driven by negative OPEB expense?**
>
> A. The stipulation in Empire's Case No. ER-2010-0130, and carried forward in future agreements, has language in the event that OPEB expense becomes negative, as the actuary has calculated for 2024. Prior agreements state that in the event of negative expense, rates should be set to zero until the time the related OPEB liability can be reduced by positive OPEB expense. The agreement in ER-2010-0130 also specifies that the related liability is a non-cash item and should be excluded from rate base in future years. Staff's revenue requirement reflects this agreement."

Q: Please explain the FAS 88 regulatory asset.

A: This regulatory asset represents the cumulative deferred costs for OPEB plan special termination benefits. Because these do not occur on a regular basis and vary over time, they are tracked by vintage for ease of calculation and discussion. This case will include one vintage for the 2022 Special Termination Benefits.

Q: What is EMM's projected cumulative FAS 88 regulatory balance at June 30, 2026?

A: EMM's projected FAS 88 regulatory asset at June 30, 2026 is $2,345,875 on a MO jurisdictional basis, all of which consists of the 2022 vintage for the special termination benefits. This projection did not include retiree life buyouts that occurred in October of 2025 but will be included in the FAS 88 regulatory balance at true-up in June 2026. Historically, the FAS 88 regulatory asset/liability were reported at the Evergy Metro total company level. With this update, we improved the OPEB adjustment process by recording Missouri specific balance directly, eliminating the need for any allocation.

CS-65/RB-65 PENSION COSTS

Q: Please explain adjustments CS-65 and RB-65.

A: CS-65 is the adjustment for pension expense as recorded under Accounting Standards Codification No. 715, Compensation-Retirement Benefits to an annualized level for ratemaking purposes. Previously, the accounting guidance was referred to as Financial Accounting Standards No. 87 "Employers' Accounting for Pensions" ("FAS 87") and No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits" ("FAS 88") and these descriptions will continue to be used in the regulatory process. RB-65 is the roll forward of the FAS 87, FAS 88 and prepaid pension regulatory assets to their projected June 30, 2026 balances.

Q: Do these pension adjustments take into consideration pension expense billed to joint partners, billed to affiliated companies, and charged to capital?

A: Adjustment CS-65 takes into account billings to joint partners and affiliates and charges to capital based on data from the payroll adjustment CS-50. Adjustment RB-65 also takes into account billings to joint partners and affiliates, but the balances are before charges to capital.

Q: Do these pension adjustments include the effects of the Company's interest in the Wolf Creek generating station pension plan?

A: Yes.

Q: Please explain the components of adjustment CS-65, pension expense.

A: CS-65 consists of the Evergy Metro's total company share of the annualized FAS 87 expense, which is based on the projected 2026 total company cost provided by the

Company's actuarial firm, Willis Towers Watson. In addition, annualized pension expense includes the five-year amortization of the FAS 87 and FAS 88 regulatory assets.

Q: Was annualized pension expense determined in accordance with established regulatory practice?

A: Yes, annualized pension expense continues to follow the methodology agreed to in the prior EMM rate proceeding, Case No. ER-2022-0129.

Q: What is the amount of FAS 87 expense on an Evergy Metro total company basis currently built into rates for EMM?

A: The Non-Unanimous S&A established the annual amount built into rates at $28,489,112 (Evergy Metro total company), after removal of capitalized amounts and the portion of Evergy Metro's total company annual pension cost that is allocated to Evergy Metro's joint partners associated with the Iatan and La Cygne generating stations, and before inclusion of the amortization of the FAS 87 and FAS 88 regulatory assets and Supplemental Executive Retirement Plan ("SERP") expense.

Q: What is the comparable level of FAS 87 expense included in cost of service for this case?

A: The comparable amount included in cost of service in this rate case for EMM is $13,480,844, which is Evergy Metro total company share.

Q: Please explain the FAS 87 regulatory asset?

A: This regulatory asset represents the projected cumulative unamortized difference in FAS 87 pension expense for ratemaking purposes and pension expense built into rates. The balance is rolled forward to June 30, 2026 to determine the proper amount to be included in rate base and upon which to base an annualized amortization in this case.

Q: How was the FAS 87 regulatory liability rolled forward to the June 30, 2026 balance?

A: The Evergy Metro total company FAS 87 pension regulatory liability balance at May 31, 2022 was adjusted by the projected total company difference between FAS 87 expense for Missouri ratemaking purposes and the FAS 87 expense built into rates for the period June 1, 2022 through June 30, 2026. The regulatory asset balance was also reduced by the projected amortizations for the June 1, 2022 through June 30, 2026 period. Before inclusion in rate base, the appropriate Missouri jurisdictional allocation factor was applied to the total company amount.

Q: What is EMM's projected amount at June 30, 2026 for the FAS 87 regulatory liability on an EMM jurisdictional basis?

A: EMM's FAS 87 regulatory liability is projected to be ($54,453,017) on a EMM jurisdictional basis at June 30, 2026.

Q: Why was a five-year amortization period used for the FAS 87 regulatory liability?

A: A five-year amortization period was used consistent with the 2022 Rate Case Pension and OPEB stipulated amounts.

Q: Is the FAS 87 regulatory liability properly includable in rate base?

A: Yes, it is included in rate base per the Non-Unanimous S&A Regarding Pensions and OPEBs. The FAS 87 liability and associated amortizations are now being presented as a EMM jurisdictional number, different from 2022 when an Evergy Metro total company number was presented. With this update, we improved the Pension adjustment process by recording Missouri specific balance directly, eliminating the need for any allocation.

Q: Please explain the FAS 88 regulatory asset.

A: This regulatory asset represents the cumulative deferred costs for pension plan settlements accounted for under FAS 88. Because these do not occur on a regular basis and vary over time, they are tracked by vintage for ease of calculation and discussion. This case will include five vintages: (1) the 2019, 2020, 2021, 2022 and 2023 settlement costs, and (2) and a correction related to vintages 2019-2021.

Q: What is EMM's projected cumulative FAS 88 regulatory balance at June 30, 2026?

A: EMM's projected FAS 88 regulatory asset at June 30, 2026 for the EMM jurisdictional balance consists of $834,822 for the 2019 vintage, $997,065 for the 2020 vintage, $971,412 for the 2021 vintage, $5,966,359 for the 2022 vintage, and $4,264,787 for the 2023 vintage, and $9,442,726 for the 2019, 2020 and 2021 actuarial report vintage correction.

Q: Why was a five-year amortization period used for the FAS 88 regulatory asset?

