Exhibit No.:	
Issue(s):	Revenue Requirement; NBEC; Cash Working Capital
Witness:	Stephen J. Hipkiss
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2024-0319
Date Testimony Prepared:	June 28, 2024

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2024-0319

DIRECT TESTIMONY

OF

STEPHEN J. HIPKISS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
June, 2024

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DIRECT TESTIMONY

OF

STEPHEN J. HIPKISS

FILE NO. ER-2024-0319

I. INTRODUCTION

Q. Please state your name and business address.

A. Stephen J. Hipkiss, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Missouri?

A. I am employed by Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company") as Senior Manager, Regulatory Accounting.

Q. Please describe your educational background and employment experience.

A. I received a Bachelor of Science in Accounting and Finance from Truman State University in 2010 and a Master's in Accounting from Truman State University in 2011. I am a Certified Public Accountant (CPA), licensed to practice in the state of Missouri. From 2011 to 2014, I worked for Ernst and Young LLP in its assurance practice, first as an Audit Staff and then as an Audit Senior. From 2014 to 2016, I worked for SunEdison, Inc., a solar and wind energy developer and operator, in its Financial Reporting group, first as a Senior Accountant and then as a Manager. From 2016 to April 2024, I worked for Ameren Services Company, first as a Supervisor and then as a Manager in the Accounting Research, Policy, and Internal Controls group. My primary duties and responsibilities included accounting analyses for non-standard transactions, overseeing the implementation of new accounting guidance, the implementation of new accounting policies, and assessments of the internal control environment. From May 2024 to present, I have been working for Ameren Missouri as Senior Manager, Regulatory Accounting.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to develop the revenue requirement (cost of service) for the electric operations of Ameren Missouri. The revenue requirement determines the level of electric revenues required to pay operating expenses, provide for depreciation and taxes, and give investors an opportunity to earn a fair and reasonable return on their investment. Company witness Thomas Hickman uses this data as the starting point for his class cost of service study. In addition, I will provide testimony on the calculation of net base energy costs, which are used in the formula appearing in the Company's fuel adjustment clause ("FAC", i.e., Rider FAC), as well as the rate values reflected in the FAC, i.e., the summer and winter values for Factor BF as defined in the FAC tariff. Finally, I discuss the lead/lag study prepared for the Company's electric business that I used to develop cash working capital ("CWC") factors. The CWC factors were used to calculate the Company's cash working capital requirements included in the revenue requirement.

Q. Are you sponsoring any schedules?

A. Yes. I am sponsoring Schedules SJH-D1 through SJH-D18.

Q. What is the subject matter of these schedules?

A. Schedules SJH-D1 through SJH-D16 develop the various elements of the revenue requirement to be considered in arriving at the proper level of rates for the Company's electric service based on the test year of the twelve months ended March 31, 2024, with pro forma adjustments and updates for known and measurable changes to be trued-up through December 31, 2024. Schedule SJH-D17 reflects the calculation of net base energy costs ("NBEC") and the seasonal values for Factor BF in Rider FAC. Schedule SJH-D18 reflects the results of the cash working capital lead/lag study prepared as of the twelve months ended December 31, 2020.

Q. Will you please briefly summarize the information provided on each of the schedules you are presenting?

A. Each schedule provides the following information:

- Schedule SJH-D1 – Original Cost of Electric Plant by functional classification at March 31, 2024, per book and pro forma.
- Schedule SJH-D2 – Electric Plant Reserves for Depreciation and Amortization by functional classification at March 31, 2024, per book and pro forma.
- Schedule SJH-D3 – Average Fuel Inventories and Average Materials and Supplies Inventories at March 31, 2024, per book and pro forma applicable to electric operations.
- Schedule SJH-D4 – Average Prepayments at March 31, 2024, per book and pro forma applicable to electric operations.

- Schedule SJH-D5 – Total Electric Cash Working Capital (per the Company's lead/lag study) for the twelve months ended March 31, 2024, applicable to electric operations.
- Schedule SJH-D6 – Interest Expense Cash Requirement, Federal Income Tax Cash Requirement, State Income Tax Cash Requirement, and City of St. Louis Earnings Tax Cash Requirement applicable to electric operations (per the Company's lead/lag study) for the twelve months ended March 31, 2024.
- Schedule SJH-D7 – Average Electric Customer Advances for Construction and Average Electric Customer Deposit reductions to rate base at March 31, 2024.
- Schedule SJH-D8 – Regulatory Asset and Liability balances included in rate base at March 31, 2024, per book and pro forma.
- Schedule SJH-D9 – Total Electric Accumulated Deferred Income Taxes at March 31, 2024, per book and pro forma.
- Schedule SJH-D10 – Total Electric Operating Revenues for the twelve months ended March 31, 2024, per book and pro forma.
- Schedule SJH-D11 – Total Electric Operations and Maintenance Expenses, by functional classification, for the twelve months ended March 31, 2024, updated for certain known items, per book and pro forma. A description of each pro forma adjustment is included.
- Schedule SJH-D12 – Depreciation and Amortization Expenses applicable to electric operations, by functional classification, for the

twelve months ended March 31, 2024, per book and pro forma. A description of each pro forma adjustment is included.

- Schedule SJH-D13 – Taxes Other Than Income Taxes, for the twelve months ended March 31, 2024, per book and pro forma for the electric operations of the Company. A description of each pro forma adjustment is included.
- Schedule SJH-D14 – Income Tax Calculation at the proposed rate of return and statutory tax rates for the total electric operations of the Company.
- Schedule SJH-D15 – The pro forma Electric Net Original Cost Rate Base at March 31, 2024, and Electric Revenue Requirement including the pro forma adjustments.
- Schedule SJH-D16 – The annual revenue increase required at a 7.398% return on Net Original Cost Electric Rate Base, including pro forma adjustments.
- Schedule SJH-D17 – Calculation of NBEC and seasonal values of Factor BF in Rider FAC.
- Schedule SJH-D18 – Cash Working Capital Factors.

III. REVENUE REQUIREMENT

Q. What do you mean by "revenue requirement"?

A. The revenue requirement of a utility company is the sum of operations and maintenance expenses, depreciation and amortization expenses, taxes, and a fair and reasonable return on the net value of property used and useful in serving its customers (and other rate base amounts). The revenue requirement is based on a test year, and it is necessary to make certain pro forma adjustments in order to reflect conditions existing at the end of the trued-up test year, as well as significant changes that are known or reasonably certain to occur closer to when new rates would take effect.

The revenue requirement represents the total funds (revenues) that must be collected by the Company if it is to pay employees and suppliers, satisfy tax liabilities, and provide a fair return to investors. To the extent that current revenues are less than the revenue requirement, as is true in this case, a rate increase is required.

Q. What test year is the Company proposing to use to establish the revenue requirement in this proceeding?

A. The Company is proposing a test year consisting of the twelve months ending March 31, 2024 ("test year"), with pro forma adjustments to account for the true-up of various items through December 31, 2024 ("true-up date"), consistent with the approach used in the Company's approximately ten previous rate reviews. The Company is proposing to true-up the following items: plant-in-service, depreciation reserve, materials and supplies (including fuel inventories), prepayments, cash working capital (excluding CWC factors), customer advances for construction, customer deposits, accumulated deferred income taxes, pension and other post-employment benefits ("OPEB"), tracked regulatory asset/liability balances, customer growth revenues, MEEIA revenues, behind the meter solar revenues, net energy costs (as defined in Rider FAC), payroll, employment levels, other employee benefits, Renewable Energy Standard ("RES") costs, bad debt expense, Callaway re-fueling expenses, steam plant maintenance, storm costs, vegetation maintenance, infrastructure inspection expenses, software maintenance, cybersecurity expenses, Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") costs, insurance expenses, Pay as You Save ("PAYS") amounts, the Missouri Public Service Commission ("MPSC") assessment, operations and maintenance costs resulting from new solar energy centers, capital structure, capital costs, depreciation expense, income taxes, non-income taxes and various amortization amounts (such as the pension & OPEB tracker amortization). The Company will also true-up coal prices, Midcontinent Independent System Operator, Inc. ("MISO") transmission revenues and expenses, and any wage increases that become effective on or before January 1, 2025. Finally, the Company proposes that other significant items that may arise through the true-up date, both increases and decreases, should be trued-up through December 31, 2024.

Q. Why is it necessary to make pro forma adjustments to the test year data and to true-up certain revenue requirement components?

A. In ratemaking, rates are set for the future. It is often necessary to adjust the test year data to be more representative of future operating conditions. Pro forma adjustments allow for the newly-authorized rates to have the opportunity to produce the allowed rate of return during the period they are in effect. This requires pro forma adjustments to reflect known and measurable changes from historical test year levels.

Q. Has the Company made any pro forma adjustments related to the Rush Island Energy Center as a result of its securitization application in File No. EF-2024-0021?

A. Yes. The Company's revenue requirement reflects the Company's positions in File No. EF-2024-0021 ("Securitization"), assuming an October 15, 2024, retirement date for Rush Island Energy Center ("Rush Island"). To acknowledge the intersection of securitization and this revenue requirement, the Company made certain adjustments in plant, accumulated depreciation reserve, materials and supplies, and accumulated deferred income taxes ("ADIT") to eliminate all balances related to Rush Island. Doing so reduces the revenue requirement in this case by approximately $78 million.[1] The Company will reflect the outcome of the Rush Island Securitization case in its true-up revenue requirement.[2]

Q. Please explain Schedule SJH-D1.

A. Schedule SJH-D1 shows the recorded original cost of electric plant by functional classification at March 31, 2024, along with the estimated plant additions and other adjustments through December 31, 2024, which is the end of the Company's proposed true-up period. The Company's plant accounts are recorded on the basis of original cost as defined by the Uniform System of Accounts and prescribed by the MPSC.

Q. Please explain the elimination of the plant balances related to the Accounting Standards Codification ("ASC") 410-20 *Asset Retirement Obligations* ("ARO") and the ASC 842 *Leases* shown as the first adjustment on Schedule SJH-D1.

A. An ARO is a legal obligation associated with the retirement of a tangible, long-lived asset that results from the acquisition, construction, development, and/or normal operation of that asset. ASC 410-20[3] requires the Company to record both an asset and a corresponding liability for such asset retirement costs. ASC 842 is an accounting

[1] Please see File No. EF-2024-0021, *Initial Post-Hearing Brief of Union Electric Company d/b/a Ameren Missouri*, p. 54, filed May 10, 2024.
[2] Given this case's filing schedule, the revenue requirement could not account for the precise rulings of the Commission on all issues in File No. EF-2024-0021.
[3] ASC 410-20 superseded Financial Accounting Standard ("FAS") 143, *Asset Retirement Obligations*.

requirement that leases are recorded on the balance sheet in the form of an asset, and an equivalent offsetting liability. Adjustment 1 to plant, in the amount of ($256,887,000) eliminates both the ARO and lease assets for ratemaking purposes.

Q. Why is the Company including plant additions through December 31, 2024?

A. Consistent with its plans submitted to the MPSC, the Company continues to invest in infrastructure upgrades and replacements throughout its service territory under its Smart Energy Plan. Company witness Warren Wood highlights some of the important projects under the Smart Energy Plan in his direct testimony. In order to provide the Company with an opportunity to earn a fair and reasonable return on its total investment, it is necessary for the cost of service to reflect, as closely as possible, the level of the Company's investment that exists at the time new rates become effective. Adjustment 2 adds the estimated plant-in-service additions, offset by retirements, of $2,553,423,000 from March 31, 2024, through December 31, 2024, which is the end of the proposed true-up period.

Q. Please explain the adjustment for the Rush Island Energy Center.

A. Adjustment 3 reduces the plant-in-service by $877,424,000 to reflect the retirement of Rush Island.[4]

Q. Please explain the elimination of items in General and Intangible Plant applicable to gas operations.

A. General and Intangible Plant assets, such as general office buildings, the central warehouse, the central garage, software, computers, and office equipment, are used

[4] The Company's revenue requirement also reflects the transfer of certain Rush Island assets to other energy centers, as proposed in File No. EF-2024-0021.

in both the electric and gas operations. For convenience, such investments are presented as electric plant in our accounting records. Adjustment 4 eliminates the portion of the multi-use General Plant and Intangible Plant allocated to the Company's gas operations of $29,010,000 and $39,297,000, respectively.

Q. Please explain the reduction to electric plant-in-service for incentive compensation.

A. In past Ameren Missouri rate reviews, a portion of the Company's incentive compensation paid has either been disallowed or was not requested for recovery by the Company. Within the accounting records of the Company, a portion of that compensation was capitalized and added to plant-in-service. Adjustment 5 reduces the plant-in-service balance by $59,877,000 for the accumulated amount of any previously disallowed and/or not requested capitalized incentive compensation.

Q. After reflecting the above pro forma adjustments, what amount of electric plant-in-service is the Company proposing to include in rate base?

A. As shown in Schedule SJH-D1, the total electric plant-in-service is $25,703,855,000.

Q. What pro forma adjustments were made to the accumulated reserve for depreciation on Schedule SJH-D2?

A. Similar adjustments were made to the accumulated reserve balance of plant-in-service. Adjustment 1 eliminates $89,440,000 from the depreciation reserve related to ASC 410-20 *ARO* and ASC 842 *Leases*.

Adjustment 2 increases the depreciation reserve by $553,719,000 to reflect depreciation through the true-up date on plant-in-service investments existing at March 31, 2024.

Adjustment 3 increases the depreciation reserve by $22,769,000 to reflect the depreciation related to pro forma net additions to plant-in-service from March 31, 2024, through December 31, 2024, the proposed true-up period. Incremental reserve on most pro forma net additions is calculated by multiplying the monthly depreciation rate by one-half the number of months in the true-up period in order to reflect the additions being placed in service ratably over the period. However, due to the size and nature of the three utility scale solar energy centers scheduled to be placed in service by December of 2024, the reserve for these additions is instead calculated as one-half month of depreciation to better reflect the depreciation the Company will experience on these three investments in the true-up period.

Adjustment 4 reduces the depreciation reserve by $425,243,000 for the retirement of Rush Island.[5]

Adjustment 5 eliminates the accumulated depreciation reserve of $7,728,000 for the multi-use General Plant applicable to gas operations and the accumulated amortization of $21,163,000 for Intangible Plant applicable to gas operations. This adjustment corresponds to Adjustment 4 made to plant-in-service on Schedule SJH-D1.

Accumulated depreciation and amortization reserve is reduced by $19,673,000 in Adjustment 6 to reflect the accumulated depreciation and amortization applicable to a

[5] The Company's revenue requirement also reflects the transfer of certain Rush Island assets, along with the related depreciation reserves, to other energy centers, as proposed in File No. EF-2024-0021.

portion of capitalized incentive compensation reflected in Adjustment 5 in Schedule SJH-D1.

The pro forma accumulated provision for depreciation and amortization, as shown in Schedule SJH-D2, applicable to total plant-in-service is $9,946,209,000.

Q. Please explain Schedule SJH-D3.

A. Schedule SJH-D3 shows the average investment in fuel inventories and materials and supplies inventories at March 31, 2024. Fuel inventory consists of nuclear fuel, coal, minor amounts of oil and stored natural gas used for electric generation, emissions allowances, and renewable energy credits ("RECs"). The nuclear fuel balances include the nuclear fuel in the reactor as well as the nuclear fuel on site at the Callaway Energy Center. General materials and supplies inventory includes items such as poles, cross arms, wire, cable, line hardware, and general supplies. A thirteen-month average is used for all these items, except nuclear fuel. An eighteen-month average is used for the nuclear fuel since the Callaway Energy Center is re-fueled every eighteen months.

Adjustment 1 shown in Schedule SJH-D3 reduces coal inventory included in rate base by $15,400,000 to remove Rush Island coal inventories and to adjust the thirteen-month average inventory levels to January 2025 coal prices.

Adjustment 2 shown in Schedule SJH-D3 reduces general materials and supplies included in rate base by $18,304,000 for the retirement of Rush Island.

Adjustment 3 shown in Schedule SJH-D3 reduces general materials and supplies included in rate base by $2,344,000 for the portion of the average general materials and supplies inventory applicable to the Company's gas operations.

Q. What is the amount of pro forma materials and supplies applicable to electric operations?

A. The pro forma materials and supplies applicable to total electric operations, as shown in Schedule SJH-D3, is $605,957,000.

Q. Please explain the average prepayments shown in Schedule SJH-D4.

A. Certain costs for items such as rent, insurance, medical and dental voluntary employee beneficiary association ("VEBA") contributions, memberships, and service agreements related to software maintenance are paid in advance. The prepaid software maintenance agreements are paid for initially by Ameren Service Company ("AMS"), and then AMS bills the Company for its portion of the prepaid asset. The Company settles its intercompany billings with AMS monthly. After elimination of amounts applicable to gas operations, the thirteen-month average balance of total electric prepayments at March 31, 2024, is $27,835,000.

Q. Please explain Schedule SJH-D5.

A. Schedule SJH-D5 shows the calculation of the electric cash working capital requirement as a negative net cash requirement of ($22,233,000), which is based on a lead/lag study for the twelve months ended December 31, 2020, and including pro forma adjustments to operating expenses. I will explain the details of the lead/lag study later in this testimony.

Q. What appears on Schedule SJH-D6?

A. The interest expense, federal income tax, state income tax, and St. Louis City earnings tax cash requirements applicable to the Company’s electric operations (per the Company's lead/lag study) are shown in Schedule SJH-D6. The payment lead times for these items are based on actual or statutory due dates. I will explain the details of the lead/lag study later in this testimony.

Q. What is the cash requirement for interest expense, federal income taxes, state income taxes and St. Louis City earnings tax?

A. Reflecting the payment lead times for each of these items compared to the revenue lag results in negative cash requirements of ($42,702,000) for interest expense, ($202,000) for federal income taxes, ($79,000) for state income taxes, and ($68,000) for St. Louis City earnings tax.

Q. What items are shown in Schedule SJH-D7?

A. The thirteen-month average balances at March 31, 2024, for electric customer advances for construction and electric customer deposits are shown in Schedule SJH-D7. These items represent cash provided by customers that can be used by the Company until they are refunded. Therefore, the average balances for customer advances for construction and customer deposits are reductions to the Company's rate base.

Customer advances for construction are cash advances made by customers that are subject to refund to the customers in whole or in part. These advances provide the Company cash that offsets the cost of the construction until they are refunded. The thirteen-month average balance of electric customer advances for construction was $1,537,000 at March 31, 2024.

Customer deposits are cash deposits made by customers, which are subject to refund to the customer if the customer develops a good payment record. The Company pays interest on the deposits, which is shown as a customer accounts expense in Schedule

SJH-D11. The thirteen-month average balance of electric customer deposits was $29,356,000 at March 31, 2024.