A: A five-year amortization period was used consistent with the Non-Unanimous S&A .

Q: Is the FAS 88 regulatory asset included in rate base?

A: No, it is not included in rate base in accordance with the Non-Unanimous S&A .

Q: Please explain the prepaid pension asset adjustment.

A: This asset represents the cumulative projected difference between pension expense computed under FAS 87 and contributions to the pension trusts. This adjustment was made to roll forward the prepaid pension regulatory asset to June 30, 2026 to determine the proper amount of the prepaid pension asset to be included in rate base.

Q: What is EMM's projected amount at June 30, 2026 for prepaid pension assets?

A: The EMM prepaid pension asset is projected to have a balance at June 30, 2026. The revenue requirement currently reflects a prepaid pension asset of $0 because, at the time the revenue requirement was developed, contribution levels for 2025 had not yet been estimated. A year-end entry for 2025 will recognize the excess contribution as a Prepaid Pension Regulatory Asset, which will result in a balance included in the true-up.

Q: Does EMM plan to include this amount for rate recovery at true-up?

A: Yes, it will be included in rate base at true-up. Based on the language in the Non-Unanimous S&A:

> [A] new Prepaid Pension Asset may be established if EMM's share of amounts contributed to the pension trust, as authorized for the reasons below, exceed the FAS 87 cost calculated pursuant to the Evergy GAAP method. Except as otherwise indicated below, the Signatories agree to allow the Company rate recovery for contributions made to the pension trust in excess of the FAS 87 cost calculated pursuant to the Evergy GAAP method for the following reasons:
>
> > a. The minimum required contribution under ERISA is greater than the FAS 87 cost level.
> >
> > b. Additional contributions are made to avoid or reduce Pension Benefit Guarantee Corporation ("PBGC") variable premiums or to avoid benefit restrictions or "at risk" status under ERISA. Such contributions will be examined in future rate cases and a determination will be made at that time as to the prudency and reasonableness of these contributions, and the appropriate and proper level recognized for ratemaking as a Prepaid Pension Asset.
> >
> > c. The Prepaid Pension regulatory asset will be continued and will be allowed rate base treatment for the excess of any contribution over the annual FAS 87 cost calculated pursuant to the Evergy GAAP method. This regulatory asset shall be used to satisfy, in whole or in part, the FAS 87 funding requirement described in paragraph 3 above. The Prepaid Pension Asset will be reduced as it is used to satisfy the FAS 87 funding requirement.
>
> 6. Any FAS 87 prepaid pension asset, other than the amount authorized in paragraph 5 (paragraph above), will not earn a return in future regulatory proceedings.

Q: Does annualized pension expense include SERP expense?

A: No, SERP expense is considered separately in adjustment CS-62, which is discussed later in this testimony.

CS-50 PAYROLL

Q: Please explain adjustment CS-50.

A: EMM annualized payroll expense is based on employee headcount as of June 30, 2025 adjusted for labor impacts of the energy efficiency rider implementation ("MEEIA"), multiplied by salary and wage rates expected to be in effect as of June 30, 2026. In addition, EMM removed base salaries for participants in the Early Retirement Program ("ERP") who left the company before year end 2025 and added back estimated replacement base salaries for positions expected to be filled prior to the true-up date of June 30, 2026.

Q: How were salary and wage rates determined?

A: Salary rates for non-bargaining employees were based on annual salary adjustments expected to be in effect as of June 30, 2026. Wage rates for bargaining unit (union) employees were based on contractual agreements or estimated increases projected at the true-up date. Any changes finalized from any union negotiations are expected to be reflected at the true-up date June 30, 2026 in this rate case.

Q: Were amounts over and above base pay, such as overtime, premium pay, etc. included in the payroll annualization?

A: Yes, overtime (including Wolf Creek overtime) was annualized at an amount equal to the average of overtime hours incurred for the 12-month periods ending December 2022, December 2023 and June 2025, including a calculation to current 2026 dollars. In addition, overtime amounts were adjusted to exclude impacts of the Wolf Creek Refueling outage for which amounts were reflected in adjustment CS-35. Temporary and summer employees O&M labor were annualized at an average of these same three 12-month periods as well. Amounts were included for other categories at test year levels.

Q: Does annualized payroll include payroll Evergy Metro billed to EMW, EKC and other affiliates and does it include payroll billed from EKC?

A: The annualization process includes all payroll, since all employees are either Evergy Metro employees or EKC employees which also includes employees at Wolf Creek. However, annualized payroll included in this rate proceeding was reduced by the amount that would be billed out to these affiliated companies or billed from EKC.

Q: Does the payroll annualization adjustment take into consideration payroll billed to joint venture partners and payroll charged to capital?

A: Yes, the payroll annualization adjustment takes these factors into consideration.

Q: How was the payroll capitalization factor determined?

A: The Company used a three-year average payroll capitalization factor, for both total Evergy Metro and Wolf Creek, as being representative of payroll capitalization going forward. The periods included in the three-year average capitalization factor included the 12 months ending December 2022, December 2023 and June 2025.

CS-51 INCENTIVE COMPENSATION

Q: Please explain adjustment CS-51.

A: EMM annualized incentive compensation based on a three-year average of payouts for the 2023, 2024, and 2025 Plan Years for AIP Plan (executives only), Variable Compensation Plan ("VCP") (non-union management personnel) and Wolf Creek PAR (union). Adjustments were made to the annualized amount to remove all incentive compensation that was associated with metrics tied to earnings per share portion included in the AIP Plan (executives only) and the Variable Compensation Plan ("VCP") (non-union management personnel).

Q: Does this adjustment take into consideration incentive compensation billed to joint venture partners, billed to affiliated companies, and charged to capital?

A: Yes**,** it is based on data from the payroll adjustment discussed earlier in this testimony (adjustment CS-50).

Q: Aside from the VCP, AIP, and PAR incentive plans, is there another incentive plan component to this adjustment?

A: Yes. This adjustment also averages the Power Marketing incentive plan actual payouts for the same time period as described above. The Power Marketing incentive plan covers a group of employees whose responsibility is managing Evergy Inc's load and owned assets. This group also serves a secondary purpose in that it provides and shares resources and functions to manage assets for customers and other contracting parties, and to execute non-asset-based energy trading. This resource sharing creates efficiencies and benefits to EMM and importantly lowers costs at which EMM provides service to its customers. The incentive plan is offered to this functional set of employees in the power marketing area. All incentive amounts from the base incentive plan were split according to the percentage of asset metrics to non-asset metrics. Only the amounts booked above the line and related to asset metrics were included in the three-year average. Any additional incentive amounts from purely non-asset-based market activity are attributed to non-asset metrics at 100%, and therefore not included in cost of service in this case.