Q. What is shown in Schedule SJH-D8?

A. Schedule SJH-D8 shows regulatory assets and liability balances included in rate base, including the pension and OPEB regulatory liability balances, the PAYS regulatory asset, the plant-in-service accounting ("PISA") regulatory asset, the Meramec Energy Center ("Meramec") retirement regulatory asset, a regulatory liability for expired & expiring amortizations, and the property tax tracker regulatory asset balance.

The pension and OPEB regulatory liability balances of $60,210,000 and $17,453,000, respectively, reflect amortization of the tracked balances established in File No. ER-2022-0337 through the true-up date and accumulation through the true-up date for the current accumulation period. The Company proposes that the remaining balances as of the true-up date for all pension and OPEB deferrals established prior to File No. ER-2022-0337 be combined into the expired & expiring amortizations regulatory liability included in rate base and to be amortized as part of the expired & expiring amortizations discussed in Adjustment 11 on Schedule SJH-D12. Additionally, the Company proposes to refund the remaining regulatory liability balance from File No. ER-2022-0337 over 2 years and the most recent accumulation period, from January 1, 2023, through the true-up date, over a period of 5 years, consistent with the approach agreed to and approved in File No. ER-2022-0337.

In the Unanimous Stipulation and Agreement in File No. EO-2018-0211, the Company agreed to include the PAYS regulatory asset in rate base in future rate reviews.

The $1,710,000 PAYS regulatory asset reflects the total deferrals made under the PAYS program less any amortization recorded, or expected to be recorded by the true-up date.

Schedule SJH-D8 also includes the PISA regulatory asset balance included in rate base. PISA is the name commonly given to the deferrals of 85% of the depreciation expense and return on "qualifying electric plant" as required by Section 393.1400 RSMo., under legislation adopted by the Missouri General Assembly in 2018 and amended in 2022. The total PISA regulatory asset balance of $611,655,000 reflects the deferral made, and estimated, under PISA on or after September 1, 2018, through the true-up date, net of amortization. The statute also provides that in each general rate proceeding, the balance of the PISA regulatory asset as of the rate base cutoff date (i.e., December 31, 2024) shall be included in the participating utility's rate base.

The Meramec retirement regulatory asset is comprised of three components. The first component was established in the Unanimous Stipulation and Agreement from File No. ER-2021-0240. The amount represents an agreed upon amount of non-labor operating costs associated with the normal operations, not including post-closure costs, of the Meramec Energy Center through its retirement. The second component is the Meramec materials and supplies inventory write-off that was established in ER-2022-0337, plus an additional $3,444,000 of write-offs that have occurred since, resulting from the final disposal of inventory. The third component of this asset includes $310,000 for Meramec basemat coal inventory. This amount represents the remaining balance of coal inventory at Meramec after all coal transfers from Meramec to other energy centers were completed. The costs giving rise to the Meramec retirement regulatory asset are the Company's remaining unrecovered rate base investments. Accordingly, the $33,512,000 remaining unrecovered balance as of the true-up date is included in rate base.

Beginning with the Unanimous Stipulation and Agreement in File No. ER-2016-0179, the Company has combined and netted the true-up date balances of regulatory assets and liabilities that have expired (and over-amortized) since the Company's last rate review or are expected to expire soon after the true-up date. Any over- or under-recovery of a regulatory asset/liability is treated in the same manner as the underlying regulatory asset/liability, meaning that if the underlying regulatory asset/liability was included in rate base the over-/under-recovery shall also be included in rate base, but if the underlying regulatory asset/liability was not included in rate base neither shall the over-/under-recovery be. The Company proposes to continue that approach in this case.

In accordance with this approach, a regulatory liability of $1,830,000 decreases the Company's rate base for the combined effect of regulatory assets and liabilities that were previously included in rate base, but which will expire prior to the true-up date in this case (or soon after). The combined over or under-recovery of such regulatory assets and liabilities expected through December 31, 2024, has also been included in this adjustment. Refer to Adjustment 11 from the discussion of Schedule SJH-D12 below for the inventory of regulatory assets and liabilities that are expected to expire prior to the true-up date in this case (or soon after) and, therefore, have been combined.[6]

In the Stipulation and Agreement in File No. ER-2022-0337, an electric property tax tracker was memorialized with a base amount of $161,446,770. Line 7 of Schedule SJH-D8 includes a $23,509,000 property tax tracker regulatory asset balance, representing

[6] As proposed by Staff and agreed to by the Company in File No. ER-2022-0337, the Company has measured this regulatory liability balance (as well as other amortizations) as of the true-up date in this case.

actual and estimated deferrals (expense levels above the established base amount) under the property tax tracker through the true-up date. In this case, the Company proposes to set the base level for the property tax tracker at $171,241,000.

Q. Please explain Schedule SJH-D9.

A. Schedule SJH-D9 lists the ADIT applicable to total electric operations at March 31, 2024, and the pro forma adjustments required to project the balances forward to December 31, 2024, the end of the proposed true-up period. ADIT is the net result of normalizing the tax benefits resulting from timing differences between the periods in which transactions affect taxable income and the period in which such transactions affect the determination of pre-tax income.

Currently, the Company has deferred income taxes in Federal Energy Regulatory Commission ("FERC") Accounts 190, 281, 282, and 283. As shown in Schedule SJH-D9, the total electric pro forma ADIT balance is a net liability balance of $2,862,799,000. Net deferred income tax liabilities are a deduction from rate base.

Q. What is the Company's pro forma net original cost electric rate base at December 31, 2024?

A. The Company's total electric rate base as shown in Schedule SJH-D15 is $14,023,355,000.

Q. Please explain Schedule SJH-D10.

A. Schedule SJH-D10 shows total electric operating revenues per book and pro forma for the twelve months ended March 31, 2024, with customer growth and other pro forma adjustments through December 31, 2024, the end of the proposed true-up period.

Q. Please explain the pro forma adjustments to the electric operating revenues shown in Schedule SJH-D10.

A. The following pro forma adjustments are shown in Schedule SJH-D10:

Adjustment 1 eliminates revenue add-on taxes of $159,576,000, as they are directly passed through to customers by the Company. Adjustment 2 eliminates the Missouri Energy Efficiency Investment Act ("MEEIA") revenues of $89,504,000, as they are collected through the MEEIA Rider rather than through base rates. Adjustment 3 eliminates FAC revenues of $134,839,000, as they are collected through the FAC Rider rather than base rates. Adjustment 4 eliminates the effect of unbilled revenues and increases revenues by $345,000. After the unbilled revenue adjustment, book revenues are reflected on a bill cycle basis. Because new retail rates (resulting from File No. ER-2022-0337) were effective July 9, 2023, Adjustment 5 increases revenues by $39,468,000 to annualize the effect of those new rates to the full test year. Adjustment 6 removes $8,226,000 of revenues as a result of the economic development incentive ("EDI") adjustment, an adjustment made to account for pro forma base rate revenues that will not otherwise be collected due to discounts on base rates granted under the Company's economic development incentive provisions under Rider No. 86 approved with Section 393.1640 RSMo. Adjustment 7 increases revenues by $5,871,000 to remove the EDI discounts provided during the test year. Adjustment 8 increases revenues by $1,623,000 to reflect revenues expected to be received as part of the Company’s Community Solar Program. Adjustment 9 increases revenues by $20,281,000 to reflect estimated customer growth through December 31, 2024. Adjustment 10 reduced revenues by $15,366,000 to remove revenues recovered under the RESRAM. To annualize the impact of energy efficiency efforts and customer-owned solar installations, most of which were incentivized through Company rebate programs, revenues are being reduced by $9,416,000 in Adjustment 11. Since the Company uses cycle and window billing, revenues are increased by $148,000 to reflect the twelve-month billing year as a twelve-month, 365-day, calendar year in Adjustment 12. Adjustment 13 increases revenues by $3,536,000 to synchronize the book revenues with the Company's billing unit rate analysis. Revenues were increased in Adjustment 14 by $20,541,000 to reflect normal weather. Adjustment 15 increases revenues by $7,037,000 to reflect revenues expected to be received as part of the Company's Renewable Solutions Program. Revenue adjustments 5, 6, 8, 9, 11, 12, 13, and 14 are further discussed by Company witness Nicholas Bowden in his direct testimony. Revenue adjustment 15 is further discussed by Company witness Steven Wills.

The provision for rate refunds of $4,323,000, applicable to the operation of the Company's FAC, is eliminated in Adjustment 16.

The "other electric revenues" in Schedule SJH-D10 were increased by $2,814,000 in Adjustment 17 for estimated transmission revenues through December 31, 2024, the proposed true-up date. Adjustment 18 increases revenue by $1,814,000 to reflect expected additional intercompany facility rental revenue. In Adjustment 19, the Company is decreasing software rental revenues by $794,000 because certain software assets will be fully amortized prior to the true-up date and therefore will no longer be a source of rental revenue. Adjustment 20 increases revenue by $16,000 for annual revenues expected at the true-up date under the PAYS program. Adjustment 21 eliminates revenue add-on taxes of $758,000 applicable to other revenues, as they are directly passed through to customers by the Company.

Q. Are the revenues from off-system energy sales included in Schedule SJH-D10?

A. Yes, Adjustment 23 in Schedule SJH-D10 increases the actual off-system sales revenues from energy by $170,377,000 to reflect a normal level of off-system sales calculated using the current normalized market price for energy and the annualized power and ancillary services market revenues from MISO, as discussed in the direct testimony of Company witness Andrew Meyer. Adjustment 24 increases sales of capacity by $258,385,000, to reflect a normal level of capacity sales, as is also addressed in Company witness Meyer's direct testimony. The production cost model ("PowerSIMM"), explained in the direct testimony of Company witness Mark Peters, was used to develop the normal off-system sales volumes and revenues from energy sales.

Q. What are the pro forma electric operating revenues for the twelve months ended December 31, 2024?

A. The pro forma electric operating revenues for the twelve months ended December 31, 2024, are $3,623,491,000, including the off-system sales revenues.

Q. Please describe what is shown in Schedule SJH-D11.

A. Total electric operating and maintenance ("O&M") expense for the twelve months ended March 31, 2024 (per books by functional classification), the pro forma electric operations and maintenance expenses by functional classification, and a listing of the pro forma adjustments are shown in Schedule SJH-D11.

Q. Please explain the pro forma adjustments to electric O&M expense for the twelve months ended March 31, 2024.

A. A summary of the pro forma adjustments to O&M expense appears in Schedule SJH-D11. Adjustment 1 reflects the increased labor expenses related to union and management wage increases at January 1, 2024, and January 1, 2025. A 3.5% wage increase for union employees was effective January 1, 2024, per the labor contracts. A 3.56% wage increase for management employees was effective January 1, 2024. In addition, the Company expects union and management employees to receive average wage increases of 3.1% effective January 1, 2025. The annualized increase in the total electric operating labor expense resulting from wage increases is $19,356,000. These wage increases reflect known and measurable changes that either have occurred or will occur subsequent to the test year. Incentive compensation was excluded from the calculation of the wage increases, as wage increases only apply to base wages.

Adjustment 2 reduces O&M expenses by $2,028,000 to eliminate the incentive compensation that is based on the achievement of earnings-per-share ("EPS") goals of the Company and, for the remaining incentive compensation not eliminated, adjust from expenses recognized to payments made under the plans during the test year.

Consistent with prior cases, Adjustment 3 reduces O&M expenses by $7,346,000 to eliminate the portion of long-term incentive compensation that is based on total shareholder return ("TSR")[7], including the allocated Ameren Services Company amount.

Adjustment 4 increases O&M expenses by $30,422,000 for an increase in fuel expense, while Adjustment 5 increases O&M by $247,070,000 for an increase in purchased

[7] TSR is a measure of how well a publicly traded company is performing financially. TSR measures returns from both changes in the Company's stock price and from the dividends it pays over any given period.

power expense. The increases to O&M expenses in Adjustments 4 and 5 were calculated by Company witness Peters using the PowerSIMM production cost model. His direct testimony details the inputs and assumptions used in the PowerSIMM production cost model. The purchased power expenses also include the power market and ancillary services changes from MISO.

Adjustment 6 reduces O&M expenses by $108,000 to reflect an adjustment ordered by the MPSC in its Report and Order in File No. EO-2011-0128, issued April 19, 2012, as modified by the Commission's Order Modifying Report and Order issued December 22, 2014. The referenced orders require that the Company make certain adjustments for ratemaking purposes for transmission charges from MISO for regionally allocated transmission facilities constructed by an Ameren Missouri affiliate in the service territory of Ameren Missouri. Ameren Missouri has received MISO transmission charges arising from one such project, the Mark Twain Transmission Project, and thus has adjusted its revenue requirement in this case for charges received on the project through March 31, 2024.

Adjustment 7 increases O&M expenses by $274,000 to normalize non-labor maintenance expenses over the Company's planned six-year maintenance cycle at the Labadie and Sioux Energy Centers. Given the six-year maintenance cycle, a specific test year is not representative of the normal maintenance expense levels incurred. Adjustment 7 reflects an adjustment of maintenance expenses to the six-year average of historical costs, which is consistent with the maintenance cycle at these plants.

Adjustment 8 decreases O&M expenses by $2,552,000 to adjust non-labor O&M expenses at the Rush Island Energy Center to expected amounts necessary for post-closure activities. Ongoing amounts include costs for physical security and landscaping (grass mowing).

Adjustment 9 decreases O&M expenses by $3,444,000 to adjust non-labor O&M expenses at the Meramec Energy Center to expected amounts necessary for post-closure activities. Ongoing amounts include costs for physical security and landscaping (grass mowing).

Adjustment 10 decreases O&M expenses by $50,958,000 to eliminate the FAC recovery during the test year, as these costs are recovered under the FAC Rider rather than base rates.

Adjustment 11 is an increase to O&M expenses to include two-thirds of the average of the last three Callaway Nuclear Energy Center re-fueling expenses. This adjustment is required because the outage cycle at the Callaway Nuclear Energy Center occurs every 18 months and the test year partially excluded the cost of a re-fueling outage, as related re-fueling costs are deferred and amortized in accordance with the Commission's Order in File No. EU-2020-0114. Therefore, in order to reflect an annualized amount of O&M expenses, it is necessary to include two-thirds (twelve-month annual period for setting rates as compared to the eighteen-month outage cycle) of Callaway Energy Center re-fueling expenses. Additionally, to address the variability in the level of expenses incurred during a refueling outage, this adjustment also reflects the normalization of costs by averaging the costs of the past three Callaway re-fueling outages. Production expenses must be increased by $24,760,000 for non-labor maintenance expense and $5,416,000 for incremental overtime expenses. Adjustment 11 results in a total increase of $30,176,0000.

Adjustment 12 is a decrease in O&M expenses of $34,133,000 to eliminate the Callaway Energy Center refueling amortization recorded in accordance with the Commission's order in File No. EU-2020-0114 from the test year. The net impact of adjustments 11 and 12 is a decrease in O&M expenses of $3,957,000.

Adjustment 13 decreases O&M expenses by $648,000 to eliminate amortization of the RES tracker regulatory balances established in prior cases and recover current accumulated costs over a three-year period. The remaining regulatory balances established in Files No. ER-2021-0240 and ER-2022-0337 as of the true-up date have been added to the expired & expiring amortizations discussed in Schedule SJH-D12.

Adjustment 14 decreases O&M expenses by $1,676,000 to re-base expenses related to the RES tracker, including the Maryland Heights Renewable Energy Center fuel costs.[8]

Adjustment 15 decreases O&M expenses by $1,338,000 to eliminate pre-RESRAM solar rebate costs and amortization from the test year. The balance established in File No. ER-2021-0240 has been added to the expired & expiring amortizations discussed in Schedule SJH-D12.

Adjustment 16 increases O&M expenses by $1,338,000 for an increase in depreciation that is charged to O&M for coal cars, transportation, and heavy-duty equipment. Depreciation expense charged to O&M was updated for investment levels at December 31, 2024, and depreciation rates proposed in this rate review.

[8] In this case, the Company proposes to set the base level for the RES tracker at $7,052,000.

Adjustment 17 decreases O&M expenses by $3,103,000 to normalize storm costs to reflect a five-year average. Variability exists in the level of storm costs experienced in any given test year. This normalization adjustment is consistent with past practice.

Adjustment 18 decreases O&M expenses by $5,450,000 to update vegetation management and infrastructure inspection expenses to the most recent levels expected in the proposed true-up period.

Adjustment 19 is an increase of $2,789,000 to O&M expenses to reflect interest expense at 9.5% on the thirteen-month average customer deposit balance as of March 31, 2024. The average customer deposit balance is deducted from rate base.

Adjustment 20 decreases O&M expenses by $71,459,000 to eliminate program costs related to MEEIA, which are included in the MEEIA Rider.

Adjustment 21 increases O&M expenses by $97,000 for the annual amortization of the PAYS regulatory assets expected at the true-up date. This adjustment includes annualization of the amortization authorized in Files No. ER-2021-0240 and ER-2022-0337 and amortization of incremental deferrals expected through the true-up date. The amortization period relating to the incremental deferrals will be calculated based on the remaining weighted useful life of measures installed under the program at the proposed true-up date.

Adjustment 22 increases O&M expenses by $2,075,000 to adjust bad debt expense to the level of bad debt net write-offs from the test year.

Adjustment 23 decreases O&M expenses by $581,000 to annualize salaries and benefits expenses based on staffing levels as of the end of the test year. This adjustment is consistent with the past practice of adjusting for the on-going employment levels experienced through the true-up date and allows for newly-authorized rates to most closely align with the Company's costs.

The various insurance policies of the Company are renewable at different times during a year. Adjustment 24 increases O&M expenses by $3,263,000 to annualize the premiums of the various insurance policies in effect, or expected to be in effect, at the time new rates are expected to be implemented in this case. In future testimony, the Company will further adjust O&M expenses to reflect the insurance premiums associated with the new solar facilities at the true-up date.

Adjustment 25 increases O&M expenses by $327,000 to reflect increases in the other employee benefits expense to annualize the employee benefits expense through the proposed true-up date.

O&M expenses are increased by $36,000 in Adjustment 26 to annualize the cost of the non-qualified pension plan, which is no longer in the pension tracker, to reflect the annualized calendar year 2024 level of expense.

Adjustment 27 decreases O&M expenses by $3,042,000 to rebase the pension and OPEB tracker to reflect applicable annualized calendar year 2024 expense levels.[9]

Adjustment 28 decreases O&M expenses by $8,433,000 to remove test year pension and OPEB tracker amortization, to amortize the remaining liability balances from File No. ER-2022-0337 as of the true-up date over 2 years, and to amortize the regulatory liability balance from the most recent accumulation period, from January 1, 2023, through the true-up date, over a period of 5 years. As discussed above in Schedule SJH-D8, the Company proposes that the remaining balances as of the true-up date for all pension and

[9] In this case, the Company proposes to set the base levels for the pension and OPEB trackers at ($65,948,000) and ($29,279,000), respectively.