CS-53 PAYROLL TAXES

Q: Please explain adjustment CS-53.

A: The Company annualized FICA, Medicare, and FUTA payroll tax expense by applying the tax rate (assuming the FUTA and SUTA ceiling had been achieved) to the annualized O&M portions of base salary plus VCP, executive incentive compensation, overtime, premium, temporary wages, and EMM's share of Wolf Creek. This adjustment also removes the payroll tax impacts of the MEEIA rider and the ERP.

Q: Does this adjustment take into consideration payroll tax expense billed to joint venture partners, billed to affiliated companies, and charged to capital?

A: Yes**,** it is based on data from the payroll adjustment discussed earlier in this testimony (adjustment CS-50).

CS-62 SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN ("SERP")

Q: Please explain SERP Expense.

A: SERP is an additional component to the standard pension plan and is customary in many companies due to limitations imposed by the IRS on standard retirement plans for executives.

Q: **Was SERP expense included in Adjustment CS-65 with pension costs?**

A: No.

Q: Please explain the CS-62 SERP Adjustment.

A: Under the Evergy SERP plan, SERP costs are funded when the benefit is paid. Given that some plan participants elect a lump-sum payment method rather than an annuity, annual funding requirements can vary significantly between years. By using an average of total funding over a typical single life annuity period of 14.3 years for lump-sum payments, the adjustment reflects actual cash payments spread over time. Monthly annuity payments were normalized using a five-year average.

Q: Was the SERP cost associated with the Company's interest in the Wolf Creek generating station normalized in a similar manner?

A: Yes, it was.

CS-71 INJURIES AND DAMAGES

Q: Please explain adjustment CS-71.

A: The Company normalized Injuries and Damages ("I&D") costs based on a three-year average payout history during the 12-month periods ending June 2023, June 2024, and June 2025, as reflected by amounts relieved from Federal Energy Regulatory Commission ("FERC") account 228.2. This account captures all accrued claims for general liability, workers' compensation, property damage, auto liability costs, etc. The expenses are included in FERC account 925 as the costs are accrued. The liability reserve is relieved when claims are paid under these four categories.

Q: Does account 925 also include costs charged directly to that account?

A: Yes, for smaller dollar claims that are recorded directly to expense, the Company averaged these expenses over the same three-year average.

Q: Why were multi-year averages chosen?

A: I&D claims and settlements of these claims can vary significantly from year-to-year. A period of three years was used to establish an appropriate on-going level of this expense by leveling out fluctuations in the payouts that can exist from one year to the next depending on claims activity and settlements.

Q: Please explain the second part of this adjustment.

A: The Company is proposing to set up an I&D reserve due to the unpredictability of expenses associated with these types of claims, rather than trying to predict precisely when and in what amount these costs will be incurred. The cost to build up the reserve is recorded as a consistent expense month to month and included in rates. This reserve, once established, will provide a smoothing of annual expenses associated with I&D claims which are volatile year to year.

Q: Does the Company have an I&D Reserve in any other jurisdiction?

A: Yes, the Company has had an I&D Reserve established in both its EKC and EKM jurisdictions. Establishing an I&D Reserve for EMM will provide for more consistency in accounting across the operating jurisdictions.

Q: Please explain how the reserve amount was determined.

A: The Company is proposing to begin establishing the reserve by increasing operating expense equal to the annual amount calculated from a three-year average of claims experience incurred over a three-year period.

CS-72 STORM RESERVE

Q: Please explain why the Company is proposing to establish a storm reserve in this proceeding.

A: Storms are a normal occurrence in our service territory. When they occur, they can be quite devastating in many ways and have a significant financial impact on the utility. The establishment of a storm reserve would allow EMM to collect in rates the cost of storms that are significant in nature and are likely to occur in the future. Collecting amounts in rates, prior to when the storm costs are actually incurred, assists the Company in maintaining the distribution system to be shared by current and future customers and avoid placing all the burden on future customers who are using the system at the time the storm occurs.

Q: What are the benefits of a storm reserve?

A: The storm reserve will be used to levelize expenditures associated with significant storms benefitting both the customers through reduced rate volatility and the Company by lessoning the financial burden impact through a smoothing of month-to-month storm expenditures associated with the unpredictable, but likely significant storm events. The utility's focus and number one priority at the time of significant storms should be in restoring customer services that have been impacted by outages. The use of a storm reserve allows the Company to do just that and focus on service restoration and not on the current financial implications, since these costs will be spread over time instead of the constant sporadic and unpredictable uptick in costs when storms arrive.

Q: What is the Company proposing in adjustment CS-72?

A: The Company is proposing to set a reserve level and annualized level based upon a three-year average of storms costs (12-months ending December 2022, 2023, and 2024), where the costs related to individual storms were greater than $250,000. An annual amount equal to the three-year average has been included in the revenue requirement on an on-going basis. This is needed to continue to cover expenses paid out of the reserve over time due to the unpredictable and sporadic nature of storm events. The implementation of this reserve will be used to cover intermediate to large storms by using a $250,000 minimum storm level, but in the event a storm is very significant and impactful to Company operations, this request does not preclude the Company from requesting an Accounting Authority Order if the magnitude of the storm warrants the request, as has been done historically. In addition, please see the testimony of Company Witness Ryan Mulvany for additional discussion on why the Company has requested a Storm Reserve in this rate case.

Q: How will storm costs be identified and tracked?

A: When a storm occurs, restoration costs will be tracked by project ID in Maximo under work orders. The costs are monitored, and once a single event accumulates O&M costs in excess of $250,000 these costs would be moved out of expense and booked as an offset to the established storm reserve.

Q: Does the Company have a Storm Reserve in any other jurisdictions?

A: Yes, the Company has had a Storm Reserve established in both its EKC and EKM jurisdictions. Establishing a Storm Reserve for EMM will provide for more consistency in accounting across the operating jurisdictions.

VI. CIP/CYBER SECURITY O&M TRACKER

Q: Why is the Company requesting a Critical Infrastructure Protection ("CIP") Cybersecurity Tracker ("Security Tracker")?