OPEB tracker deferrals established prior to File No. ER-2022-0337 be combined into the expired & expiring amortizations regulatory liability included in rate base. Amortization of these remaining balances is included in the expired & expiring amortizations discussed in Schedule SJH-D12.

Adjustment 29 increases O&M expenses by $3,727,000 for non-labor O&M expenses included in the RESRAM base amount.[10] This rebasing adjustment reflects, in part, the expected annual O&M expenses at the Company's wind energy centers and the Huck Finn Renewable Energy Center as of the true-up date.

O&M expenses are increased in Adjustment 30 by $123,000 to reflect the average rate review expenses incurred by the Company in the last six general rate reviews and recovery of these costs over a two-year period.

Adjustment 31 increases O&M expenses by $183,000 to annualize the most recent Ameren Missouri electric operations MPSC assessment.

In Adjustment 32, the Company eliminated $566,000 of O&M expenses for certain Ameren Corporation Board of Directors chartered flight expenses.

Adjustment 33 increases O&M expenses by $4,874,000 to annualize the increase in building rent expense allocated to Ameren Missouri from Ameren Services Corporation and Ameren Illinois Transmission Company.

O&M expenses are increased in Adjustment 34 by $45,000 to reflect the average depreciation study expenses incurred by the Company in the last four depreciation studies (that coincide with the Company's last six rate reviews) and recovery of these costs over a two-year period.

[10] In this case, the Company proposes to set the base amount for the RESRAM at ($10,741,000).

Adjustment 35 decreases O&M expenses by $817,000 to annualize applicable expenses based on current allocation factors.

Adjustment 36 decreases O&M expenses by $1,358,000 to annualize the net reduction in meter reading costs based on expected progress in the Company's advanced metering infrastructure ("AMI") deployment at December 31, 2024.

Adjustment 37 increases O&M expenses by $35,000 for identified electric costs which were allocated to gas operations in the test year.

Adjustment 38 increases O&M expenses by $283,000 for customer convenience charges (e.g., credit card fees) that are included in the Company's revenue requirement in accordance with File No. ER-2021-0240. This adjustment reflects a thirteen-month average ending March 31, 2024 at the most recent fee rates.

During the test year, the Company recorded a net credit to O&M expenses of $5,695,000 to transfer certain preliminary survey and investigation charges related to solar energy center development projects to a balance sheet account for projects that have received a certificate of convenience and necessity ("CCN"), as these costs will be capitalized to utility plant when the related solar energy centers are placed in service. Adjustment 39 increases O&M expenses by $5,695,000 to eliminate the O&M impact from the transfer. Eliminating the O&M impact of the transfer is consistent with the Company's past practice of excluding such costs from its revenue requirement based on the expectation that these costs would eventually be capitalized to utility plant.[11]

[11] In the Company's most recent rate review (File No. ER-2022-0337), a pro forma adjustment was recorded to reduce O&M expenses by $3,434,000 to remove such preliminary survey and investigation charges related to solar energy center development projects recorded during the test year.

Adjustment 40 increases O&M expenses by $19,000 for expected annual cybersecurity costs through December 31, 2024, the proposed true-up period. Cybersecurity costs are generally expected to increase over time as the Company responds to an expanding threat landscape.

Adjustment 41 increases O&M expenses by $1,014,000 for expected annual software maintenance expenses through December 31, 2024, the proposed true-up period.

Adjustment 42 increases O&M expenses by $93,000 to annualize fees assessed by the Nuclear Regulatory Commission.

Adjustment 43 increases O&M expenses by $3,271,000 to include an annualized level of non-labor maintenance expense for the new Boomtown and Cass County solar energy centers scheduled to be placed in service by December 31, 2024, the proposed true-up period.

Adjustment 44 decreases O&M expenses by $689,000 to remove expenditures for the St. Louis Blues Power Play Goals for Kids campaign and other similar initiatives, in accordance with the Stipulation and Agreement in File No. ER-2021-0240.

Adjustment 45 decreases O&M expenses by $15,000,000 to remove the expense reserve associated with the Rush Island New Source Review ("NSR") litigation from the test year, because this litigation is ongoing and the ultimate outcome is not known and measurable at this time.

Adjustment 46 increases O&M expenses by $4,000 for electric vehicle incentive costs which were inappropriately allocated to gas operations in the test year.

Q. What is the impact on total electric operations and maintenance expense from the above pro forma adjustments?

A. As shown in Schedule SJH-D11, the total electric O&M expenses are increased from $1,707,058,000 to $1,848,939,000, or a total net increase of $141,881,000 by the above pro forma adjustments.

Q. What is shown in Schedule SJH-D12?

A. Schedule SJH-D12 shows the total electric depreciation and amortization expenses by functional classifications for the twelve months ended March 31, 2024, per book and pro forma through the true-up date.

Q. What pro forma adjustments apply to the depreciation and amortization expense?

A. Schedule SJH-D12 details the following pro forma adjustments to the depreciation and amortization expenses:

Adjustment 1 increases depreciation and plant amortization by $51,803,000 to reflect the book depreciation annualized for the plant-in-service depreciable balances at March 31, 2024, and plant additions through the true-up period, based on the depreciation rates approved in File No. ER-2022-0337.

Depreciation and plant amortization expenses are increased by $29,370,000 in Adjustment 2 to reflect the change in depreciation rates reflected in the depreciation study submitted in this case, which was conducted by Company witness John J. Spanos from Gannett Fleming Valuation and Rate Consultants, LLC.

Adjustment 3 increases depreciation and plant amortization by $42,247,000 to eliminate PISA depreciation and amortization deferrals from the test year ended March 31, 2024.

Depreciation for coal cars (Account 312), transportation equipment (Account 392), and heavy-duty equipment (Account 396) are charged to O&M rather than depreciation expense. Adjustment 4 reduces depreciation expense by $13,434,000 to remove the depreciation expense on these accounts.

Adjustment 5 decreases amortization expense by $3,687,000 to eliminate amortization of the Callaway Post Operational Regulatory Asset, which will expire in October 2024, before new rates are established in this case. The over amortized balance as of the true-up date has been included in the expired & expiring amortizations regulatory liability included in rate base, discussed earlier in Schedule SJH-D8, and will be amortized as part of Adjustment 11 discussed below.

Adjustment 6 decreases amortization expense by $93,000 to eliminate amortization of the Callaway Fukushima Study Costs regulatory asset. The remaining unamortized balance as of the true-up date will be amortized along with other expired & expiring regulatory balances as part of Adjustment 11 discussed below.

Adjustment 7 increases amortization expense by $369,000 to eliminate annual amortization of the construction accounting contra regulatory asset for the Sioux Scrubbers and to extend the amortization period of the construction accounting regulatory asset to reflect the updated 2032 retirement date for the Sioux Energy Center. The contra regulatory asset account is recorded for Generally Accepted Accounting Principles ("GAAP") purposes and has no impact on ratemaking.

Adjustment 8 increases amortization expense by $11,431,000 to reflect annualization of the amortization of costs for a study of customer affordability opportunities and eliminate the set-up of the regulatory asset that occurred in the test year. This regulatory asset and associated amortization were approved in File No. ER-2022-0337.

Adjustment 9 increases amortization by $7,177,000 to eliminate MEEIA deferrals and amortizations that are considered under the MEEIA Rider, including MEEIA ordered adjustments.

Adjustment 10 increases amortization expense by $31,000 to annualize the $2,125,000 above-the-line spend for the Keeping Current and Keeping Cool Program. This adjustment reflects a continuation of the $4,250,000 funding level agreed to and approved in File No. ER-2022-0337, split evenly between customers and the Company.

As previously referenced, the Company has combined and netted the true-up date balances of regulatory assets and liabilities that have expired (and over-amortized) since the Company's last rate review or are expected to expire soon after the true-up date. Any over or under-recovery that will exist as of the true-up date will be tracked, combined, and netted for the following balances:

Balance Description	December 31, 2024 Balance (Projected)
Expired & Expiring Amortizations per ER-2022-0337 – Rate Base	$43,000
Property Tax Tracker ER-2022-0337 – Rate Base	$561,000
Pension Tracker (tranches prior to ER-2022-0337) – Rate Base	$(1,305,000)
OPEB Tracker (tranches prior to ER-2022-0337) – Rate Base	$(515,000)
Callaway Post Operations Regulatory Asset – Rate Base	$(615,000)
Expired & Expiring Amortizations per ER-2022-0337 – Non-Rate Base	$3,439,000
RES Tracker ER-2021-0240 – Non-Rate Base	$(61,000)
RES Tracker ER-2022-0337 – Non-Rate Base	$550,000
Solar Rebate Program ER-2021-0240 – Non-Rate Base	$224,000
Fukushima Study Costs ER-2014-0258 – Non-Rate Base	$39,000
Excess Deferred Tax Tracker ER-2021-0240 – Non-Rate Base	$(560,000)
Excess Deferred Tax Tracker ER-2022-0337 – Non-Rate Base	$(4,582,000)
Total over-recovery	$(2,782,000)

These tracked, combined, and netted balances will be amortized over a three-year period. Adjustment 11 increases amortization by $2,976,000 to amortize the combined and netted over- and under-collections associated with expired & expiring regulatory asset and liability balances and to remove test year amortization associated with the expired & expiring regulatory asset and liability balances established in File No. ER-2022-0337.

Adjustment 12 increases amortization by $33,282,000 for the amortization of PISA deferrals over twenty-year periods.

Adjustment 13 increases amortization by $16,639,000 to eliminate amortization of the excess deferred tax tracker regulatory liability balances established in prior cases, eliminate test year deferrals, and amortize the current accumulation period balance over a three-year period.[12] The remaining unamortized regulatory liability balances established in Files No. ER-2021-0240 and ER-2022-0337 as of the true-up date have been added to the expired & expiring amortizations discussed in Adjustment 11 above.

Adjustment 14 increases amortization by $41,981,000 to eliminate deferrals made under the RESRAM and eliminate amortization associated with amounts recovered through the associated RESRAM rider.

Adjustment 15 increases amortization by $373,000 to recover the Charge Ahead Corridor Program regulatory asset over a seven-year period.

Adjustment 16 increases amortization by $1,256,000 to reflect amortization of the remaining unamortized costs associated with the issuance of equity for the funding of the High Prairie and Atchison renewable energy centers over a period of 5 years.

Adjustment 17 increases amortization by $9,468,000 to eliminate accumulation and reflect annualized amortization of Meramec materials and supplies inventory costs over the remaining 5-year period ending in June 2028, as established in File No. ER-2022-0337. Additionally, this includes the amortization related to a $3,444,000 write-off of Meramec materials and supplies inventory that occurred since the previous case, as discussed in SJH-D8.

Adjustment 18 increases amortization by $89,000 to reflect annualized amortization of Meramec basemat coal inventory over the same remaining 5-year period

[12] In this case, the Company proposes to set the base level for the excess deferred tax tracker at ($39,196,000), grossed up.

ending in June 2028 established for the Meramec materials and supplies inventory established in File No. ER-2022-0337.

Adjustment 19 increases amortization by $761,000 to recover the COVID-19 Accounting Authority Order deferral over the remaining 5-year period established in File No. ER-2021-0240.

Adjustment 20 increases amortization by $7,836,000 to recover property tax tracker deferrals over a period of 3 years.

Adjustment 21 increases amortization by $8,000 to recover heat pump rebate costs for the Kersting Estates over a period of 2 years, as discussed in the direct testimony of Company witness Laura Moore.

Q. What are the total electric pro forma depreciation and amortization expenses?

A. As reported in Schedule SJH-D12, the total electric pro forma depreciation and amortization expenses are $974,089,000.

Q. Please explain Schedule SJH-D13.

A. Schedule SJH-D13 shows taxes other than income taxes for the twelve months ended March 31, 2024, per book and pro forma.

Q. Please list the pro forma adjustments required to arrive at the total electric pro forma taxes other than income taxes as detailed in Schedule SJH-D13.

A. The following pro forma adjustments detailed in Schedule SJH-D13 are required to arrive at the total electric pro forma taxes other than income taxes. Adjustment 1 increases Federal Insurance Contributions Act ("FICA") taxes by $1,103,000 to reflect pro forma wage adjustments.

Adjustment 2 increases property taxes by $5,575,000 to reflect property taxes expected to be paid in December 2024.

Property taxes of $443,000 applicable to plant held for future use are eliminated in Adjustment 3. This adjustment is required as the investment in plant held for future use is not currently serving customers.

Adjustment 4 adjusts taxes other than income taxes to remove Missouri gross receipts taxes of $159,622,000, as they are add-on taxes that are directly passed through to customers. The pro forma book revenues also reflect the removal of the add-on revenue taxes.

Q. What are the total electric pro forma taxes other than income taxes?

A. As reflected in Schedule SJH-D14, the total electric pro forma taxes other than income taxes are $201,167,000.

Q. What is shown in Schedule SJH-D14?

A. Schedule SJH-D14 shows the derivation of the income tax calculation at the requested 7.398% rate of return for total electric operations reflecting the statutory tax rates. Refer to the direct testimony of Company witness Darryl T. Sagel for the development of the 7.398% rate of return.

Q. As shown in Schedule SJH-D14, what are the income taxes at the requested rate of return for total electric operations?

A. Total current federal, state, and city earnings income taxes using the statutory tax rates at the requested rate of return are $104,934,000[13] for total electric

[13] Current income taxes reflect a reduction of $79 million for Production Tax Credits ("PTCs") relating to the High Prairie, Atchison, and Huck Finn renewable energy centers, which are subject to the RESRAM. Production levels used to calculate PTC amounts are those produced by Company witness Peters.

operations, as shown in Schedule SJH-D14. Amortization of both excess accumulated deferred income taxes and normalized investment tax credits for total electric operations of ($96,888,000)[14] are also shown in Schedule SJH-D14. Net current and deferred income taxes for electric operations included in the revenue requirement are $8,046,000.

Q. Over what period does the Company propose federal unprotected excess accumulated deferred income taxes are amortized in this case?

A. Two years. While the continuation of terms in stipulations and agreements from prior cases would result in approximately three and one-half years of remaining amortization, the Company proposes this amortization be advanced to conclude two years after new rates take effect in this case. The advancement of this amortization results in a reduction to the Company's revenue requirement of approximately $46 million. Although this topic is otherwise unrelated to the Boomtown and Cass County renewable energy centers, the Company takes this customer-focused position because, as discussed in the direct testimony of Company witness Wills, the benefits of Investment Tax Credits ("ITCs") that will result from these energy centers are not expected to materialize by the true-up date in this case. Advancing the amortization of excess deferred taxes in this manner to address affordability conceptually treats the Company's total pool of existing federal unprotected excess deferred income taxes and expected ITC-related tax benefits as somewhat fungible, but in doing so aligns the benefits that this total pool of tax attributes provides in terms of reduction of the revenue requirement today with the timing of the costs of Boomtown and Cass County being included in the revenue requirement, more accurately

[14] Included in this amount is the amortization of remaining federal unprotected excess accumulated deferred income taxes over two years.

reflecting the expected net costs of these solar facilities when giving consideration to the tax benefits that they specifically generate.

Q. Please explain Schedule SJH-D15.

A. Schedule SJH-D15 shows the total electric rate base of $14,023,355,000 and the total electric revenue requirement of $4,069,689,000 at the requested return of 7.398%.

Q. What does Schedule SJH-D16 reflect?

A. Schedule SJH-D16 compares the total electric revenue requirement of $4,069,689,000 with the total electric pro forma operating revenues under the present rates of $3,623,491,000, including off-system energy sales revenues. It shows that the revenue requirement is $446,198,000 more than the pro forma operating revenues at present rates. $4,069,689,000 is the amount of revenues used to set the rates filed in this case and is the level of revenues needed to provide the Company an opportunity to collect and recover its cost of service, including an opportunity to recover its cost of capital.

IV. DETERMINATION OF NET BASE ENERGY COSTS

Q. Did you determine the "net base energy costs" utilized in the Company's FAC, as addressed in the direct testimony of Company witness Meyer and Peters?

A. Yes. I calculated the net base energy costs and the seasonal values for Factor BF in Rider FAC for both the summer and winter, which are 1.304 cents per kilowatt-hour for the summer and 1.397 cents per kilowatt-hour for the winter. Schedule SJH-D17 shows the calculation of total net base energy costs, and the calculation of the Factor BF values for the summer and winter periods. The net base energy costs calculation starts with the fuel and purchased power costs determined by PowerSIMM, as discussed in Company witness Peters' direct testimony. There are other costs for fuel and purchased power that are not modeled by PowerSIMM, including net fly ash revenues and expenses, fixed gas supply costs, fuel additives, MISO Day 2 expenses, capacity expenses, replacement power insurance costs, Account 565 transmission expenses, the cost of purchasing ancillary services, and the cost of purchased power to serve common boundary customers. This total cost of fuel and purchased power is then offset or reduced by off-system energy sales revenues calculated via PowerSIMM. There are additional revenues not included in PowerSIMM, including the MISO Day 2 revenues, capacity sales, real-time load and generation deviation, and revenues from sales of ancillary services. All of the above expenses and revenues are then divided between the summer and winter periods to develop two separate values under Rider FAC. Per Schedule SJH-D17, the summer net base energy cost of $150,911,147 was then divided by the normalized Ameren Missouri summer load at the MISO Node AMMO.UE of 11,571,854,538 kWhs to arrive at a summer value expressed in cents per kWh of 1.304 cents. The winter net base energy cost of $290,995,649 was then divided by the normalized Ameren Missouri winter load at the MISO Node AMMO.UE of 20,831,556,789 kWhs to arrive at a winter value expressed in cents per kWh of 1.397 cents.

V. CASH WORKING CAPITAL ANALYSIS

Q. For what period was the cash working capital lead/lag study performed?

A. The lead/lag study analyzed the Company's cash transactions and invoices for the twelve months ending December 31, 2020. This study was utilized in Files No. ER-

2021-0240 and ER-2022-0337. This study is less than 5 years old and it remains appropriate to rely on this study in this rate review.

Q. Please define what you mean by the phrase "cash working capital."

A. Cash working capital is the amount of funds required to finance the day-to-day operations of the Company.

Q. What is a lead/lag study?

A. A lead/lag study is an analysis of revenue lags and expense leads. CWC requirements are generally determined by lead/lag studies that are used to analyze the lag time between the date customers receive service and the date that customers' payments are available to the Company (i.e., the revenue lag). This lag is offset by a lead time during which the Company receives goods and services but pays for them at a later date (i.e., the expense lead). The "lead" and "lag" are both measured in days. The dollar-weighted lead and lag days are then divided by 365 to determine a daily CWC factor. This CWC factor is then multiplied by the annual test year cash expenses to determine the amount of cash working capital required for operations. The resulting amount of cash working capital is then included in the Company's rate base.