A: The Company fully anticipates these expenses related to CIP and Cyber Security will increase over the next few years, and more importantly, in emergency situations we need to be able to respond quickly and with flexibility to new threats surfacing every day. A tracker provides this ability. In the past, costs in this area have proven to be unpredictable and can vary from amounts established in base rates. Additionally, the Company is including a security component to the Security Tracker because security threat costs are expected to have an increasing impact on the Company.

Q: Please explain.

A: The security threat landscape continues to increase and evolve. Critical infrastructure—the electric grid at all voltage levels—is a rich target for United States' adversaries. In addition, there have been increases in violent domestic attacks on the nation's critical infrastructure. While EMM has been responsive to compliance with regulations, reporting and risk-based prudent security measures, the ever-changing attack surface requires the Company to be flexible and expeditiously deploy prudent security response measures to protect the assets that serve its customers. See the testimony of Company witness Gary Johnson who provides further testimony on the need for a tracker and offers deeper insight into evolving cyber and physical security challenges Evergy faces and the measures being taken to address them.

Q: Does the requested security tracker include internal labor costs?

A: It does not include internal labor costs for Evergy employees.

Q: How are the costs defined that would be included in the CIPS/Cybersecurity Tracker?

A: The O&M CIPS/Cybersecurity Tracker would be defined in the same manner as is included in Evergy's Kansas jurisdictions. In Docket No. 23-EKCE-775-RTS, Evergy Kansas Metro and Evergy Kansas Central were granted continuation of an O&M tracker defined as follows:

> The Security Tracker is for incremental O&M costs spent to meet continuously emerging security threats to critical infrastructure and growing regulatory requirements for protection of critical infrastructure, inclusive of Department of Defense ("DOD"), Department of Homeland Security ("DHS"), Department of Energy ("DOE"), Nuclear Regulatory Commission ("NRC"), Securities and Exchange Commission ("SEC"), Federal Communications Commission ("FCC"), Federal Energy Regulatory Commission ("FERC"), North American Electric Reliability Corporation ("NERC"), etc., or security needs. Historically, the impacts to

> Evergy have been heavily focused on cybersecurity and the growing attack surface in cyber warfare that require the critical infrastructure industries to invest in security to protect the electric system. Today, the threats to critical infrastructure persist and continue to grow inclusive of physical security. These regulatory obligations, such as NERC Critical Infrastructure Protection ("CIP") Standards, are publicly available and subject to federal audits. Security needs are driven by many government entities, threat intelligence and analytics as well as industry best practices.

Q: Is the Company providing a sunset provision in this rate case associated with the Security Tracker?

A: Yes, the Security Tracker will terminate upon completion of the first EMM full general rate proceeding filed on or after January 1, 2031. If EMM wishes to continue the Security Tracker beyond that time, EMM must propose such action to the Commission. In that proceeding, EMM may request the Security Tracker mechanism be reauthorized and continued. EMM will bear the burden of showing the extension of the Security Tracker is in the public interest and will result in just and reasonable rates. All other parties retain the right to object to an extension of the Security Tracker in that future proceeding.

Q: If the Commission approves the continuation of the Security Tracker what are the base level of costs included in the revenue requirement in this case?

A: The base level of O&M included in the revenue requirement for Evergy Metro total is $4,492,878.

Q: Does this conclude your 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 RONALD A. KLOTE

STATE OF MISSOURI)
) **ss**
COUNTY OF JACKSON)

Ronald A. Klote, being first duly sworn on his oath, states:

1. My name is Ronald A. Klote. I work in Kansas City, Missouri and I am employed by Evergy Metro, Inc. as Sr. Director, Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Evergy Missouri Metro consisting of thirty-six (36) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Ronald A Klote

Ronald A. Klote

Subscribed and sworn before me this 6th day of February 2026.

Anthy R Westenkirchner

Notary Public

My commission expires: April 26, 2029

ANTHONY R WESTENKIRCHNER
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES APRIL 26, 2029
PLATTE COUNTY
COMMISSION #17279952

Evergy
2026 RATE CASE - MO METRO -Direct
TY 6/30/25; Cut-Off 12/31/25; True-Up 6/30/26

Revenue Requirement

Line No.	Description	7.655% Return
	A	B
1	Net Orig Cost of Rate Base (Sch 2)	$ 3,879,303,485
2	Rate of Return	7.6546%
3	Net Operating Income Requirement	$ 296,945,165
4	Net Income Available (Sch 9)	190,057,567
5	Additional NOIBT Needed	106,887,597
6	Additional Current Tax Required	33,465,438
7	Gross Revenue Requirement	$ 140,353,035

Evergy
2026 RATE CASE - MO METRO -Direct
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Rate Base

Line No.	Description	Amount	Witness	Adj No.
	A	B	C	D
1	Total Plant :			
2	Total Plant in Service - Schedule 3	7,574,164,367	Branson	RB-20
3	Subtract from Total Plant:			
4	Depreciation Reserve - Schedule 6	3,299,006,548	Branson	RB-30
5	Net (Plant in Service)	4,275,157,820		
6	Add to Net Plant:			
7	Cash Working Capital - Schedule 8	(73,302,627)	Branson	Model
8	Materials and Supplies - Schedule 12	109,962,033	Branson	RB-72
9	Prepayments - Schedule 12	11,688,670	Branson	RB-50
10	Fuel Inventory - Oil - Schedule 12	7,998,494	Tucker	RB-74
11	Fuel Inventory - Coal - Schedule 12	35,384,148	Tucker	RB-74
12	Fuel Inventory - Additives - Schedule 12	515,925	Tucker	RB-74
13	Fuel Inventory - Nuclear - Schedule 12	50,279,663	Nunn	RB-75
14	Pre-MEEIA DSM Programs	(2,864,388)	Kramer	RB-100
15	Property Tax Tracker Deferral	30,747,486	Hardesty	RB-126
16	Regulatory Asset - Iatan 2	10,873,653	Kramer	RB-26
17	Regulatory Asset - PAYS	482,307	Kramer	RB-86
18	Regulatory Asset - PISA Deferral	221,189,122	Kramer	RB-85
19	Regulatory Asset - Pensions	(54,453,013)	Klote	RB-65
20	Regulatory Asset (Liab) - OPEBs Tracker	(2,209,703)	Klote	RB-61
21	CWIP - New Gas Generation	86,363,196	Klote	RB-21
22	Deferred Income Taxes - Nuclear PTC - Sch 13	59,661,162	Hardesty	RB-125
23	Subtract from Net Plant:			
24	Cust Advances for Construction-MO	968,632	Branson	RB-71
25	Customer Deposits-MO	701,734	Branson	RB-70
26	Deferred Income Taxes - Schedule 13	777,630,317	Hardesty	RB-125
27	Def Gain on SO2 Emissions Allowances-MO	13,429,303	Kramer	RB-55
28	Regulatory Liability - Nuclear PTC	95,146,965	Hardesty	RB-125
29	Income Eligible Weatherization	293,511	Kramer	RB-101
30	Total Rate Base	3,879,303,485		