Q. Please explain the revenue lag in more detail.

A. As noted, the revenue lag refers to the elapsed time between the delivery of the Company's product (i.e., electricity) and its ability to use the funds received as payment for the delivery of the product. The revenue lag actually consists of three components as follows: the service lag, which is the number of days from the mid-point of the service period to the meter reading date; the billing lag, which is the time between when the meter is read and the bill is sent; and the collections lag, which is the time between when the bill is sent to the customer and when the customer's payment is received by the Company.

Q. Please explain the expense lead in more detail.

A. An expense lead refers to the elapsed time from when a good or service is provided to the Company to the point in time when the Company pays for the good or service and the funds are no longer available to the Company. There are a number of different expense leads, since the Company acquires goods and services from a number of different sources.

Q. What sources of information are employed to determine the leads and lags in a CWC analysis for the Company?

A. Information from the Accounts Payable, Customer Service, Human Resources, Payroll, Treasury Management, and Tax systems are utilized. The information derived from these sources, together with analyses of specific invoices, is used to determine the appropriate number of lead/lag days for the Company's electric business.

Q. How should the results of the CWC analysis be treated for ratemaking purposes?

A. The CWC requirement should be included as part of Ameren Missouri's rate base for ratemaking purposes, and I have included it in my calculation of the revenue requirement as previously discussed.

Q. Was one revenue lag applied to all of the Company's revenues?

A. No. The Company calculated a base revenue lag that was then weighted for relevant components applicable to retail and interchange sales revenues. This weighted revenue lag was applied to all cash operating revenues with the exception of pass-through taxes. A separate revenue lag was calculated and applied to all revenues associated with pass-through taxes.

Q. How was the base revenue lag determined?

A. The base revenue lag measures the average number of days from the date service was rendered by the Company until the date payment was received from customers and such funds were deposited by the Company. In the calculation, the revenue lag was divided into three distinct components: 1) service lag; 2) billing lag; and 3) collections lag. Considered together, these three components of the base revenue lag totaled 39.48 lag days. An explanation of each component of the base revenue lag follows. Additionally, I will discuss how a total weighted revenue lag, incorporating interchange sales revenues, was calculated.

Q. What is meant by service lag?

A. The service lag refers to the number of days from the mid-point of the service period to the meter reading date for that service period. Using the mid-point methodology, the average lag associated with the provisioning of service was 15.21 days (365 days in the year divided by 12 months divided by 2).

Q. What is meant by billing lag?

A. Billing lag refers to the average number of days from the date on which the meter was read until the customer was billed. The billing lag was determined by analyzing the Company's monthly billing schedules and meter reading records. The average billing lag was determined to be 0.99 days.

Q. What is meant by collections lag?

A. The collections lag refers to the average amount of time from the date when the customer received a bill to the date that the Company received payment from its customers. Based on weighted average data from the Company's Customer Service System, the average collection lag was determined to be 23.28 days.

Q. What data was used to calculate the collections lag?

A. The Company used data from the bill payment report which was created to support the calculation of the collections lag.

Q. Please describe the bill payment report used in the collections lag calculation.

A. The Company developed a bill payment report to aggregate actual customer payments. This allows us to better understand customer payment behavior. The bill payment report compares the date a customer is billed to the date the bill was paid to arrive at the lag days. The bill payment report summarizes the dollar amounts collected per lag day. The lag days for each line item are capped at 150 days. Each line item is then weighted to calculate the weighted lag days. The bill payment report was run monthly for the period from January 2020 to December 2020.

Q. How were uncollectible revenues treated in your analysis?

A. The bill payment report aggregates actual customer payments. Therefore, an adjustment for uncollectible revenues is not needed in the analysis.

Q. Please summarize the calculation of base revenue lag days.

A. The calculation of the overall base revenue lag, by lag component, is summarized in the following table. Please note that the revenue lag pertains to revenue lag for items other than off-system sales, which I will address below.

Base Revenue Lag Component	Lag Days
Service	15.21
Billing	0.99
Collections	23.28
Total Revenue Lag	39.48

Q. You mentioned that the above figures do not include the revenue lag for off-system sales. What is the overall revenue lag once off-system sales are included?

A. Revenues from off-system sales were collected, on average, within 18.10 days. The proposed total retail revenues and off-system sales revenues were used to arrive at a weighted-average revenue lag for tariffed revenues and off-system sales. The resulting weighted revenue lag to be used in this filing was determined to be 37.02 days.

Q. How does the revenue lag applied to pass-through taxes differ from the base revenue lag?

A. The only difference between the base revenue lag and the revenue lag, which is applied to pass-through taxes is that the revenue lag applied to pass-through taxes excludes the service lag. Therefore, the revenue lag applied to pass-through taxes is 24.27 days.

Q. Why should a different revenue lag be applied to the pass-through tax revenues?

A. In prior cases, the Commission Staff has argued that pass-through taxes are not generated as a result of the provisioning of a service by the utility.[15] Therefore, in these proceedings a revenue lag which excludes a lag associated with the provisioning of utility service has been applied to the pass-through tax revenues.

Q. Are the revenues attributable to pass-through taxes collected in the same manner and at the same time as all other revenues?

A. Yes. The Company's customers pay one bill. That bill (and thus the payment) includes both operating revenues associated with the provisioning of electric service as well as revenues associated with pass-through taxes.

Q. What impact does the exclusion of the service lag from the revenue lag associated with pass-through taxes have on the CWC calculation?

A. The service lag represents the period of time during which the Company has provided a service for which it has not yet been compensated. Since the Company serves primarily as a collect and remit agent for the various taxing bodies, by excluding the service lag from the revenue lag applied to the pass-through taxes, the Company is reflecting that it has no out-of-pocket expense for which it is awaiting payment.

Q. What expense-related leads were considered in the lead/lag analysis?

A. Lead times associated with the following expense categories were considered in the lead/lag study: a) employee pensions and benefits; b) base payroll; c)

[15] Such proceedings include File Nos. ER-2010-0036 (AmerenUE), ER-2008-0318 (AmerenUE), ER-2007-0291 (Kansas City Power & Light Company), ER-2008-0093 (The Empire District Electric Company), GR-2007-0208 (Laclede Electric Company), and GR-2006-0422 (Missouri Gas Energy).

payroll taxes (i.e., FICA, Medicare) and other withholdings; d) cost of fuel – nuclear, coal, oil, and gas; e) purchased power; f) other operations and maintenance expenses; g) general taxes other than income taxes excluding pass-through taxes; h) pass-through taxes; i) federal income taxes; j) state income taxes; k) interest on long-term debt; l) decommissioning fees; and m) incentive compensation.

Q. What types of leads associated with the Company's employee benefit programs were considered in the analysis?

A. The estimated lead times associated with the following major categories of the Company's employee benefit programs were considered: a) group life insurance; b) group health insurance including claims processing, claims payment, and administration costs; c) the Company's 401-K plan; d) contributions to the Company's pension fund; and e) OPEB costs. Taken together, the group life insurance, group health insurance and 401-K plan had a dollar-weighted lead time of 17.65 days. Taken together, the pension and OPEB plans had a dollar-weighted lead time of 15.7 days.

Q. Provide an explanation of the leads associated with the Company's payroll expenses.

A. Payroll lead days were determined by calculating the nominal and weighted lead time by pay period and weighting the resulting lead days by the amounts paid by the Company to cover its payroll obligations. The resulting total on a dollar-weighted basis was 10.9 days.

Q. Please explain the lead effects associated with payroll taxes.

A. The Company has outsourced its payroll tax processing to a third-party provider, Ceridian. The payroll taxes outsourced to Ceridian include: a) Federal and State

Withholding Taxes; b) Federal and State Unemployment Taxes; c) FICA (Social Security) Taxes and Medicare Taxes for both employee and employer; and d) City of St. Louis Employee Withholding Tax and St. Louis City Employer Expense. Ceridian pulls all payroll taxes out of the Company's bank account on the same date as the employees are paid. Therefore, the payroll taxes lead time is equal to the base payroll lead time of 9.38 days.

Q. What are the lead times associated with other operations and maintenance expenses?

A. The Company engages in transactions with other vendors (not associated with pensions, benefits, payroll, fuel, or taxes) for a variety of purposes including facility maintenance, system maintenance, and customer service. Invoices from providers of such services were analyzed in order to estimate a lead time associated with payment for services related to other operations and maintenance activities. The analysis indicates that on average, invoices were paid by the Company 42.25 days after receipt.

Q. What is the expense lead time associated with the Company's contribution to the nuclear decommissioning trust fund?

A. The Company made quarterly contributions to the nuclear decommissioning trust fund during the twelve months ended December 31, 2020. Based on an examination of the contributions to the trust, a weighted average lead time of 69.5 days was determined.

Q. What is the lead time applicable to expenses associated with the Company's nuclear fuel?

A. The Company purchases and owns all of its current nuclear fuel. At the time the nuclear fuel is purchased, it is included in construction work in progress ("CWIP") and accrues an Allowance for Funds Used During Contraction ("AFUDC"). The nuclear fuel accrues AFUDC until it arrives at the reactor site. At that time, the nuclear fuel is in stock and the AFUDC ceases. When the nuclear fuel assemblies are loaded into the reactor, they are moved from stock to in service. The nuclear fuel is then amortized to expense each month as it is burned. The average unburned nuclear fuel is included in the materials and supplies inventory in rate base. Therefore, the only lag is between the monthly burn charged to expense and when this expense is recovered in revenue. Thus, a service lag of 15.21 days is used for the expense lead.

Q. How did you determine the expense lead time associated with the Company's purchase of coal and related services?

A. Invoices related to purchases of coal were examined to determine the expense lead time associated with the Company's coal purchases. When weighted by the dollar amounts shown in the invoices examined, a weighted average expense lead time of 14.43 days was determined.

Q. What is the expense lead time associated with the Company's purchase of oil to support its electric operations?

A. Based on an examination of invoices from the suppliers of oil to the Company, a weighted average lead time of 14.69 days was determined.

Q. What is the expense lead time associated with the Company's purchase of natural gas to support its electric operations?

A. Based on an examination of invoices from commodity and pipeline suppliers to the Company, a weighted average lead time of 40.72 days was determined.

Q. What type of leads were associated with the Company's purchase of electricity?

A. The Company purchases electricity from MISO as well as other sources. Based on an examination of the service periods and payment dates for the Company's sources of purchased power, a weighted lead time of 18.10 days was determined.

Q. What are the various general taxes considered in the analysis?

A. The following general taxes were considered in the study: a) Real Estate and Property Taxes; b) Missouri Sales Tax; c) Missouri and Iowa Use Tax; d) Illinois Use Tax; e) St. Louis Corporate Earnings Taxes; f) Federal Excise Heavy Use Tax; g) Self Procured Insurance Tax; h) Ohio Commercial Activity Tax; i) Corporate Franchise Tax; and j) Gross Receipts Taxes. When taxes were required to be paid to a single taxing authority pursuant to a set schedule, the statutory payment dates were considered in the analysis.

Q. Explain the leads that were calculated for each type of general taxes considered in the analysis.

A. The treatment of each category of general taxes in the study is described below:

1) Real Estate and Property Taxes: All current-year property taxes in Missouri are due on December 31st of the current year. Taking this schedule into consideration, a dollar-weighted expense lead of 183.0 days was calculated.

2) Missouri Sales Tax: Missouri sales tax is payable to the Missouri Department of Revenue and was calculated as a percent of billings less a 2 percent timely payment allowance. Estimated payments were made weekly with the tax return and the

remaining balance due. Taking this information into account, a weighted expense lead time of 4.5 days was determined.[16]

3) Missouri and Iowa Use Tax: Missouri and Iowa use tax is payable to the Missouri Department of Revenue and Iowa Department of Revenue, respectively, on the last day of the month following the end of the quarter. Taking this information into account, the expense lead time associated with the Missouri and Iowa use taxes was determined to be 76.25 days.

4) Illinois Use Tax: Illinois use tax is payable to the Illinois Department of Revenue on the 20th of the month following the end of the month. Taking this information into account, the expense lead time associated with the Illinois use taxes was determined to be 35.78 days.

5) St. Louis Corporate Earnings Tax: The Company pays corporate earnings taxes to the City of St. Louis. This tax is paid by check to the City of St. Louis annually on April 1st for the previous year. Taking this information into account, the expense lead time associated with corporate earnings taxes was determined to be 274.50 days.

6) Federal Heavy Use Tax: The federal heavy use tax is paid annually to the federal government at the beginning of the tax period. Additional payments are made as heavy vehicles are added. Taking this information into account, the expense lead time associated with the federal heavy use tax was determined to be (125.57) days.

7) Self Procured Insurance Tax: The self-procured insurance tax is paid to the State of Missouri each year. Taking this information into account, the expense lead time associated with self-procured insurance taxes was determined to be 241.50 days.

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[16] The Company has elected to align its study with Staff's position in File No. ER-2022-0337; accordingly the Company has removed the service lead and lag components of sales tax CWC factors.

8) Ohio Commercial Activity Tax: The Ohio commercial activity tax is a quarterly tax paid to the Ohio Department of Revenue. This tax is paid when the Company sells excess power to Ohio purchasers. Taking this information into account, the expense lead time associated with the Ohio commercial activity taxes was determined to be (50.00) days.

9) Corporate Franchise Tax – The Company had one payment to the State of Illinois and one payment to the State of Oklahoma for Corporate Franchise Tax in the period. Taking this information into account, the expense lead time associated with corporate franchise taxes was determined to be 233.19 days.

Q. What pass-through taxes are included in the CWC analysis?

A. The only pass-through tax considered in the CWC analysis was Gross Receipts Tax.

Q. Please describe the timing of the payment of the Gross Receipt Taxes.

A. Gross receipts taxes are payable to municipalities and counties and are paid as a percent of billings to customers within the taxing authority. These taxes are paid on the last day of the month following the end of a month with the exception of Arnold, Brentwood, Cape Girardeau, Chesterfield, Clayton, Dexter, Fenton, Florissant, Jefferson City, Jennings, Kirksville, Ladue, Maryland Heights, Moberly, St. Louis County, and Wentzville that are paid on the 20th day of the month. Based on the specific tax periods of the various taxing authorities, a dollar-weighted gross receipts tax expense lead time of 26.99 days was calculated.

Q. Does the lead time for gross receipts taxes include a service lead?

A. No. Since no service lag was included in the revenue lag assigned to pass-through taxes, there has been no service lead attributed to the gross receipts taxes.

Q. Please explain.

A. Both the service lag and the service lead are associated with the timing of the provisioning of service. If there is no service lag on the revenue side, there can be no service lead on the expense side. Therefore, for consistency purposes, I have excluded both the service lag and service lead from the analysis of the pass-through taxes.

Q. How did your study address federal income taxes?

A. The lead time associated with federal income tax payments was based on the provisions of the Internal Revenue Code that require estimated tax payments of 25 percent of total income taxes due on April 15, June 15, September 15, and December 15 of the current year. Taking this schedule into consideration a lead time of 38.00 days for federal income tax payments made by the Company was determined.

Q. How did the study address Missouri state income taxes?

A. Missouri state income taxes follow a pattern similar to federal taxes. Thus, assuming quarterly payments due on April 15, June 15, September 15, and December 15 of the current year, an expense lead time of 38.00 days was determined.

Q. Were income taxes paid to any state other than Missouri during the study period?

A. Yes, one payment was made to the State of Indiana and one payment was made to the State of Iowa.

Q. How did your study address state income taxes for states other than Missouri?

A. The weighed expense lead time for each state was calculated separately. An expense lead time of 14.00 days was determined for Indiana State Income Taxes and an expense lead time of (77.00) days was determined for Iowa State Income Taxes.

Q. Provide a description of how lead times associated with the Company's interest expenses were addressed by the study.

A. The Company's interest payments on its long-term bonds were made from current revenues. Thus, there was a lead (or lag) between the date the interest payments were collected from customers and the date when such amounts were paid to financial institutions. The Company generally made interest payments on its fixed rate long-term debt twice a year at varying times. Using actual due dates on interest payments, a dollar-weighted lead of 91.37 days for interest payments was determined.

Q. How did the study address contributions to the incentive compensation plans?

A. The Company made an annual contribution to incentive compensation programs for both the executive incentive plan and the management/bargaining unit plans during the test year. The executive incentive plan contribution is made on the last date in February, while the management/bargaining unit contributions are made during the first pay period in March. Based on an examination of the contributions to the incentive compensation plans, a weighted average lead time of 250.80 days was determined.

Q. Please describe Schedule SJH-D18.

A. Schedule SJH-D18 summarizes the leads and lags discussed in my direct testimony that I used to develop the CWC factors. These CWC factors are used to calculate the Company's cash working capital requirements.

VI. CONCLUSION

Q. Please summarize your testimony and conclusions.

A. My testimony and attached schedules have developed the Company's total electric rate base and revenue requirement, which include the continuation of seven trackers: uncertain tax positions tracker (a/k/a Fin. 48 tracker)[17], pension tracker, OPEB tracker, RES tracker, excess deferred tax tracker, Inflation Reduction Act ("IRA") tracker[18], and the statutory property tax tracker. My testimony also includes the amortization of existing regulatory assets and liabilities. As summarized in Schedule SJH-D16, the Company's total electric revenue requirement, including the Company's proposed 7.398% return on rate base, is more than the pro forma operating revenues at the present rates by $446,198,000. Consequently, rates should be designed to increase revenues by $446,198,000, subject to the true-up in this case. Finally, the seasonal values of Factor BF in Rider FAC should be set at the values shown in Schedule SJH-D17, reflecting a re-base of net base energy costs.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[17] The base level for the uncertain tax positions tracker is set at $0.
[18] The base level for the IRA tracker is set at $0.