Evergy
2026 RATE CASE - MO METRO -Direct
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Income Statement

Line No.	Description	Total Company	Adjustment	Adjusted Total Comany	Adjusted Jurisdictional
	A	B	C	D	F
1	Operating Revenue	1,895,230,227	(39,953,046)	1,855,277,181	1,021,642,985
2	Operating & Maintenance Expenses:				
3	Production	632,149,359	(72,643,850)	559,505,509	311,690,956
4	Transmission	69,370,130	13,953,605	83,323,735	47,986,782
5	Distribution	57,719,655	195,053	57,914,708	33,686,092
6	Customer Accounting	(21,440,920)	3,688,260	(17,752,660)	(7,564,411)
7	Customer Services	17,951,571	(10,370,996)	7,580,575	5,936,863
8	Sales	364,162	11,634	375,796	197,057
9	A & G Expenses	70,620,559	(7,266,003)	63,354,556	34,511,819
10	Total O & M Expenses	826,734,516	(72,432,295)	754,302,221	426,445,156
11	Depreciation Expense	385,548,969	150,463,940	536,012,909	282,773,925
12	Amortization Expense	78,376,839	(66,859,989)	11,516,850	8,642,432
13	Amortization Regulatory Debits & Credits	(41,504,015)	38,561,060	(2,942,955)	20,647,098
14	Taxes other than Income Tax	147,354,763	5,478,871	152,833,634	82,682,827
15	Net Operating Income before Tax	498,719,156	(95,164,634)	403,554,522	200,451,546
16	Income Taxes Current	46,176,624	53,842,651	100,019,275	47,691,113
17	Income Taxes Deferred	617,821	(70,099,593)	(69,481,772)	(35,767,987)
18	Investment Tax Credit	(2,811,342)	(27,077)	(2,838,419)	(1,529,147)
19	Total Taxes	43,983,103	(16,284,019)	27,699,084	10,393,979
20	Total Net Operating Income	454,736,053	(78,880,615)	375,855,438	190,057,567

Evergy
2026 RATE CASE - MO METRO -Direct
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Summary of Adjustments

Line No.	Adj No.	Description	Witness	Increase (Decrease)			
	A	B		D	E	F	G
				Adjust to 06/30/2026 - True Up Date			
	JURISDICTIONAL COST OF SERVICE			Total Adjustments Incr (Decr)	Allocated Adjs Incr (Decr)	100% MO Adjs Incr (Decr)	100% KS & Whsl Adjs (2) Incr (Decr)
1	**OPERATING REVENUE**						
2	**Operating Revenue - Schedule 9, line 41**						
3	R-20	Normalize MO retail revenues (MO only)	Bass / Jaynes	20,657,355		20,657,355	
4	R-21a	Adjust MO forfeited disc for R-21a LPC (MO only)	Kramer	14,885		14,885	
5	R-21b	Adjust MO forfeited disc for R-21b LPC - ASK (MO only)	Kramer	135,317		135,317	
6	CS-23	Remove FAC Under Recovery	Nunn	6,362,792		(656,200)	7,018,992
7	R-35	Normalize Bulk Power Sales	Tucker	(65,115,723)	(65,115,723)		
8	R-40	PAYS Revenue Offset	Kramer	2,061		2,061	
9	R-80	Transmission Revenues - ROE	Rueter	(112,731)	(112,731)		
10	R-82	Transmission Revenues - Annualized	Nunn	(1,762,098)	(1,762,098)		
11	R-88	Misc Revenue	Kramer	(236,093)		(236,093)	
12	R-99	Low Income Solar	Kramer	101,189		101,189	
13		**Operating Revenue - Schedule 9, line 41**		(39,953,046)	(66,990,552)	20,018,514	7,018,992
14							
15	**OPERATING EXPENSES - Schedule 9, line 336**						
16	CS-4	Reflect KCREC test year bad debt expense in METRO's COS	Kramer	4,470,231		3,254,919	1,215,312
17	CS-9	Reflect KCREC test year bank commitment fees in METRO's COS	Branson	8,056,243	8,056,243		
18	CS-10	Reflect test year interest on customer deposits in COS	Branson	98,155		70,191	27,964
19	CS-11	Reverse prior period and non-recurring test year amounts.	Klote	(3,810,516)	(3,810,516)		
20	CS-20a	Normalize bad debt expense related to test year revenue	Kramer	1,765,431		1,765,431	
21	CS-20b	Normalize bad debt expense related to jurisdictional "Ask"	Kramer	758,034		758,034	
22	CS-22	Amortize deferred gain on sale of SO2 emissions allowances	Kramer	0	0	0	

Evergy
2026 RATE CASE - MO METRO -Direct
TY 6/30/25; Cut-Off 12/31/25; True-Up 6/30/26