AMEREN MISSOURI
ORIGINAL COST OF ELECTRIC PLANT
BY FUNCTIONAL CLASSIFICATION FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	FUNCTIONAL CLASSIFICATION (A)	TOTALS PER BOOKS (B)	PRO FORMA ADJUSTMENTS (C)	PRO FORMA ELECTRIC TOTALS (D)
	INTANGIBLE PLANT			
1	FRANCHISES	$ 123,092	$ -	$ 123,092
2	CALLAWAY LIFE EXTENSION DEFERRAL	2,812	-	2,812
3	MISC INTANGIBLE PLANT	879,788	47,247	927,035
4	**TOTAL INTANGIBLE PLANT**	1,005,692	47,247	1,052,939
	PRODUCTION PLANT			
5	NUCLEAR	3,617,369	9,656	3,627,025
6	CALLAWAY POST OPERATIONAL	116,731	-	116,731
7	STEAM	4,446,772	(787,721)	3,659,051
8	HYDRAULIC	646,103	13,463	659,566
9	WIND	1,221,048	(41,843)	1,179,205
10	OTHER	1,279,111	995,925	2,275,036
11	**TOTAL PRODUCTION PLANT**	11,327,134	189,480	11,516,614
12	**TRANSMISSION PLANT**	2,138,313	249,527	2,387,840
13	**DISTRIBUTION PLANT**	8,736,106	734,250	9,470,356
14	**GENERAL PLANT**	1,205,682	130,286	1,335,968
15	**INCENTIVE COMPENSATION CAPITALIZED**	-	(59,862)	(59,862)
16	**TOTAL PLANT IN SERVICE**	**$ 24,412,927**	**$ 1,290,928**	**$ 25,703,855**

PRO FORMA ADJUSTMENTS

LINE	DESCRIPTION		AMOUNT	TOTAL
17	(1)	Eliminate plant in service related to ASC 410-20 Asset Retirement Obligations and ASC 842 Leases.		
18		NUCLEAR	$ (92,750)	
19		STEAM	(106,512)	
20		WIND	(52,681)	
21		DISTRIBUTION	-	
22		OTHER	(1,262)	
23		GENERAL	(3,682)	
24		TOTAL		$ (256,887)
25	(2)	Plant additions for the true-up period.		
26		MISC INTANGIBLE PLANT	86,560	
27		NUCLEAR	102,406	
28		STEAM	195,878	
29		HYDRAULIC	13,463	
30		WIND	10,838	
31		OTHER	997,187	
32		TRANSMISSION	249,527	
33		DISTRIBUTION	734,250	
34		GENERAL	163,314	
35		TOTAL		2,553,423
36	(3)	Reduce Rush Island Energy Center plant in service based on Lansford's Supplemental Testimony in EF-		
37		2024-0021 with the October 15, 2024 retirement date (net of projected transfers to other energy		
38		centers).		
39		STEAM	(877,088)	
40		GENERAL	(336)	
41		TOTAL		(877,424)
42	(4)	Eliminate portions of plant in service for multi use general assets which are applicable to gas		
43		operations. For convenience, such assets are recorded as electric plant but are commonly used for both		
44		electric and gas.		
45		MISC INTANGIBLE PLANT	(39,297)	
46		GENERAL	(29,010)	
47		TOTAL		(68,307)
48	(5)	Reduce plant in service for specified incentive compensation capitalized.		
49		GENERAL		(59,877)
50		**TOTAL PRO FORMA ADJUSTMENTS**		**$ 1,290,928**

AMEREN MISSOURI
TOTAL ELECTRIC RESERVES FOR DEPRECIATION AND AMORTIZATION
BY FUNCTIONAL CLASSIFICATION FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	FUNCTIONAL CLASSIFICATION (A)	TOTALS PER BOOKS (B)	PRO FORMA ADJUSTMENTS (C)	PRO FORMA ELECTRIC TOTALS (D)
	INTANGIBLE PLANT			
1	FRANCHISES	$ 40,474	$ 3,027	$ 43,501
2	CALLAWAY LIFE EXTENSION DEFERRAL	677	78	755
3	MISC INTANGIBLE PLANT	503,640	(15,812)	487,828
4	**TOTAL INTANGIBLE PLANT**	544,791	(12,707)	532,084
	PRODUCTION PLANT			
5	NUCLEAR	1,917,557	60,496	1,978,053
6	CALLAWAY POST OPERATIONAL	114,580	2,151	116,731
7	STEAM	2,041,550	(343,446)	1,698,104
8	HYDRAULIC	163,025	12,442	175,467
9	WIND	137,841	26,104	163,945
10	OTHER	724,015	19,109	743,124
11	**TOTAL PRODUCTION PLANT**	5,098,568	(223,144)	4,875,424
12	**TRANSMISSION PLANT**	555,109	40,841	595,950
13	**DISTRIBUTION PLANT**	3,408,520	184,241	3,592,761
14	**GENERAL PLANT**	325,980	43,669	369,649
15	**INCENTIVE COMPENSATION CAPITALIZED**	-	(19,659)	(19,659)
16	**TOTAL DEPRC. & AMORT RESERVE**	**$ 9,932,968**	**$ 13,241**	**$ 9,946,209**
	PRO FORMA ADJUSTMENTS			
17	(1) Eliminate reserve related to ASC 410-20 Asset Retirement Obligations and ASC 842 Leases.			
18	NUCLEAR		$ (2,531)	
19	STEAM		(79,241)	
20	WIND		(5,644)	
21	OTHER		(76)	
22	GENERAL		(1,948)	
23	TOTAL			$ (89,440)
24	(2) Reserve at March 31, 2024 adjusted to reflect reserve at December 31, 2024.			
25	FRANCHISES		3,027	
26	CALLAWAY LIFE EXTENSION DEFERRAL		78	
27	NUCLEAR		62,063	
28	CALLAWAY POST OPERATIONAL		2,151	
29	STEAM		157,045	
30	HYDRAULIC		12,305	
31	WIND		31,600	
32	OTHER		17,444	
33	TRANSMISSION		39,148	
34	DISTRIBUTION		178,137	
35	GENERAL		50,721	
36	TOTAL			553,719
37	(3) Adjustment to reserve for the additions to plant in service for the true-up period of			
38	April 1, 2024 through December 31, 2024.			
39	MISC INTANGIBLE PLANT		5,364	
40	NUCLEAR		964	
41	STEAM		3,665	
42	HYDRAULIC		136	
43	WIND		149	
44	OTHER		1,741	
45	TRANSMISSION		1,693	
46	DISTRIBUTION		6,104	
47	GENERAL		2,953	
48	TOTAL			22,769
49	(4) Rush Island Energy Center adjustment. See Schedule SJH-D1 adjustment (3).			
51	STEAM		(424,914)	
52	GENERAL		(329)	
				(425,243)
53	(5) Eliminate portions of reserve for multi use general assets which are applicable to			
54	gas operations. For convenience, such assets are recorded as electric plant but			
55	are commonly used for both electric and gas operations.			
56	MISC INTANGIBLE PLANT		(21,163)	
57	GENERAL		(7,728)	
58	TOTAL			(28,891)
59	(6) Reduce reserve for specified incentive compensation capitalized.			
60	GENERAL			(19,673)
61	**TOTAL PRO FORMA ADJUSTMENTS**			**$ 13,241**

AMEREN MISSOURI
AVERAGE FUEL AND MATERIALS & SUPPLIES INVENTORIES
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	DESCRIPTION (A)	TOTALS PER BOOKS (B)	PRO FORMA ADJUSTMENTS (C)	PRO FORMA ELECTRIC TOTALS (D)
1	**AVERAGE NUCLEAR FUEL**	$ 141,300	$ -	$ 141,300
	AVERAGE FOSSIL FUEL:			
2	COAL	94,223	(15,400)	78,823
3	OIL	7,068	-	7,068
4	STORED GAS FOR CTG'S	2,041	-	2,041
5	**TOTAL FOSSIL FUEL**	103,332	(15,400)	87,932
6	**EMISSION ALLOWANCES AND RECS**	111	-	111
7	**GENERAL MATERIALS AND SUPPLIES**	397,262	(20,648)	376,614
8	**TOTAL**	**$ 642,005**	**$ (36,048)**	**$ 605,957**

LINE		PRO FORMA ADJUSTMENT	
9	(1)	Adjust coal supply to remove Rush Island Energy Center coal inventories and to reflect 13-month average	$ (15,400)
10		inventory levels priced at the January 2025 coal prices.	
11	(2)	Reduce Rush Island Energy Center general materials and supplies inventories to reflect the Company's	(18,304)
12		position in EF-2024-0021, assuming an October 15, 2024 retirement date.	
13	(3)	Eliminate portions of average fuel and general materials and supplies which are applicable to gas operations.	(2,344)
14		**TOTAL PRO FORMA ADJUSTMENTS**	$ (36,048)

AMEREN MISSOURI
AVERAGE PREPAYMENTS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	DESCRIPTION	TOTALS PER BOOKS (1)	PRO FORMA ADJUSTMENTS	PRO FORMA ELECTRIC TOTALS
	(A)	(B)	(C)	(D)
1	RENTS (2)	$ 9	$ -	$ 9
2	INSURANCE (2)	11,552	(759)	10,793
3	SOFTWARE MAINTENANCE PREPAYMENTS (3)	12,188	(341)	11,847
4	MEMBERSHIP DUES (3)	300	(8)	292
5	GAS MBP INSURANCE (2)	10	(10)	-
6	ELECTRIC MBP INSURANCE (2)	77	-	77
7	POWER/CAPACITY PREPAID (2)	109	-	109
8	MEDICAL AND DENTAL VEBA (3)	4,844	(136)	4,708
9	GAS MEMBERSHIP DUES (2)	27	(27)	-
10	LOW INCOME WEATHERIZATION (2)	28	(28)	-
11	**TOTAL AVERAGE PREPAYMENTS**	**$ 29,144**	**$ (1,309)**	**$ 27,835**

12 (1) Reflects 13-month average.
13 (2) Directly assigned to electric or gas.
14 (3) Allocated to gas based on operating expenses excluding fuel and purchased power.

PRO FORMA ADJUSTMENT

15	(1) Eliminate portions of prepayments which are applicable to gas operations. Amounts	$ (1,309)
16	were either directly assigned to gas operations or were allocated between electric and	
17	gas operations based on operating expenses excluding fuel and purchased power.	

AMEREN MISSOURI
TOTAL ELECTRIC CASH WORKING CAPITAL
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	DESCRIPTION (A)	REVENUE LAG (B)	EXPENSE LEAD (1) (C)	NET LEAD/LAG (D)	FACTOR (E)	TEST YEAR EXPENSE (F)	CASH WORKING CAPITAL REQUIREMENT (G)
1	PAYROLL & WITHHOLDINGS	37.020	(10.900)	26.120	0.071562	$ 356,421	$ 25,506
2	PENSIONS AND BENEFITS	37.020	(15.700)	21.320	0.058411	(95,227)	(5,562)
3	OTHER EMPLOYEE BENEFITS	37.020	(17.650)	19.370	0.053068	50,730	2,692
4	FUEL						
5	NUCLEAR	37.020	(15.210)	21.810	0.059753	69,003	4,123
6	COAL	37.020	(14.430)	22.590	0.061890	374,280	23,164
7	NATURAL GAS	37.020	(40.720)	(3.700)	(0.010137)	28,837	(292)
8	OIL	37.020	(14.690)	22.330	0.061178	2,593	159
9	PURCHASED POWER	37.020	(18.100)	18.920	0.051836	474,458	24,594
10	INCENTIVE COMPENSATION	37.020	(250.800)	(213.780)	(0.585699)	34,310	(20,095)
11	UNCOLLECTIBLE ACCOUNTS	37.020	(37.020)	0.000	-	11,302	-
12	OTHER OPERATING EXPENSES	37.020	(42.250)	(5.230)	(0.014329)	542,231	(7,770)
13	TOTAL O&M EXPENSES					1,848,938	
14	**TOTAL CASH WORKING CAPITAL REQUIREMENT**						**46,519**
15	FICA - EMPLOYER'S PORTION	37.020	(9.380)	27.640	0.075726	19,744	1,495
16	ST. LOUIS PAYROLL EXPENSE TAXES	37.020	(9.380)	27.640	0.075726	345	26
17	FEDERAL UNEMPLOYMENT TAXES	37.020	(9.380)	27.640	0.075726	180	14
18	STATE UNEMPLOYMENT TAXES	37.020	(9.380)	27.640	0.075726	33	2
19	CORPORATE FRANCHISE TAXES	37.020	(233.190)	(196.170)	(0.537452)	107	(58)
20	PROPERTY TAXES	37.020	(183.000)	(145.980)	(0.399945)	180,432	(72,163)
21	DECOMMISSIONING FEES	37.020	(69.500)	(32.480)	(0.088986)	6,759	(601)
22	SALES TAXES	24.270	(4.500)	19.770	0.054164	80,232	4,346
23	MO & IA USE TAXES	37.020	(76.250)	(39.230)	(0.107479)	4,574	(492)
24	IL USE TAXES	37.020	(35.780)	1.240	0.003397	61	-
25	FED EXCISE HEAVY USE TAX	37.020	125.570	162.590	0.445452	52	23
26	SELF PROCURED INS TAX	37.020	(241.500)	(204.480)	(0.560219)	274	(154)
27	OHIO COMMERCIAL ACTIVITY TAX	37.020	50.000	87.020	0.238411	-	-
28	GROSS RECEIPTS TAXES	24.270	(26.990)	(2.720)	(0.007452)	159,622	(1,190)
29	TOTAL TAXES AND OTHER EXPENSES					452,415	
30	**NET CUSTOMER SUPPLIED FUNDS**						**$ (68,752)**
31	**NET CASH WORKING CAPITAL REQUIREMENT**						**$ (22,233)**

AMEREN MISSOURI
TOTAL ELECTRIC FEDERAL AND STATE INCOME TAX AND CITY EARNINGS TAX CASH REQUIREMENTS
AND INTEREST EXPENSE CASH REQUIREMENT
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	DESCRIPTION (A)	REVENUE LAG (B)	EXPENSE LEAD (1) (C)	NET LEAD/LAG (D)	FACTOR (E)	TEST YEAR EXPENSE (F)	CASH WORKING CAPITAL REQUIREMENT (G)
1	FEDERAL INCOME TAX CASH REQUIREMENT	37.020	(38.000)	(0.980)	(0.002685)	$ 75,417	$ (202)
2	MO STATE INCOME TAX CASH REQUIREMENT	37.020	(38.000)	(0.980)	(0.002685)	$ 29,413	$ (79)
3	CITY EARNINGS TAX CASH REQUIREMENT	37.020	(274.500)	(237.480)	(0.650630)	$ 105	$ (68)
4	INTEREST EXPENSE CASH REQUIREMENT	37.020	(91.370)	(54.350)	(0.148904)	$ 286,778	$ (42,702)

AMEREN MISSOURI
TOTAL ELECTRIC AVERAGE CUSTOMER ADVANCES FOR CONSTRUCTION AND AVERAGE CUSTOMER DEPOSITS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	DESCRIPTION (A)	TOTAL ELECTRIC (B)
1	AVERAGE CUSTOMER ADVANCES FOR CONSTRUCTION	$ (1,537)
2	AVERAGE CUSTOMER DEPOSITS	$ (29,356)

AMEREN MISSOURI
OTHER REGULATORY ASSETS
AND REGULATORY LIABILITIES
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	DESCRIPTION (A)	TOTAL ELECTRIC (B)(1)
1	**PENSION TRACKER**	$ (60,210)
2	**OTHER POST-EMPLOYMENT BENEFITS (OPEB) TRACKER**	$ (17,453)
3	**PAYS REGULATORY ASSET**	$ 1,710
4	**PISA REGULATORY ASSET**	$ 611,655
5	**MERAMEC RETIREMENT REGULATORY ASSET**	$ 33,512
6	**EXPIRED & EXPIRING AMORTIZATIONS IN RATE BASE**	$ (1,830)
7	**PROPERTY TAX TRACKER**	$ 23,509

8 (1) A positive balance is a Regulatory Asset and a negative balance is a
9 Regulatory Liability.

AMEREN MISSOURI
ACCUMULATED DEFERRED INCOME TAXES
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	DESCRIPTION (A)	TOTAL ELECTRIC PER BOOKS (B)	PRO FORMA ADJUSTMENTS (C)	PRO FORMA ELECTRIC TOTAL (D)
1	**ACCOUNT 190**	$ 61,817	$ 1,891	$ 63,708
2	**ACCOUNT 281**	(75,333)	-	(75,333)
3	**ACCOUNT 282**	(2,840,648)	130,874	(2,709,774)
4	**ACCOUNT 283**	(140,378)	(1,022)	(141,400)
5	**TOTAL ACCUMULATED DEFERRED INCOME TAXES**	**$ (2,994,542)**	**$ 131,743**	**$ (2,862,799)**

PRO FORMA ADJUSTMENT:

6 Changes in balances from March 31, 2024 to December 31, 2024, which is the end of the true-up period.

AMEREN MISSOURI
TOTAL ELECTRIC PER BOOK AND PRO FORMA OPERATING REVENUES
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE		DESCRIPTION (A)	TOTAL ELECTRIC (B)	PRO FORMA ADJUSTMENTS (C)	ADJUSTED TOTAL ELECTRIC (D)
		OPERATING REVENUES			
1		RETAIL REVENUES	$ 3,204,812	$ (318,077)	2,886,734
2		PROVISION FOR RATE REFUNDS	4,323	(4,323)	-
3		OTHER ELECTRIC REVENUES	86,123	3,092	89,215
4		**TOTAL REVENUES**	**3,295,258**	**(319,308)**	**2,975,949**
5		DISPOSITION OF ALLOWANCES	-	-	-
6		OFF-SYSTEM SALES - ENERGY	90,393	170,377	260,770
7		OFF-SYSTEM SALES - CAPACITY	128,387	258,385	386,772
8		**TOTAL REVENUES PER BOOKS**	**$ 3,514,038**	**$ 109,454**	**$ 3,623,491**
		PRO FORMA ADJUSTMENTS:			
9	(1)	REMOVE ADD ON REVENUE TAX	(159,576)		
10	(2)	ELIMINATE REVENUE FROM MEEIA RECOVERIES	(89,504)		
11	(3)	ELIMINATE REVENUE FROM FAC RECOVERIES	(134,839)		
12	(4)	ELIMINATE UNBILLED REVENUE	345		
13	(5)	ANNUALIZE RATE CHANGE	39,468		
14	(6)	ADJUST FOR PRO FORMA EDI	(8,226)		
15	(7)	ADJUST TO REMOVE TEST YEAR EDI	5,871		
16	(8)	ADJUST FOR COMMUNITY SOLAR	1,623		
17	(9)	ADJUST FOR GROWTH	20,281		
18	(10)	ADJUST FOR RESRAM REVENUES	(15,366)		
19	(11)	ADJUST FOR ENERGY EFFICIENCY AND SOLAR ANNUALIZATION	(9,416)		
20	(12)	DAYS ADJUSTMENT	148		
21	(13)	ADJUST FOR BILLING UNITS	3,536		
22	(14)	ADJUST FOR NORMAL WEATHER	20,541		
23	(15)	ADJUST FOR RSP REVENUES	7,037		
24		TOTAL RETAIL REVENUES		(318,077)	
25	(16)	ELIMINATE PROVISION FOR RATE REFUNDS		(4,323)	
26	(17)	ADJUST TRANSMISSION REVENUES	2,814		
27	(18)	ADJUST LEASE REVENUE FROM RENT	1,814		
28	(19)	MISC LEASE REVENUE FROM SOFTWARE LEASES	(794)		
29	(20)	ADJUST FOR PAYS REVENUES	16		
30	(21)	REMOVE ADD ON REVENUE TAX	(758)		
31		TOTAL OTHER ELECTRIC REVENUES		3,092	
32	(22)	ELIMINATE DISPOSITION OF ALLOWANCES		-	
33	(23)	ADJUST OFF-SYSTEM SALES - ENERGY		170,377	
34	(24)	ADJUST OFF-SYSTEM SALES - CAPACITY		258,385	
35		**TOTAL PRO FORMA ADJUSTMENTS**		$ 109,454	

AMEREN MISSOURI
ELECTRIC OPERATING AND MAINTENANCE EXPENSES
PER BOOK AND PRO FORMA
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024 UPDATED THROUGH DECEMBER 31, 2024
($000)

LINE	FUNCTIONAL CLASSIFICATION (A)	TOTAL PER BOOKS (B)	#1 LABOR ADJUSTMENT (C)	#2 INCENTIVE COMPENSATION ADJUSTMENT (D)	#3 LONG TERM INCENTIVE COMPENSATION ADJUSTMENT (E)	#4 CHANGE IN FUEL EXPENSE FOR TU CHANGE (F)	#5 ADJUST PURCHASED POWER FOR TU CHANGE (G)	#6 MARK TWAIN TRANSMISSION ADJUSTMENT (H)	#7 STEAM PLANT MAINTENANCE (I)	#8 RUSH IISLAND MAINTENANCE ADJUSTMENT (J)
	PRODUCTION:									
	INCREMENTAL COSTS:									
1	LABOR	$ 199,223	$ 10,564	$ (1,075)	$ (2,154)	$ -	$ -	$ -	$ -	$ -
	FUEL (EXCL. W/H CR.)									
2	BASE LOAD	401,676	-	-	-	9,647	-	-	-	-
3	INTERCHANGE	50,796	-	-	-	20,289	-	-	-	-
4	FUEL ADDITIVES	6,690	-	-	-	506	-	-	-	-
	PURCHASED POWER									
	ENERGY									
5	BASE LOAD	99,595	-	-	-	-	10,239	-	-	-
6	INTERCHANGE	14,663	-	-	-	-	(14,663)	-	-	-
	CAPACITY COSTS									
7	BASE LOAD	122,624	-	-	-	-	241,999	-	-	-
8	INTERCHANGE	-	-	-	-	-	-	-	-	-
9	OTHER	207,046	-	-	-	-	-	-	274	(2,552)
10	TOTAL PRODUCTION EXPENSES	1,102,313	10,564	(1,075)	(2,154)	30,442	237,575	-	274	(2,552)
	TRANSMISSION EXPENSES:									
11	LABOR	6,430	329	(35)	(94)	-	-	-	-	-
12	OTHER	102,746	-	-	-	-	9,495	(108)	-	-
13	TOTAL TRANSMISSION EXPENSES	109,176	329	(35)	(94)	-	9,495	(108)	-	-
	REGIONAL MARKET EXPENSES:									
14	LABOR	-	-	-	-	-	-	-	-	-
15	OTHER	6,403	-	-	-	-	-	-	-	-
16	TOTAL REGIONAL MARKET EXPENSES	6,403	-	-	-	-	-	-	-	-
	DISTRIBUTION EXPENSES:									
17	LABOR	69,788	3,711	(377)	(878)	-	-	-	-	-
18	OTHER	95,335	-	-	-	-	-	-	-	-
19	TOTAL DISTRIBUTION EXPENSES	165,123	3,711	(377)	(878)	-	-	-	-	-
	CUSTOMER ACCOUNTS EXPENSES:									
20	LABOR	19,291	1,053	(104)	(70)	-	-	-	-	-
21	OTHER	34,634	-	-	-	-	-	-	-	-
22	TOTAL CUSTOMER ACCOUNTS EXPENSES	53,925	1,053	(104)	(70)	-	-	-	-	-
	CUSTOMER SERV. & INFO. EXPENSES:									
23	LABOR	8,217	393	(44)	(192)	-	-	-	-	-
24	OTHER	85,803	-	-	-	-	-	-	-	-
25	TOTAL CUSTOMER SERV. & INFO. EXPENSES	94,020	393	(44)	(192)	-	-	-	-	-
	SALES EXPENSES:									
26	LABOR	401	19	(2)	-	-	-	-	-	-
27	OTHER	23	-	-	-	-	-	-	-	-
28	TOTAL SALES EXPENSES	424	19	(2)	-	-	-	-	-	-
	ADMINISTRATIVE & GENERAL EXPENSES:									
29	LABOR	72,497	3,287	(391)	(3,958)	-	-	-	-	-
30	OTHER	103,177	-	-	-	-	-	-	-	-
31	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**	175,674	3,287	(391)	(3,958)	-	-	-	-	-
32	**TOTAL OPERATIONS & MAINTENANCE EXPENSES**	**$ 1,707,058**	**$ 19,356**	**$ (2,028)**	**$ (7,346)**	**$ 30,442**	**$ 247,070**	**$ (108)**	**$ 274**	**$ (2,552)**

33 **NOTE:** See SCHEDULE SJH-D11-7 for explanation of the pro forma adjustments.

AMEREN MISSOURI
ELECTRIC OPERATING AND MAINTENANCE EXPENSES
PER BOOK AND PRO FORMA
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024 UPDATED THROUGH DECEMBER 31, 2024
($000)

LINE	REMOVE MEMBERSHIP DUES FUNCTIONAL CLASSIFICATION (A)	#9 MERAMEC MAINTENANCE ADJUSTMENT (B)	#10 ELIMINATE FAC RECOVERY (C)	#11 CALLAWAY REFUELING EXPENSES (D)	#12 REMOVE CALLAWAY REFUELING AMORTIZATION (E)	#13 OTHER RES ADJUSTMENT (F)	#14 REBASE RES EXPENSE (G)	#15 ELIMINATE SOLAR AMOUNTS (H)	#16 DEPRECIATION TO O&M ADJUSTMENT (I)	#17 NORMALIZE STORM COSTS (J)
	PRODUCTION:									
	INCREMENTAL COSTS:									
1	LABOR		$ -	$ 5,416	$ -	-	$ -	$ -	$ -	$ -
	FUEL (EXCL. W/H CR.)									
2	BASE LOAD		-	-	-	-	-	-	-	-
3	INTERCHANGE		-	-	-	-	-	-	-	-
4	FUEL ADDITIVES	-	-	-	-	-	-	-	-	-
	PURCHASED POWER									
	ENERGY									
5	BASE LOAD	-	-	-	-	-	-	-	-	-
6	INTERCHANGE	-	-	-	-	-	-	-	-	-
	CAPACITY COSTS						-	-	-	-
7	BASE LOAD	-	-	-	-	-	-	-	-	-
8	INTERCHANGE	-	-	-	-	-	-	-	-	-
9	OTHER	(3,444)	(50,958)	24,760	(34,133)	(648)	(1,676)	-	1,683	-
10	TOTAL PRODUCTION EXPENSES	(3,444)	(50,958)	30,176	(34,133)	(648)	(1,676)	-	1,683	-
	TRANSMISSION EXPENSES:									
11	LABOR	-	-	-	-	-	-	-	-	-
12	OTHER	-	-	-	-	-	-	-	-	-
13	TOTAL TRANSMISSION EXPENSES	-	-	-	-	-	-	-	-	-
	REGIONAL MARKET EXPENSES:									
14	LABOR	-	-	-	-	-	-	-	-	-
15	OTHER	-	-	-	-	-	-	-	-	-
16	TOTAL REGIONAL MARKET EXPENSES	-	-	-	-	-	-	-	-	-
	DISTRIBUTION EXPENSES:									
17	LABOR	-	-	-	-	-	-	-	-	-
18	OTHER	-	-	-	-	-	-	-	(345)	(3,103)
19	TOTAL DISTRIBUTION EXPENSES	-	-	-	-	-	-	-	(345)	(3,103)
	CUSTOMER ACCOUNTS EXPENSES:									
20	LABOR	-	-	-	-	-	-	-	-	-
21	OTHER	-	-	-	-	-	-	-	-	-
22	TOTAL CUSTOMER ACCOUNTS EXPENSES	-	-	-	-	-	-	-	-	-
	CUSTOMER SERV. & INFO. EXPENSES:									
23	LABOR	-	-	-	-	-	-	-	-	-
24	OTHER	-	-	-	-	-	-	(1,338)	-	-
25	TOTAL CUSTOMER SERV. & INFO. EXPENSES	-	-	-	-	-	-	(1,338)	-	-
	SALES EXPENSES:									
26	LABOR	-	-	-	-	-	-	-	-	-
27	OTHER	-	-	-	-	-	-	-	-	-
28	TOTAL SALES EXPENSES	-	-	-	-	-	-	-	-	-
	ADMINISTRATIVE & GENERAL EXPENSES:									
29	LABOR	-	-	-	-	-	-	-	-	-
30	OTHER	-	-	-	-	-	-	-	-	-
31	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**	-	-	-	-	-	-	-	-	-
32	**TOTAL OPERATIONS & MAINTENANCE EXPENSES**	**$ (3,444)**	**$ (50,958)**	**$ 30,176**	**$ (34,133)**	**$ (648)**	**$ (1,676)**	**$ (1,338)**	**$ 1,338**	**$ (3,103)**

33 **NOTE:** See SCHEDULE SJH-D11-7 for explanation of the pro forma adjustments.

SCHEDULE SJH-D11-2

AMEREN MISSOURI
ELECTRIC OPERATING AND MAINTENANCE EXPENSES
PER BOOK AND PRO FORMA
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024 UPDATED THROUGH DECEMBER 31, 2024
($000)

	FUNCTIONAL CLASSIFICATION (A)	#18 VEG MGMT & INFRA INSPEC COSTS (B)	#19 ADD INTEREST ON CUSTOMER DEPOSITS (C)	#20 ENERGY EFFICIENCY PROGRAM COST RECOVERY ADJUSTMENT (D)	#21 PAYS PROGRAM AMORTIZATION (E)	#22 ANNUALIZE BAD DEBT EXPENSE (F)	#23 STAFFING ANNUALIZATION ADJUSTMENT (G)	#24 INSURANCE ADJUST. (H)	#25 PRO FORMA MEDICAL & BENEFIT ADJUST. (I)
	PRODUCTION:								
	INCREMENTAL COSTS:								
1	LABOR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	FUEL (EXCL. W/H CR.)								
2	BASE LOAD	-	-	-	-	-	-	-	-
3	INTERCHANGE	-	-	-	-	-	-	-	-
4	FUEL ADDITIVES	-	-	-	-	-	-	-	-
	PURCHASED POWER								
	ENERGY								
5	BASE LOAD	-	-	-	-	-	-	-	-
6	INTERCHANGE	-	-	-	-	-	-	-	-
	CAPACITY COSTS	-	-						
7	BASE LOAD	-	-	-	-	-	-	-	-
8	INTERCHANGE	-	-	-	-	-	-	-	-
9	OTHER	-	-	-	-	-	-	-	-
10	TOTAL PRODUCTION EXPENSES	-	-	-	-	-	-	-	-
	TRANSMISSION EXPENSES:								
11	LABOR	-	-	-	-	-	-	-	-
12	OTHER	-	-	-	-	-	-	-	-
13	TOTAL TRANSMISSION EXPENSES	-	-	-	-	-	-	-	-
	REGIONAL MARKET EXPENSES:								
14	LABOR	-	-	-	-	-	-	-	-
15	OTHER	-	-	-	-	-	-	-	-
16	TOTAL REGIONAL MARKET EXPENSES	-	-	-	-	-	-	-	-
	DISTRIBUTION EXPENSES:								
17	LABOR	-	-	-	-	-	-	-	-
18	OTHER	(5,450)	-	-	-	-	-	-	-
19	TOTAL DISTRIBUTION EXPENSES	(5,450)	-	-	-	-	-	-	-
	CUSTOMER ACCOUNTS EXPENSES:								
20	LABOR	-	-	-	-	-	-	-	-
21	OTHER	-	2,789	-	-	2,075	-	-	-
22	TOTAL CUSTOMER ACCOUNTS EXPENSES	-	2,789	-	-	2,075	-	-	-
	CUSTOMER SERV. & INFO. EXPENSES:								
23	LABOR	-	-	-	-	-	-	-	-
24	OTHER	-	-	(71,459)	97	-	-	-	-
25	TOTAL CUSTOMER SERV. & INFO. EXPENSES	-	-	(71,459)	97	-	-	-	-
	SALES EXPENSES:								
26	LABOR	-	-	-	-	-	-	-	-
27	OTHER	-	-	-	-	-	-	-	-
28	TOTAL SALES EXPENSES	-	-	-	-	-	-	-	-
	ADMINISTRATIVE & GENERAL EXPENSES:								
29	LABOR	-	-	-	-	-	(515)	-	-
30	OTHER	-	-	-	-	-	(66)	3,263	327
31	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**	-	-	-	-	-	(581)	3,263	327
32	**TOTAL OPERATIONS & MAINTENANCE EXPENSES**	**$ (5,450)**	**$ 2,789**	**$ (71,459)**	**$ 97**	**$ 2,075**	**$ (581)**	**$ 3,263**	**$ 327**

33 **NOTE:** See SCHEDULE SJH-D11-7 for explanation of the pro forma adjustments.

AMEREN MISSOURI
ELECTRIC OPERATING AND MAINTENANCE EXPENSES
PER BOOK AND PRO FORMA
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024 UPDATED THROUGH DECEMBER 31, 2024
($000)

#26 NON-QUALIFIED PENSION ADJUST. (J)
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AMEREN MISSOURI
ELECTRIC OPERATING AND MAINTENANCE EXPENSES
PER BOOK AND PRO FORMA
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024 UPDATED THROUGH DECEMBER 31, 2024
($000)

LINE	FUNCTIONAL CLASSIFICATION (A)	#27 REBASE PENSION AND OPEB TRACKER (B)	#28 AMORTIZE PENSION AND OPEB TRACKER (C)	#29 RESRAM BASE EXPENSE (D)	#30 NET RATE CASE EXPENSES (E)	#31 MPSC ASSESSMENT (F)	#32 BOARD OF DIRECTORS EXPENSE ADJUSTMENT (G)	#33 INCREASE BUILDING RENT FROM AMS & ITC (H)	#34 NORMALIZE STUDY EXPENSE (I)	#35 ALLOCATION FACTOR ADJUSTMENT (J)
	PRODUCTION:									
	INCREMENTAL COSTS:									
1	LABOR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	FUEL (EXCL. W/H CR.)									
2	BASE LOAD	-	-	-	-	-	-	-	-	-
3	INTERCHANGE	-	-	-	-	-	-	-	-	-
4	FUEL ADDITIVES	-	-	-	-	-	-	-	-	-
	PURCHASED POWER									
	ENERGY									
5	BASE LOAD	-	-	-	-	-	-	-	-	-
6	INTERCHANGE	-	-	-	-	-	-	-	-	-
	CAPACITY COSTS		-	-	-	-	-	-	-	-
7	BASE LOAD	-	-	-	-	-	-	-	-	-
8	INTERCHANGE	-	-	-	-	-	-	-	-	-
9	OTHER	-	-	3,452	-	-	-	-	-	-
10	TOTAL PRODUCTION EXPENSES	-	-	3,452	-	-	-	-	-	-
	TRANSMISSION EXPENSES:									
11	LABOR	-	-	-	-	-	-	-	-	-
12	OTHER	-	-	275	-	-	-	4,067	-	-
13	TOTAL TRANSMISSION EXPENSES	-	-	275	-	-	-	4,067	-	-
	REGIONAL MARKET EXPENSES:									
14	LABOR	-	-	-	-	-	-	-	-	-
15	OTHER	-	-	-	-	-	-	-	-	-
16	TOTAL REGIONAL MARKET EXPENSES	-	-	-	-	-	-	-	-	-
	DISTRIBUTION EXPENSES:									
17	LABOR	-	-	-	-	-	-	-	-	-
18	OTHER	-	-	-	-	-	-	-	-	-
19	TOTAL DISTRIBUTION EXPENSES	-	-	-	-	-	-	-	-	-
	CUSTOMER ACCOUNTS EXPENSES:									
20	LABOR	-	-	-	-	-	-	-	-	-
21	OTHER	-	-	-	-	-	-	-	-	-
22	TOTAL CUSTOMER ACCOUNTS EXPENSES	-	-	-	-	-	-	-	-	-
	CUSTOMER SERV. & INFO. EXPENSES:									
23	LABOR	-	-	-	-	-	-	-	-	-
24	OTHER	-	-	-	-	-	-	-	-	-
25	TOTAL CUSTOMER SERV. & INFO. EXPENSES	-	-	-	-	-	-	-	-	-
	SALES EXPENSES:									
26	LABOR	-	-	-	-	-	-	-	-	-
27	OTHER	-	-	-	-	-	-	-	-	-
28	TOTAL SALES EXPENSES	-	-	-	-	-	-	-	-	-
	ADMINISTRATIVE & GENERAL EXPENSES:									
29	LABOR	-	-	-	-	-	-	-	-	-
30	OTHER	(3,042)	(8,433)	-	123	183	(566)	807	45	(817)
31	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**	(3,042)	(8,433)	-	123	183	(566)	807	45	(817)
32	**TOTAL OPERATIONS & MAINTENANCE EXPENSES**	**$ (3,042)**	**$ (8,433)**	**$ 3,727**	**$ 123**	**$ 183**	**$ (566)**	**$ 4,874**	**$ 45**	**$ (817)**

33 **NOTE:** See SCHEDULE SJH-D11-7 for explanation of the pro forma adjustments.