Summary of Adjustments

Line No.	Adj No.	Description	Witness	Increase (Decrease)			
	A	B		D	E	F	G
				Adjust to 06/30/2026 - True Up Date			
	JURISDICTIONAL COST OF SERVICE			**Total Adjustments**	**Allocated Adjs**	**100% MO Adjs**	**100% KS & Whsl Adjs (2)**
				Incr (Decr)	**Incr (Decr)**	**Incr (Decr)**	**Incr (Decr)**
23	CS-23	Remove FAC Under Recovery	Nunn	(4,751,501)		1,554,914	(6,306,415)
24	CS-24	Normalize fuel and purchase power energy (on system)	Tucker	(77,021,133)	(77,696,896)	729,515	(53,752)
25	CS-25	Normalize purchased power capacity costs	Tucker	0	0		
26	CS-27	Wolf Creek Water Contract	Kramer	28,625	28,625		
27	CS-36	Annualize Wolf Creek refueling outage amortization	Kramer	327,570	327,570		
28	CS-37	Adjust Nuclear decommissioning expense	Branson	0			
29	CS-39	IT Software Maintenance	Kramer	461,925	461,925		
30	CS-40	Normalize Transmission maintenance expense	Kramer	38,722	38,722		
31	CS-41	Normalize Distribution maintenance expense	Kramer	(1,136,485)	(1,136,485)		
32	CS-42	Normalize Generation maintenance expense	Kramer	3,070,068	3,070,068		
33	CS-43	Nuclear Maintenance	Kramer	(775,066)	(775,066)		
34	CS-44	Adjust cost of Economic Relief Pilot Program (ERPP) (MO only)	Kramer	104,913		104,913	
35	CS-45	Normalize transmission of electricity by others	Nunn	12,913,658	12,913,658		
36	CS-46	Critical Needs	Kramer	14,122		14,122	
37	CS-47	Rehousing Pilot	Kramer	77,680		77,680	
38	CS-50	Annualize salary and wage expense for changes in staffing levels and base pay rates	Klote	4,471,448	4,471,448		
39	CS-51	Normalize incentive compensation costs- Value Link	Klote	1,361,545	1,361,545		
40	CS-60	Annualize other benefit costs	Kramer	(954,185)	(954,185)		
41	CS-61	Annualize OPEB expense	Klote	962,004	962,004		
42	CS-62	Normalize SERP expense	Klote	40,005	40,005		
43	CS-65	Annualize FAS 87 and FAS 88 pension expense	Klote	388,647	388,647		
44	CS-70	Annualize Insurance Premiums	Kramer	52,437	52,437		
45	CS-71	Normalize injuries and damages expense	Klote	(1,386,382)	(1,386,382)		
46	CS-76	Annualize interest on customer deposits	Branson	(12,116)		(8,789)	(3,327)
47	CS-78	Annualize KCREC bank fees related to sale of receivables	Branson	63,989	63,989		

Evergy
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	A	B		D	E	F	G
				Adjust to 06/30/2026 - True Up Date			
	JURISDICTIONAL COST OF SERVICE			Total Adjustments	Allocated Adjs	100% MO Adjs	100% KS & Whsl Adjs (2)
				Incr (Decr)	Incr (Decr)	Incr (Decr)	Incr (Decr)
48	CS-80	Amortize MO, KS and FERC rate case expenses	Kramer	420,000		420,000	
49	CS-85	Annualize regulatory assessments	Branson	1,042,719	408,284	634,435	0
50	CS-86	SPP Schedule 1 Admin Fee's	Nunn	1,844,833	1,844,833		
51	CS-89	Meter Replacement O&M	Kramer	452,179	452,179		
52	CS-90	Advertising	Kramer	(25,845)	(24,177)		(1,668)
53	CS-91	TOU Ongoing Expenses	Kramer	455,543		455,543	
54	CS-92	Dues/Donations	Kramer	(30,404)	(30,404)		
55	CS-95	Amortization of Merger Transition Costs	Kramer	0	0		
56	CS-98	MEEIA	Kramer	(10,635,324)		(10,635,324)	
57	CS-100	Pre-MEEIA DSM Programs	Kramer	(514,664)		(514,664)	
58	CS-101	Income Eligible Weatherization	Kramer	153,309		153,309	
59	CS-108	Transource CWIP/FERC Incentives	Rueter	115,010	115,010		
60	CS-109	Lease Expense	Branson	(130,491)	(130,491)		
61	CS-112	Amort Iatan II Reg Asset	Kramer	0			
62	CS-116	Renewable Energy Standards	Kramer	0		0	
63	CS-117	Common-use Billings	Kramer	(13,361,816)	(12,608,924)	(752,892)	
64	CS-120	Annualize depr exp based on proposed jurisdictional depr rates applied to jurisdictional plant-in-service at indicated period (unit trains & transportation equipment)	Branson	(1,895,411)	(1,895,411)		
65		**Operating Expenses - Schedule 9, line 336**		(72,432,295)	(65,391,746)	(1,918,664)	(5,121,886)
66							
67	**Depreciation Expense - Schedule 9, line 343**						
68	CS-120	Annualize depreciation expense based on proposed jurisdictional depreciation rates applied to jurisdictional plant-in-service at indicated period	Branson	71,101,200	71,101,200		
69	CS-121	Annualize plant amortization expense based on jurisdictional amortization rates applied to unamortized jurisdictional plant-in-Service at indicated period	Branson	79,362,740	79,362,740		

Evergy
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	A	B		D	E	F	G
				Adjust to 06/30/2026 - True Up Date			
	JURISDICTIONAL COST OF SERVICE			Total Adjustments Incr (Decr)	Allocated Adjs Incr (Decr)	100% MO Adjs Incr (Decr)	100% KS & Whsl Adjs (2) Incr (Decr)
70				150,463,940	150,463,940	0	0
71	**Amortization Expense - Schedule 9, line 353**						
72	CS-121	Annualize plant amortization expense based on jurisdictional amortization rates applied to unamortized jurisdictional plant-in-Service at indicated period	Branson	(68,676,023)	(68,676,023)		
73	CS-122	Gen Plt Acctg Resv Adj Amortiz	Branson	1,816,034		1,816,034	
74				(66,859,989)	(68,676,023)	1,816,034	0
75	**Regulatory Debits & Credits - Schedule 9, line 385**						
76	CS-11	Reverse prior period and non-recurring test year amounts.	Klote	33,312,863		32,969,671	343,192
77	CS-61	Annualize OPEB expense	Klote	(761,510)		(761,510)	
78	CS-65	Annualize FAS 87 and FAS 88 pension expense	Klote	(19,312,111)		(19,312,111)	
79	CS-72	Storm Reserve	Klote	1,092,086		1,092,086	
80	CS-93	Amortization PISA Deferral	Kramer	9,886,482		9,886,482	
81	CS-113	Amortize Prospective Tracking	Kramer	43,387		43,387	
82	CS-126	Adjust property tax expense	Hardesty	15,185,080		15,185,080	
83	CS-131	Amort Electrification Deferred Asset	Kramer	308,359		308,359	
84	CS-133	Amort Customer Education Reg Asset	Kramer	(24,697)		(24,697)	
85	CS-134	Amort TOU Program Costs Reg Asset	Kramer	(393,026)		(393,026)	
86	CS-135	PAYS Amort	Kramer	35,934		35,934	
87	CS-136	COVID AAO Amort	Kramer	(866,406)		(866,406)	
88	CS-137	Amortization of Environmental Insurance Settlements Regulatory Liab.	Kramer	(866,507)		(866,507)	
89	CS-138	Amort Mandatory TOU Program Reg Asst	Kramer	921,921		921,921	
90	CS-141	Amort of Hedging Gain/Loss	Kramer	(793)		(793)	
91				38,561,060	0	38,217,868	343,192
92	**Taxes Other than Income - Schedule, line 395**						
93	CS-53	Annualize Payroll tax expense	Klote	1,067,571	1,067,571		
94	CS-126	Adjust property tax expense	Hardesty	4,369,136	4,369,136		

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	JURISDICTIONAL COST OF SERVICE			**Total Adjustments**	**Allocated Adjs**	**100% MO Adjs**	**100% KS & Whsl Adjs (2)**
				Incr (Decr)	**Incr (Decr)**	**Incr (Decr)**	**Incr (Decr)**
95	CS-128	KCMO Earnings Tax	Hardesty	42,164		42,164	
96				5,478,871	5,436,707	42,164	0
97	**Income Tax Expense- Schedule 9, line 412**						
98	CS-125	Reflect adjustments to Schedule 9, Allocation of Current and Deferred Income Taxes	Hardesty	(16,284,019)	(16,638,457)	354,438	
99				(16,284,019)	(16,638,457)	354,438	0
100							
101		**Total Electric Oper. Expenses**		38,927,569	5,194,422	38,511,841	(4,778,694)
102							
103		**Net Electric Operating Income - Schedule 9, line 414**		(78,880,615)	(72,184,974)	(18,493,327)	11,797,686
				0			

(1) All amounts are total company; if an adjustment is applicable to only KS or MO, it is so indicated

(2) These adjustments affect Kansas or Wholesale jurisdictions and are not discussed in testimony supporting the MIssouri rate case.

Evergy
2026 RATE CASE - MO METRO -Direct
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Allocation Factors

Line No.	Jurisdiction Factors	Missouri	KS & Wholesale	Total
	A	B	C	D
1	**Jurisdiction Factors**			
2	Missouri Jurisdictional	100.0000%	0.0000%	100.0000%
3	Kansas Jurisdictional	0.0000%	100.0000%	100.0000%
4	Non Jurisdictional/Wholesale	0.0000%	100.0000%	100.0000%
5	D1 - Demand Factor - Avg 4CP/12CP	51.9168%	48.0832%	100.0000%
6	D2 - Demand Factor - Transmission 12CP	52.3617%	47.6383%	100.0000%
7	E1 - Energy Factor with Losses (E1)	57.0799%	42.9201%	100.0000%
8	C1 - Customer - Elec (Retail only) (C1)	52.4371%	47.5629%	100.0000%
9	**Blended Factors**			
10	Sal & Wg - Salaries & Wages w/o A&G	53.0936%	46.9064%	100.0000%
11	PTD - Prod/Trsm/Dist Plant (excl Gen)	53.8732%	46.1268%	100.0000%
12	Dist Plt - Weighted Situs Basis	56.7998%	43.2002%	100.0000%
13	**Situs Basis Plant used for Distibution & Energy Storage**			
14	360 - Dist Land	72.6058%	27.3942%	100.0000%
15	360 - Dist Land Rights	63.1992%	36.8008%	100.0000%
16	361 - Dist Structures & Improvements	56.8254%	43.1746%	100.0000%
17	362 - Distr Station Equipment	67.3265%	32.6735%	100.0000%
18	363 - Distr Communication Equip	68.1613%	31.8387%	100.0000%
19	363 - Distr Communication Eq Retire	56.3986%	43.6014%	100.0000%
20	364 - Dist Poles, Towers & Fixtures	56.3420%	43.6580%	100.0000%
21	365 - Dist Overhead Conductor	59.7103%	40.2897%	100.0000%
22	366 - Dist Underground Circuits	56.4660%	43.5340%	100.0000%
23	367 - Dist Underground Conduct & Devices	51.4158%	48.5842%	100.0000%
24	368 - Dist Line Transformers	56.2117%	43.7883%	100.0000%
25	369 - Dist Services	55.7951%	44.2049%	100.0000%
26	370 - Dist Meters	56.3722%	43.6278%	100.0000%
27	370 - Dist AMI Meters	52.6200%	47.3800%	100.0000%
28	371 - Dist Customer Premise Installations	64.7063%	35.2937%	100.0000%
29	371 - Dist Electric Vehicle Charging Stations	57.5693%	42.4307%	100.0000%
30	373 - Dist Street Lights & Traffic Signals	47.9233%	52.0767%	100.0000%
31	387- Energy Storage - Plant	64.6760%	35.3240%	100.0000%
32	387- Energy Storage - Reserve	99.6634%	0.3366%	100.0000%

EVERGY METRO, INC.

JURISDICTIONAL ALLOCATION

OVERVIEW

The allocators that were utilized can be classified as “primary” allocators or “derived” allocators.

The primary allocators are based on the weather-normalized customer, energy, and demand information and are direct inputs.

The derived allocators are based on the Customer, Energy, and Demand allocators, possibly in combination with direct assignment. The derived allocators are calculated within the Revenue Requirement Model. They are often calculated as combinations of amounts that have previously been allocated using one or more of the primary allocators, or of direct assigned amounts, or both.

PRIMARY ALLOCATORS

The Customer allocator is based on the average number of customers in the Kansas and Missouri jurisdictions.

The Energy allocator is based on the total weather normalized kilowatt-hour usage by the Kansas and Missouri retail customers and the firm wholesale jurisdiction.

The Demand allocator (D1) for all functions other than Transmission is based on the average of the 12-month weather normalized average of the coincident peak demands for the Missouri and Kansas retail jurisdictional customers and the firm wholesale FERC jurisdictional customers (12 CP) and the 4-month weather normalized average of the coincident peak demands for the Missouri and Kansas retail jurisdictional customers and the firm wholesale FERC jurisdictional customers (4 CP).

The Demand allocator (D2) for Transmission is based on the average of the 12-month weather normalized average of the coincident peak demands for the Missouri and Kansas retail jurisdictional customers and the firm wholesale FERC jurisdictional customers (12 CP).

APPLICATION OF ALLOCATORS

Revenues

Retail revenues are the revenues received from retail customers in Kansas and Missouri.

Retail revenues are not allocated; rather, they are recorded by jurisdiction.

Miscellaneous revenues include forfeited discounts, miscellaneous services, rent from electric property, transmission service for others, and other electric revenues. These miscellaneous revenues are subdivided and, where possible, assigned directly to the jurisdiction where they are recorded. The miscellaneous revenues that are not directly assignable to a jurisdiction are grouped by functional categories and allocated on a basis consistent with that functional category.

Off-system cost of sales and firm bulk sales revenue are allocated primarily based on the Energy allocator. However, the Capacity and Fixed Firm Bulk Sales revenue are allocated based on Demand.