AMEREN MISSOURI
ELECTRIC OPERATING AND MAINTENANCE EXPENSES
PER BOOK AND PRO FORMA
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024 UPDATED THROUGH DECEMBER 31, 2024
($000)

LINE	FUNCTIONAL CLASSIFICATION (A)	#36 METER READS ADJUSTMENT (B)	#37 ELECTRIC COSTS ALLOC TO GAS (C)	#38 CUSTOMER CONVENIENCE FEES (D)	#39 RENEWABLE BTA COSTS ADJUSTMENT (E)	#40 CYBERSECURITY COSTS ADJUSTMENT (F)	#41 SOFTWARE MAINTENANCE ADJUSTMENT (G)	#42 NRC FEE ANNUALIZATION (H)	#43 NEW SOLAR FEES (I)	#44 ADVERTISING (J)
	PRODUCTION:									
	INCREMENTAL COSTS:									
1	LABOR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	FUEL (EXCL. W/H CR.)									
2	BASE LOAD	-	-	-	-	-	-	-	-	-
3	INTERCHANGE	-	-	-	-	-	-	-	-	-
4	FUEL ADDITIVES	-	-	-	-	-	-	-	-	-
	PURCHASED POWER									
	ENERGY									
5	BASE LOAD	-	-	-	-	-	-	-	-	-
6	INTERCHANGE	-	-	-	-	-	-	-	-	-
	CAPACITY COSTS									
7	BASE LOAD	-	-	-	-	-	-	-	-	-
8	INTERCHANGE	-	-	-	-	-	-	-	-	-
9	OTHER	-	-	-	5,695	-	-	2	2,429	-
10	TOTAL PRODUCTION EXPENSES	-	-	-	5,695	-	-	2	2,429	-
	TRANSMISSION EXPENSES:									
11	LABOR	-	-	-	-	-	-	-	-	-
12	OTHER	-	-	-	-	-	-	-	842	-
13	TOTAL TRANSMISSION EXPENSES	-	-	-	-	-	-	-	842	-
	REGIONAL MARKET EXPENSES:									
14	LABOR	-	-	-	-	-	-	-	-	-
15	OTHER	-	-	-	-	-	-	-	-	-
16	TOTAL REGIONAL MARKET EXPENSES	-	-	-	-	-	-	-	-	-
	DISTRIBUTION EXPENSES:									
17	LABOR	-	-	-	-	-	-	-	-	-
18	OTHER	-	-	-	-	-	-	-	-	-
19	TOTAL DISTRIBUTION EXPENSES	-	-	-	-	-	-	-	-	-
	CUSTOMER ACCOUNTS EXPENSES:									
20	LABOR	-	-	-	-	-	-	-	-	-
21	OTHER	(1,358)	-	283	-	-	-	-	-	-
22	TOTAL CUSTOMER ACCOUNTS EXPENSES	(1,358)	-	283	-	-	-	-	-	-
	CUSTOMER SERV. & INFO. EXPENSES:									
23	LABOR	-	-	-	-	-	-	-	-	-
24	OTHER	-	-	-	-	-	-	-	-	(689)
25	TOTAL CUSTOMER SERV. & INFO. EXPENSES	-	-	-	-	-	-	-	-	(689)
	SALES EXPENSES:									
26	LABOR	-	-	-	-	-	-	-	-	-
27	OTHER	-	-	-	-	-	-	-	-	-
28	TOTAL SALES EXPENSES	-	-	-	-	-	-	-	-	-
	ADMINISTRATIVE & GENERAL EXPENSES:									
29	LABOR	-	-	-	-	-	-	-	-	-
30	OTHER	-	35	-	-	19	1,014	91	-	-
31	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**	-	35	-	-	19	1,014	91	-	-
32	**TOTAL OPERATIONS & MAINTENANCE EXPENSES**	**$ (1,358)**	**$ 35**	**$ 283**	**$ 5,695**	**$ 19**	**$ 1,014**	**$ 93**	**$ 3,271**	**$ (689)**

33 **NOTE:** See SCHEDULE SJH-D11-7 for explanation of the pro forma adjustments.

SCHEDULE SJH-D11-5

AMEREN MISSOURI
ELECTRIC OPERATING AND MAINTENANCE EXPENSES
PER BOOK AND PRO FORMA
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024 UPDATED THROUGH DECEMBER 31, 2024
($000)

LINE	FUNCTIONAL CLASSIFICATION (A)	#45 NSR RESERVE (B)	#46 EV INCENTIVE ADJUSTMENT (C)	TOTAL PRO FORMA ADJUSTMENT (D)	PRO FORMA ELECTRIC TOTALS (E)
	PRODUCTION:				
	INCREMENTAL COSTS:				
1	LABOR	$ -	$ -	$ 12,751	$ 211,974
	FUEL (EXCL. W/H CR.)			-	
2	BASE LOAD	-	-	9,647	411,323
3	INTERCHANGE	-	-	20,289	71,085
4	FUEL ADDITIVES	-	-	506	7,196
	PURCHASED POWER			-	
	ENERGY				
5	BASE LOAD	-	-	10,239	109,834
6	INTERCHANGE	-	-	(14,663)	-
	CAPACITY COSTS				
7	BASE LOAD	-	-	241,999	364,623
8	INTERCHANGE	-	-	-	-
9	OTHER	-	-	(55,116)	151,930
10	TOTAL PRODUCTION EXPENSES	-	-	225,652	1,327,965
	TRANSMISSION EXPENSES:				
11	LABOR	-	-	200	6,630
12	OTHER	-	-	14,571	117,317
13	TOTAL TRANSMISSION EXPENSES	-	-	14,771	123,947
	REGIONAL MARKET EXPENSES:				
14	LABOR	-	-	-	-
15	OTHER	-	-	-	6,403
16	TOTAL REGIONAL MARKET EXPENSES	-	-	-	6,403
	DISTRIBUTION EXPENSES:				
17	LABOR	-	-	2,456	72,244
18	OTHER	-	-	(8,898)	86,437
19	TOTAL DISTRIBUTION EXPENSES	-	-	(6,442)	158,681
	CUSTOMER ACCOUNTS EXPENSES:				
20	LABOR	-	-	879	20,170
21	OTHER	-	-	3,789	38,423
22	TOTAL CUSTOMER ACCOUNTS EXPENSES	-	-	4,668	58,593
	CUSTOMER SERV. & INFO. EXPENSES:				
23	LABOR	-	-	158	8,375
24	OTHER	-	-	(73,389)	12,414
25	TOTAL CUSTOMER SERV. & INFO. EXPENSES	-	-	(73,232)	20,789
	SALES EXPENSES:				
26	LABOR	-	-	17	418
27	OTHER	-	-	-	23
28	TOTAL SALES EXPENSES	-	-	17	441
	ADMINISTRATIVE & GENERAL EXPENSES:				
29	LABOR	-	-	(1,577)	70,920
30	OTHER	(15,000)	4	(21,977)	81,200
31	**TOTAL ADMINISTRATIVE & GENERAL EXPENSES**	(15,000)	4	(23,554)	152,120
32	**TOTAL OPERATIONS & MAINTENANCE EXPENSES**	**$ (15,000)**	**$ 4**	**$ 141,881**	**$ 1,848,939**

33 **NOTE:** See SCHEDULE SJH-D11-7 for explanation of the pro forma adjustments.

SCHEDULE SJH-D11-6

AMEREN MISSOURI
ELECTRIC OPERATING AND MAINTENANCE EXPENSE
PRO FORMA ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	PRO FORMA ITEM NO. (A)	DESCRIPTION (B)	TOTAL AMOUNT (C)
1 2 3 4	(1)	Increased labor expense from annualizing the average 3.56% wage increase for management employees effective January 1, 2024, the 3.50% wage increase for the Company's union employees effective January 1, 2024 per the labor contracts, annualizing an average 3.10% wage increase for management employees effective January 1, 2025, and the 3.10% wage increase for the Company's union employees effective January 1, 2025.	$ 19,356
5 6	(2)	Decrease incentive compensation expense for the incentive compensation applicable to AMS and Ameren Missouri officers that is based on the achievement of earnings-per-share (EPS) goals of the Company.	$ (2,028)
7 8	(3)	Eliminate the long-term incentive compensation expense that is based on the achievement of total shareholder return (TSR) goals of the Company.	$ (7,346)
9 10	(4)	Increase in fuel expense to reflect the normalized sales and customer growth through December 31, 2024 reflecting January 2025 fuel prices.	$ 30,442
11 12	(5)	Increase in purchased power expense to reflect normalized sales and customer growth through December 30, 2024 and normalized power prices.	$ 247,070
13	(6)	Decrease in transmission expense related to Mark Twain Transmission project.	$ (108)
14	(7)	Increase in production expense to normalize steam plant maintenance.	$ 274
15	(8)	Decrease in production expense to remove a portion of production expense related to Rush Island Energy Center.	$ (2,552)
16	(9)	Decrease in production expense to remove a portion of production expense related to Meramec Energy Center.	$ (3,444)
17	(10)	Eliminate test year FAC recovery.	$ (50,958)
18 19	(11)	Increase in nuclear production expense to include the average annualized cost from the last 3 Callaway Nuclear Energy Center refueling outages.	$ 30,176
20	(12)	Decrease in nuclear production expense to eliminate the Callaway Nuclear Energy Center refueling amortization.	$ (34,133)
21	(13)	Decrease in production expense for amortization of RES cost regulatory liability.	$ (648)
22	(14)	Decrease in production expense for rebase of RES expenses.	$ (1,676)
23	(15)	Decrease in production expense to eliminate Solar Rebate amortizations in the test year.	$ (1,338)
24	(16)	Increase in production and distribution expenses for increase in depreciation charged to O&M.	$ 1,338
25	(17)	Decrease in distribution expense to normalize storm costs.	$ (3,103)
26	(18)	Decrease in distribution expense to normalize vegetation management and infrastructure inspection costs.	$ (5,450)
27	(19)	Increase in customer accounts expenses to reflect interest expense at 9.5% on the average customer deposit balance.	$ 2,789
28	(20)	Decrease in customer service expense to eliminate test year MEEIA program costs.	$ (71,459)
29	(21)	Increase in customer service expense from PAYS program amortization.	$ 97
30	(22)	Increase in administrative and general expense to normalize bad debt expense.	$ 2,075
31	(23)	Decrease in administrative and general expense for staffing annualization of salary and benefits.	$ (581)
32	(24)	Annualize insurance expense based upon current and expected insurance premiums.	$ 3,263
33 34	(25)	Increase in administrative and general expense to reflect annualized major medical and other employee benefit expenses through December 31, 2024.	$ 327
35	(26)	Increase non-qualified pension expense to reflect current level of expense.	$ 36
36	(27)	Rebase Pension and OPEB Tracker to true up level.	$ (3,042)
37 38	(28)	Decrease in administrative and general expense to reflect an increase in the amortization of the net regulatory liabilities for the Pension and OPEB Tracker.	$ (8,433)
39	(29)	Increase in production and transmission expense for base level expenses related to RESRAM.	$ 3,727
40 41	(30)	Increase in administrative and general expense to reflect the 6 case average of expenses to prepare and litigate a rate filing and to normalize this amount.	$ 123
42	(31)	Increase in administrative and general expense to annualize current level of MPSC Assessment.	$ 183
43	(32)	Decrease in administrative and general expense to remove certain Board of Director meeting expenses.	$ (566)
44	(33)	Increase in administrative and general expense for building rent from AMS and ITC.	$ 4,874
45	(34)	Increase in administrative and general expense to normalize depreciation study expense.	$ 45
46	(35)	Decrease in administrative and general expense to utilize 2024 allocation factors.	$ (817)
47	(36)	Decrease in customer accounts expense to reflect AMR cost savings partially offset by increasing AMI costs.	$ (1,358)
48	(37)	Increase in administrative and general expense for electric costs allocated to gas.	$ 35
49	(38)	Increase in customer accounts expense for customer convenience fees.	$ 283
50 51	(39)	Eliminate the impact to production expense from transferring costs related to solar generation investments to a balance sheet account, as these costs will be capitalized as part of the solar investments when the asset goes into service.	$ 5,695
52	(40)	Increase in administrative and general expense for an increase in cybersecurity costs.	$ 19
53	(41)	Increase in administrative and general expense for an increase in software maintenance costs.	$ 1,014
54	(42)	Increase in administrative and general and production expense for NRC fee annualization.	$ 93
55	(43)	Increase in production and transmission expense due to new solar facilities.	$ 3,271
56	(44)	Decrease in administrative and general expense to remove certain advertising expenses.	$ (689)
57	(45)	Decrease in administrative and general expense to remove NSR reserve.	$ (15,000)
58	(46)	Increase in administrative and general expense for the EV incentive program.	$ 4
59	**Total Pro Forma Adjustments to Electric Operating and Maintenance Expenses**		$ 141,881

AMEREN MISSOURI
DEPRECIATION & AMORTIZATION EXPENSE
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	DESCRIPTION (A)	TOTALS PER BOOKS (B)	PRO FORMA ADJUSTMENTS(1) (C)	PRO FORMA ELECTRIC TOTALS (D)
	DEPRECIATION EXPENSE:			
1	STEAM	211,399	(46,540)	164,859
2	NUCLEAR	82,232	16,632	98,864
3	CALLAWAY DECOMMISSIONING	6,759	-	6,759
4	HYDRAULIC	16,059	1,335	17,394
5	OTHER	65,994	38,469	104,463
6	TRANSMISSION PLANT	47,272	16,029	63,301
7	DISTRIBUTION PLANT	229,218	43,100	272,318
8	GENERAL PLANT	49,397	17,172	66,569
9	PISA	(16,049)	16,049	-
10	ICC DEPRECIATION	-	(1,886)	(1,886)
11	TOTAL DEPRECIATION EXPENSE	692,281	100,360	792,641
	PLANT AMORTIZATION:			
12	INTANGIBLE PLANT	126,690	(16,572)	110,118
13	HYDRAULIC PLANT	756	-	756
14	TRANSMISSION PLANT	445	-	445
15	GENERAL PLANT	-	-	-
16	PISA	(26,198)	26,198	-
17	TOTAL PLANT AMORTIZATION	101,693	9,626	111,319
	MISC. AMORTIZATION:			
18	CALLAWAY POST OPERATIONAL	3,687	(3,687)	-
19	CALLAWAY LIFE EXTEN AMORT	104	-	104
20	AMORT OF FUKUSHIMA STUDY COSTS	93	(93)	-
21	SIOUX SCRUBBER CONSTRUCTION ACCOUNTING	1,533	369	1,902
22	CUSTOMER AFFORDABILITY STUDY	(9,254)	11,431	2,177
23	AMORT. OF ENERGY EFFICIENCY REG ASSETS AND MEEIA ORDERED ADJ.	(7,177)	7,177	-
24	AMORT OF LOW INCOME SURCHARGE	2,094	31	2,125
25	EXPIRED & EXPIRING AMORTIZATIONS	(3,903)	2,976	(927)
26	PISA AMORTIZATION	-	33,282	33,282
27	EXCESS DEFERRED TRACKER AMORTIZATION	(11,942)	16,639	4,697
28	RESRAM ADJUSTMENTS	(41,981)	41,981	-
29	CHARGE AHEAD CORRIDOR	832	373	1,205
30	EQUITY ISSUANCE COST AMORTIZATION	-	1,256	1,256
31	MERAMEC RETIREMENT	12,184	-	12,184
32	MERAMEC INVENTORY WRITE-OFF	(7,524)	9,468	1,944
33	MERAMEC COAL INVENTORY WRITE-OFF	-	89	89
34	COVID AAO	986	761	1,747
35	CRITICAL NEEDS LOW INCOME PROGRAM	250	-	250
36	REHOUSING PILOT LOW INCOME PROGRAM	250	-	250
37	PROPERTY TAX TRACKER	-	7,836	7,836
38	KERSTING ESTATES REGULATORY ASSET	-	8	8
39	TOTAL MISC AMORTIZATION	(59,768)	129,897	70,129
40	TOTAL DEPR & AMORTIZATION EXPENSE	$ 734,206	$ 239,883	$ 974,089
41	(1) See SCHEDULE SJH-D12-2 for explanation of the pro forma adjustments.			

AMEREN MISSOURI
ELECTRIC DEPRECIATION & AMORTIZATION EXPENSE PRO FORMA ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	ITEM NO. (A)	DESCRIPTION (B)	PRO FORMA ADJUSTMENTS (C)
1	(1)	To reflect the book depreciation annualized for the plant in service depreciable balances at	
2		March 31, 2024 and additions to plant in service from April 2024 through December 2024 to	
3		reflect the true-up.	
4		Change in Depr. Exp. - Steam	$ (31,006)
5		Change in Depr. Exp. - Nuclear	3,089
6		Change in Depr. Exp. - Hydro	533
7		Change in Depr. Exp. - Other Prod.	37,967
8		Change in Depr. Exp. - Transmission	8,996
9		Change in Depr. Exp. - Distribution	24,576
10		Change in Depr. Exp. - General Plant	26,106
11		Change in Depr. Exp. - Incentive Comp Capitalized	(1,886)
12		Change in Amor. Exp. - Intangible Plant	(16,572)
13		Total Increase in Depreciation Expense	$ 51,803
14	(2)	To reflect change in depreciation rates per testimony of Gannett Fleming.	
15		Increase in Depr. Exp. - Steam	$ (13,713)
16		Increase in Depr. Exp. - Nuclear	13,543
17		Increase in Depr. Exp. - Hydro	802
18		Increase in Depr. Exp. - Other Prod.	502
19		Increase in Depr. Exp. - Transmission	7,033
20		Increase in Depr. Exp. - Distribution	18,524
21		Increase in Depr. Exp. - General Plant	2,679
22		Increase in Amort. Exp. - Intangible Plant	-
23		Total Increase in Depreciation Expense	$ 29,370
24	(3)	To eliminate PISA deferral.	
25		Depreciation	$ 16,049
26		Amortization	$ 26,198
27		Total Increase in Depreciation and Amortization Expense	$ 42,247
28	(4)	To reduce depreciation expense charged to O&M.	
29		Decrease in Depr. Exp. - Steam	$ (1,821)
30		Decrease in Depr. Exp. - General Plant	$ (11,613)
31		Total Decrease in Depreciation Expense	$ (13,434)
32	(5)	To eliminate the amortization of the Callaway Post Operational regulatory asset.	$ (3,687)
33	(6)	To eliminate the amortization of the Fukushima Study Costs.	$ (93)
34	(7)	To eliminate the amortizations of the Sioux Scrubber Construction Accounting contra regulatory	$ 369
35		assets and change amortization consistent with updated plant retirement.	
36	(8)	To reflect annualization of the amortization of the Customer Affordability regulatory asset and	$ 11,431
37		eliminate set-up of the regulatory asset.	
38	(9)	To eliminate the amortizations and deferrals made under the MEEIA Rider, including MEEIA	$ 7,177
39		ordered adjustments.	
40	(10)	To reflect annualization of amortization of Low Income Surcharge.	$ 31
41	(11)	To reflect Expired & Expiring Amortizations.	$ 2,976
42	(12)	To reflect amortization of PISA.	$ 33,282
43	(13)	To eliminate accumulation and reflect annualized amortization of Excess Deferred Tracker.	$ 16,639
44	(14)	To eliminate RESRAM activity.	$ 41,981
45	(15)	To reflect Charge Ahead Corridor amortization.	$ 373
46	(16)	To reflect amortization of the remaining Equity Issuance Costs regulatory asset over a period of	$ 1,256
47		5 years.	
48	(17)	To eliminate accumulation and reflect annualized amortization of Meramec Inventory.	$ 9,468
49	(18)	To reflect annualized amortization of remaining Meramec Coal Inventory.	$ 89
50	(19)	To reflect COVID AAO amortization.	$ 761
51	(20)	To amortize Property Tax Tracker.	$ 7,836
52	(21)	To amortize Kersting Estates regulatory asset.	$ 8
53	**TOTAL PRO FORMA ADJUSTMENTS: DEPRECIATION & AMORTIZATION**		$ 239,883

AMEREN MISSOURI
TAXES OTHER THAN INCOME TAXES
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	DESCRIPTION (A)	TOTAL PER BOOKS (B)	PRO FORMA ADJUSTMENTS(1) (C)	PRO FORMA ELECTRIC TOTALS (D)
	PAYROLL TAXES			
1	F.I.C.A.	$ 18,641	$ 1,103	$ 19,744
2	FEDERAL UNEMPLOYMENT	180	-	180
3	MISSOURI UNEMPLOYMENT	-	-	-
4	ILLINOIS UNEMPLOYMENT	24	-	24
5	IOWA UNEMPLOYMENT	6	-	6
6	OTHER STATES UNEMPLOYMENT	2	-	2
7	ST. LOUIS EMPLOYMENT TAX	345	-	345
8	TOTAL PAYROLL TAXES	19,198	1,103	20,301
	PROPERTY TAX			
9	MISSOURI R.E. & P.P.	177,457	5,069	182,526
10	ILLINOIS R.E. & P.P.	4,201	44	4,245
11	IOWA R.E. & P.P.	1,334	7	1,341
12	OTHER STATES R.E. & P.P.	11	12	23
13	R.E. TAXES CAPITALIZED	(7,345)	-	(7,345)
14	TRANSFER TO GAS	(274)	-	(274)
15	TRANSFER TO NON UTILITY	(83)	-	(83)
16	TOTAL PROPERTY TAXES	175,301	5,132	180,433
17	**MUNICIPAL GROSS RECEIPTS**	159,622	(159,622)	-
	MISCELLANEOUS			
18	ILLINOIS CORP FRANCHISE	107	-	107
19	FED. EXCISE TAX-HEAVY VEH. USE TAX	52	-	52
20	MISCELLANEOUS	274	-	274
21	TOTAL MISCELLANEOUS	433	-	433
22	**TOTAL TAXES OTHER THAN INCOME TAXES**	**$ 354,554**	**$ (153,387)**	**$ 201,167**

23 (1) See SCHEDULE SJH-D13-2 for explanation of the pro forma adjustments.