Sales for resale revenue is revenue from the full-requirements firm wholesale customers under FERC jurisdiction. This revenue is assigned totally to the FERC jurisdiction.

Fuel & Purchased Power Costs

Fuel & Purchased Power costs are primarily allocated based on the Energy allocator. There are a couple exceptions for the amortizations of SO2 Allowances and Solar Renewable Energy Credits that are assigned directly to the applicable jurisdiction.

Non-Fuel Operations and Maintenance Costs

Production O&M costs are allocated consistent with the allocation of production plant.

Transmission O&M costs associated with company owned transmission plant are allocated consistent with the allocation of transmission plant. Transmission Operation Load expense, Transmission of electricity by others, and costs associated with participation in SPP are allocated based upon the Energy allocator.

Distribution O&M costs are allocated consistent with the allocation of distribution plant.

Customer accounts expenses are primarily allocated using the Customer allocator. The exception is that the uncollectible accounts expense, interest on Customer Deposits and a portion of common use expense are assigned directly to the applicable jurisdiction.

Customer services and information expenses are allocated using the Customer allocator. The exception is that the MEEIA expense as well as the amortization of Customer Programs are assigned directly to the applicable jurisdiction.

Sales expenses are allocated using the Customer allocator.

A&G expenses are allocated using a number of methods depending on the cause of the cost. Salaries, employee benefits, printing device finance leases and injuries and damages expenses are allocated based on the allocated sum of the labor portion of the production, transmission, distribution, customer accounts, customer services and information, and sales expenses described previously. Regulatory expenses are assigned directly to the applicable jurisdiction, except for the FERC regulatory expense and miscellaneous regulatory expense, which are allocated based on the Demand allocator. Property insurance, general plant maintenance and duplicate charges-credit account are allocated based on the composite allocation of production, distribution and transmission plant. Fleet expense is allocated based on the allocation of total distribution plant. General advertising expense is allocated using the Customer allocator. The majority of the remaining A&G expenses are allocated using the Energy allocator.

Depreciation and Amortization Expenses

Depreciation expense is allocated based on the allocation of the corresponding plant to which it relates. Amortization expense related to software and leasehold improvements are allocated based on the composite allocation of production, transmission and distribution plant except for cloud development costs which are allocated based on the salaries and wages allocator. Other intangible amortizations are allocated based on the demand factor. Amortizations resulting from a prior regulatory order are assigned directly to the applicable jurisdiction.

Interest on Customer Deposits

Interest on customer deposits is assigned directly to the applicable jurisdiction.

Taxes

Property tax and Other Miscellaneous taxes are allocated based on the composite allocation of production, transmission and distribution plant. Payroll tax is allocated based on the allocated sum of the labor portion of the production, transmission, distribution, customer accounts, customer services and information, and sales expenses. Kansas City, Missouri Earnings Tax and Gross receipts tax applies only to the Missouri jurisdiction and is therefore assigned only to the Missouri jurisdiction.

Currently payable income tax is not allocated. Instead, payable income tax is calculated in the Revenue Requirement Model using the statutory tax rates for the appropriate jurisdiction and applying those rates to jurisdictional taxable income calculated in the Revenue Requirement Model. Income tax Credits for Nuclear, PTC, R&D, Wind, Solar and Fuels Tax are allocated based on Energy.

Deferred tax expense related to plant depreciation or plant/nuclear amortization is calculated using the statutory federal and state tax rates for the appropriate jurisdiction and applying a composite tax rate to the jurisdictional difference between tax return depreciation/amortization and book depreciation/amortization reflected in the Revenue Requirement Model.

Other deferred income tax expenses such as excess deferred tax amortizations and investment tax credit amortizations are allocated based on the composite allocation of production, transmission and distribution plant, except for amortizations resulting from a prior regulatory order. These are assigned directly to the applicable jurisdiction.

RATE BASE

Plant-in-Service and Reserve for Depreciation and Amortization

The Demand (D1) allocator is used to allocate production plant. The exception is for plant items that have been afforded different jurisdictional accounting treatment through past commission orders. Examples include the Iatan 1 and Iatan 2 plant disallowances as well as MO Gross Up AFUDC plant accounts. These items are assigned directly to the applicable jurisdiction.

Transmission plant is allocated using the Demand allocator (D2) except for MO Gross Up AFUDC plant accounts which are directly assigned to MO.

Distribution plant and Energy Storage are assigned based on physical location.

General plant is allocated based on the composite allocation of production, transmission, and distribution plant except for MO Gross Up AFUDC plant account which is directly assigned to MO.

Intangible plant consisting primarily of capitalized software is allocated based on the allocation factor considered most appropriate for the function of the software. For example, the customer information system is allocated based on the Customer allocation factor, whereas transmission-related software is allocated consistent with the allocation of Transmission plant. Software was transferred primarily to General plant with the implementation of FERC Order 898.

The reserves for accumulated depreciation and amortization are allocated based on the allocation of the plant with which they are associated. The exception is for reserve items that have been afforded different jurisdictional accounting treatment through past commission orders. Examples include Additional Credit Ratio Amortizations which were assigned to specific reserve plant accounts in each jurisdiction differently and therefore are assigned directly to the applicable jurisdiction. In addition, Kansas unrecovered reserve amounts are allocated directly to Kansas.

Working Capital

Cash working capital ("CWC") is not allocated. Instead, the CWC amounts are calculated in the Revenue Requirement Model by taking the net CWC factors and applying these factors to allocated jurisdictional amounts in the Revenue Requirement Model. Fuel inventory is allocated using the Energy allocator. Materials and supplies ("M&S") and prepayments are grouped by function and allocated based on allocations appropriate for the function of the M&S and prepayments.

Regulatory Assets and Regulatory Liabilities

Regulatory assets and regulatory liabilities are assigned directly to the applicable jurisdiction except for Nuclear PTC which is allocated based on the Energy Allocator.

Accumulated Reserve for Deferred Taxes

Plant related reserve not directly assignable to a jurisdiction are primarily allocated based on Demand. There is one exception, Nuclear Fuel is allocated by Energy. Non-Plant related reserve not directly assignable to a jurisdiction are grouped by the type of allocation to which the temporary differences relate to. Deferred tax reserve amounts that are associated with regulatory assets and liabilities are assigned directly to the applicable jurisdiction.

Customer Advances for Construction and Customer Deposits

Customer advances for construction and customer deposits are assigned directly to the applicable jurisdiction.