AMEREN MISSOURI
TAXES OTHER THAN INCOME
PRO FORMA ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	ITEM NO. (A)	DESCRIPTION (B)		PRO FORMA AMOUNT (C)
1	(1)	Increase F.I.C.A. taxes to reflect the pro forma wage adjustments.	$	1,103
2	(2)	Property tax true-up adjustment.		5,575
3	(3)	Eliminate the property taxes on future use plant, as this investment is	$	(443)
4		excluded from rate base.		
5	(4)	Eliminate gross receipts taxes as they are a pass through tax.	$	(159,622)
6		**Total Pro Forma Adjustments to Taxes Other Than Income**	$	(153,387)

AMEREN MISSOURI

TOTAL ELECTRIC INCOME TAXES AT THE PROPOSED RETURN
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	DESCRIPTION (A)	(B)	TOTAL ELECTRIC (C)
1	TOTAL ELECTRIC NET INCOME FROM OPERATIONS		$ 1,037,448
	ADD		
2	CURRENT INCOME TAXES		104,935
3	DEFERRED INCOME TAXES		
4	EXCESS DEFERRED INCOME TAX EXPENSE		(94,125)
5	I.T.C. AMORTIZATION		(2,763)
6	TOTAL ELECTRIC NET INCOME BEFORE INCOME TAX		1,045,495
	ADDITIONS TO NET INCOME BEFORE INCOME TAX		
7	BOOK DEPRECIATION		792,641
8	BOOK DEPRECIATION CHARGED TO O&M		5,614
9	INTANGIBLE AMORTIZATIONS		110,120
10	HYDRAULIC AMORTIZATIONS		756
11	TRANSMISSION AMORTIZATIONS		445
12	NONDEDUCTIBLE PARKING LOT EXPENSE		460
13	RSU's PERM ITEM		3,847
14	TOTAL ADDITIONS		913,883
	SUBTRACTIONS TO NET INCOME BEFORE INCOME TAX		
15	INTEREST ON DEBT (1)		286,778
16	TAX STRAIGHT LINE		892,001
17	NUCLEAR DECOMMISSIONING		6,759
18	PREFERRED DIVIDEND DEDUCTION		692
19	TOTAL SUBTRACTIONS		1,186,230
20	**TOTAL ELECTRIC NET TAXABLE INCOME**		**773,148**
	FEDERAL INCOME TAX		
21	NET TAXABLE INCOME		773,148
22	DEDUCT MISSOURI INCOME TAX		29,413
23	DEDUCT CITY EARNINGS TAX		105
24	FEDERAL TAXABLE INCOME		743,630
25	**FEDERAL INCOME TAX**	**21.00%**	156,162
	LESS TAX CREDITS		
26	RESEARCH CREDIT		1,844
27	PRODUCTION TAX CREDIT		78,903
28	**TOTAL ELECTRIC FEDERAL INCOME TAX**		**75,415**
	STATE INCOME TAXES		
29	NET TAXABLE INCOME		773,148
30	DEDUCT 50% OF FEDERAL INCOME TAX		37,708
31	DEDUCT CITY EARNINGS TAX		105
32	MISSOURI TAXABLE INCOME		735,335
33	**TOTAL ELECTRIC MISSOURI INCOME TAX**	**4.00%**	**29,414**
	CITY EARNINGS TAX		
34	NET TAXABLE INCOME		773,148
35	LESS TAX ADJUSTMENTS TO INCOME		(648,977)
36	CITY TAXABLE INCOME		124,171
37	CITY EARNINGS TAX	**0.0955%**	119
38	LESS: TAX CREDIT		14
39	**TOTAL ELECTRIC NET CITY EARNINGS TAX**		**105**
40	**TOTAL ELECTRIC CURRENT INCOME TAXES**		**104,934**
	DEFERRED INCOME TAXES:		
41	EXCESS DEFERRED INCOME TAX EXPENSE		(94,125)
42	I.T.C. AMORTIZATION		(2,763)
43	**TOTAL ELECTRIC DEFERRED INCOME TAX**		**(96,888)**
44	**TOTAL ELECTRIC CURRENT & DEFERRED INCOME TAX**		**$ 8,046**
45	(1) RATE BASE X EMBEDDED		
46	COST OF DEBT.	**2.045%**	

AMEREN MISSOURI
TOTAL ELECTRIC NET ORIGINAL COST RATE BASE AND REVENUE REQUIREMENT
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	DESCRIPTION (A)	REFERENCE (B)	TOTAL ELECTRIC AMOUNT (C)
	A. TOTAL ELECTRIC NET ORIGINAL COST RATE BASE		
1	ORIGINAL COST OF PLANT IN SERVICE	SCHEDULE SJH-D1	$ 25,703,855
2	LESS: RESERVES FOR DEPRECIATION & AMORTIZATION	SCHEDULE SJH-D2	9,946,209
3	NET ORIGINAL COST OF PLANT		15,757,646
4	AVERAGE FUEL AND MATERIALS AND SUPPLIES	SCHEDULE SJH-D3	605,957
5	AVERAGE PREPAYMENTS	SCHEDULE SJH-D4	27,835
6	CASH WORKING CAPITAL (LEAD/LAG)	SCHEDULE SJH-D5	(22,233)
7	FEDERAL INCOME TAX CASH REQUIREMENT	SCHEDULE SJH-D6	(202)
8	STATE INCOME TAX CASH REQUIREMENT	SCHEDULE SJH-D6	(79)
9	CITY EARNINGS TAX CASH REQUIREMENT	SCHEDULE SJH-D6	(68)
10	INTEREST EXPENSE CASH REQUIREMENT	SCHEDULE SJH-D6	(42,702)
11	AVERAGE CUSTOMER ADVANCES FOR CONSTRUCTION	SCHEDULE SJH-D7	(1,537)
12	AVERAGE CUSTOMER DEPOSITS	SCHEDULE SJH-D7	(29,356)
13	PENSION TRACKER	SCHEDULE SJH-D8	(60,210)
14	OPEB TRACKER	SCHEDULE SJH-D8	(17,453)
15	PAYS REGULATORY ASSET	SCHEDULE SJH-D8	1,710
16	PISA REGULATORY ASSET	SCHEDULE SJH-D8	611,655
17	MERAMEC RETIREMENT REGULATORY ASSET	SCHEDULE SJH-D8	33,512
18	EXPIRED & EXPIRING AMORTIZATIONS IN RATE BASE	SCHEDULE SJH-D8	(1,830)
19	PROPERTY TAX TRACKER	SCHEDULE SJH-D8	23,509
20	ACCUMULATED DEFERRED INCOME TAXES	SCHEDULE SJH-D9	(2,862,799)
21	**TOTAL ELECTRIC NET ORIGINAL COST RATE BASE**		**14,023,355**
	B. TOTAL ELECTRIC REVENUE REQUIREMENT		
	TOTAL ELECTRIC OPERATING EXPENSES:		
22	PRODUCTION	SCHEDULE SJH-D11-1	$ 1,327,965
23	TRANSMISSION	SCHEDULE SJH-D11-1	123,947
24	REGIONAL MARKET EXPENSES	SCHEDULE SJH-D11-1	6,403
25	DISTRIBUTION	SCHEDULE SJH-D11-1	158,681
26	CUSTOMER ACCOUNTS	SCHEDULE SJH-D11-1	58,593
27	CUSTOMER SERVICE	SCHEDULE SJH-D11-1	20,789
28	SALES	SCHEDULE SJH-D11-1	441
29	ADMINISTRATIVE AND GENERAL	SCHEDULE SJH-D11-1	152,120
30	TOTAL ELECTRIC OPERATING EXPENSES		1,848,939
31	DEPRECIATION AND AMORTIZATION	SCHEDULE SJH-D12-1	974,089
32	TAXES OTHER THAN INCOME TAXES	SCHEDULE SJH-D13-1	201,167
	INCOME TAXES-BASED ON PROPOSED RATE OF RETURN		
33	FEDERAL	SCHEDULE SJH-D14	75,415
34	STATE	SCHEDULE SJH-D14	29,414
35	CITY EARNINGS	SCHEDULE SJH-D14	105
36	TOTAL INCOME TAXES		104,934
	DEFERRED INCOME TAXES		
37	EXCESS DEFERRED INCOME TAX EXPENSE	SCHEDULE SJH-D14	(94,125)
38	I.T.C. AMORTIZATION	SCHEDULE SJH-D14	(2,763)
39	TOTAL DEFERRED INCOME TAXES		(96,888)
40	RETURN (RATE BASE * 7.398%)	**7.398%**	1,037,448
41	**TOTAL ELECTRIC REVENUE REQUIREMENT**		**$ 4,069,689**

AMEREN MISSOURI
INCREASE REQUIRED TO PRODUCE 7.398% RETURN ON
TOTAL ELECTRIC NET ORIGINAL COST RATE BASE
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024
($000)

LINE	DESCRIPTION (A)	TOTAL ELECTRIC AMOUNT (B)
1	**TOTAL ELECTRIC NET ORIGINAL COST RATE BASE**	**$ 14,023,355**
	TOTAL ELECTRIC REVENUE REQUIREMENT:	
2	RETURN AT PROPOSED RATE (7.398%)	1,037,448
3	OPERATING AND MAINTENANCE EXPENSES	1,848,939
4	DEPRECIATION AND AMORTIZATION	974,089
5	TAXES OTHER THAN INCOME TAXES	201,167
6	FEDERAL AND STATE INCOME AND CITY EARNINGS TAXES AT CLAIMED RETURN	104,934
7	DEFERRED INCOME TAXES	(96,888)
8	**TOTAL ELECTRIC REVENUE REQUIREMENT**	**4,069,689**
9	**PRO FORMA TOTAL ELECTRIC OPERATING REVENUE AT PRESENT RATES**	**3,623,491**
10	**DEFICIENCY IN TOTAL ELECTRIC OPERATING REVENUE**	**$ 446,198**

AMEREN MISSOURI
CALCULATION OF NET BASE ENERGY COST (BF)
FOR THE TWELVE MONTHS ENDED MARCH 31, 2024

LINE		DESCRIPTION	TOTAL	SUMMER	WINTER
		(A)	(B)	(D)	(E)
	A	**FUEL & PURCHASED POWER COSTS**			
		BASE LOAD			
1		FUEL FOR LOAD	404,754,376	163,174,000	241,580,376
2		FLY ASH (1)	(540,095)	(213,045)	(327,050)
3		FIXED GAS SUPPLY COSTS FOR LOAD (2)	7,108,584	2,538,606	4,569,978
4		FUEL ADDITIVES (2)	6,135,510	2,191,104	3,944,406
5		PURCHASED POWER FOR LOAD	110,138,556	31,697,000	78,441,556
6		TOTAL BASE LOAD	527,596,931	199,387,665	328,209,266
		OSS			
7		FUEL FOR LOAD	69,958,751	32,330,000	37,628,751
8		FLY ASH (1)	(93,351)	(36,823)	(56,528)
9		FIXED GAS SUPPLY COSTS FOR LOAD (2)	1,228,665	438,779	789,886
10		FUEL ADDITIVES (2)	1,060,477	378,716	681,761
11		PURCHASED POWER FOR LOAD	-	-	-
12		TOTAL OSS	72,154,542	33,110,672	39,043,870
13		**TOTAL FUEL AND PURCHASED POWER**	**599,751,473**	**232,498,337**	**367,253,136**
	B	**TRANSMISSION COSTS AND REVENUES**			
14		TRANSMISSION BY OTHERS (ACCT. 565 @1.65%) (2)	6,661,654	2,378,877	4,282,777
15		TRANMISSION REVENUES (ACC 456.1) (2)	(2,919,626)	(1,042,598)	(1,877,028)
16		**TOTAL TRANSMISSION COSTS AND REVENUES**	**3,742,028**	**1,336,279**	**2,405,749**
	C	**ADDITIONAL FUEL & PP COSTS**			
17		MISO DAY 2 EXCLUDING ADMIN (ACCT 555) (2)	(6,361,604)	(2,271,846)	(4,089,758)
18		COMMON BOUNDARY (2)	201,032	71,792	129,240
19		CAPACITY EXPENSE (2)	364,622,932	130,213,559	234,409,373
20		ANCILLARY SERVICES PURCHASED (ACCT. 555) (2)	4,342,937	1,550,863	2,792,074
21		PJM EXCLUDING ADMIN (ACCT. 555) (2)	119,615	42,714	76,901
22		REPLACEMENT POWER INSURANCE (ACC 925) (2)	945,953	337,800	608,153
23		**TOTAL ADDITIONAL FUEL & PP COSTS**	**363,870,864**	**129,944,882**	**233,925,982**
	D	**SALES**			
24		OFF-SYSTEM ENERGY SALES REVENUES (ACCT. 447)	131,914,838	72,327,000	59,587,838
25		MAKE WHOLE PAYMENT MARGINS (ACCT 447) (2)	863,069	308,218	554,851
26		CAPACITY SALES REVENUES (ACCT. 447) (2)	376,422,329	134,427,341	241,994,988
27		BILATERAL ENERGY SALES MARGINS (447) (2)	-	-	-
28		FINANCIAL SWAPS (ACCT 447) (2)	1,840,371	657,230	1,183,141
29		ANCILLARY SERVICES REVENUE (ACCT. 447) (2)	6,769,716	2,417,590	4,352,126
30		**TOTAL SALES**	**517,810,323**	**210,137,379**	**307,672,944**
	E	**OTHER ADJUSTMENTS**			
31		REAL-TIME LOAD AND GENERATION DEVIATION (2)	7,647,246	2,730,972	4,916,274
32		**TOTAL OTHER ADJUSTMENTS**	**7,647,246**	**2,730,972**	**4,916,274**
33	**A + B + C - D - E**	**NET BASE ENERGY COSTS**	**441,906,796**	**150,911,147**	**290,995,649**
34		**LOAD AT MISO CP NODE AMMO.UE (KWH)**	**32,403,411,327**	**11,571,854,538**	**20,831,556,789**
35		**BASE FACTOR (BF) ($ PER MWH)**	**13.64**	**13.04**	**13.97**
36		**BASE FACTOR (BF) (CENTS PER KWH)**	**1.364**	**1.304**	**1.397**

37 MONTHS IN EACH PERIOD:
38 SUMMER: JUNE THROUGH SEPTEMBER
39 WINTER: OCTOBER THROUGH MAY

40 (1) ALLOCATED BETWEEN SUMMER AND WINTERS BASED ON COAL FROM FUEL MODEL.
41 (2) ALLOCATED BETWEEN SUMMER AND WINTERS BASED ON LOAD.

AMEREN MISSOURI
CASH WORKING CAPITAL REQUIREMENT
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2020

Line No.	Description (A)	Revenue Lag (B)	Expense Lead (C)	Net Lag (D)	CWC Factor (E)
1	Pensions & Benefits	37.02	(15.70)	21.32	0.0584
2	Employee Benefits (Group Health & 401k)	37.02	(17.65)	19.37	0.0531
3	Payroll and Withholdings	37.02	(10.90)	26.12	0.0716
4	Payroll Taxes	37.02	(9.38)	27.64	0.0757
5	Other Operations and Maintenance Expenses	37.02	(42.25)	(5.23)	(0.0143)
6	Property/Real Estate Taxes	37.02	(183.00)	(145.98)	(0.3999)
7	Missouri Sales Tax	24.27	(4.50)	19.77	0.0542
8	Missouri and Iowa Use Tax	37.02	(76.25)	(39.23)	(0.1075)
9	Illinois Use Tax	37.02	(35.78)	1.24	0.0034
10	Gross Receipts Taxes	24.27	(26.99)	(2.72)	(0.0074)
11	Federal Income Tax	37.02	(38.00)	(0.98)	(0.0027)
12	State Income Tax	37.02	(38.00)	(0.98)	(0.0027)
13	St Louis Corporate Earnings Tax	37.02	(274.50)	(237.48)	(0.6506)
14	Fuel - Nuclear	37.02	(15.21)	21.81	0.0598
15	Fuel - Coal	37.02	(14.43)	22.59	0.0619
16	Fuel - Oil	37.02	(14.69)	22.33	0.0612
17	Fuel - Gas	37.02	(40.72)	(3.70)	(0.0101)
18	Interest Expense	37.02	(91.37)	(54.35)	(0.1489)
19	Uncollectible Expense	37.02	(37.02)	-	-
20	Purchased Power	37.02	(18.10)	18.92	0.0518
21	Decommissioning Fees	37.02	(69.50)	(32.48)	(0.0890)
22	Incentive Compensation	37.02	(250.80)	(213.78)	(0.5857)
23	Fed Excise Heavy Use Tax	37.02	125.57	162.59	0.4455
24	Self Procured Insurance Tax	37.02	(241.50)	(204.48)	(0.5602)
25	Ohio Commercial Activity Tax	37.02	50.00	87.02	0.2384
26	Corporate Franchise Tax	37.02	(233.19)	(196.17)	(0.5375)
27	State of Indiana Corporate Income Tax	37.02	(14.00)	23.02	0.0631
28	State of Iowa Corporate Income Tax	37.02	77.00	114.02	0.3124

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues for Electric Service.	)))	Case No. ER-2024-0319

AFFIDAVIT OF STEPHEN HIPKISS

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Stephen Hipkiss, being first duly sworn states:

My name is Stephen Hipkiss, and on my oath declare that I am of sound mind and lawful age; that I have prepared the foregoing *Direct Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Stephen Hipkiss
Stephen Hipkiss

Sworn to me this 27^{th} day of June, 2024.