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| Witness: | Mitchell J. Lansford |
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| Sponsoring Party: | Union Electric Company |
| File No.: | ER-2022-0337 |
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**MISSOURI PUBLIC SERVICE COMMISSION**

**FILE NO. ER-2022-0337**

# DIRECT TESTIMONY

# OF

# MITCHELL J. LANSFORD

# ON

# BEHALF OF

# UNION ELECTRIC COMPANY

# D/B/A AMEREN MISSOURI

**St. Louis, Missouri**
**August 2022**

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**DIRECT TESTIMONY**

**OF**

**MITCHELL J. LANSFORD**

**FILE NO. ER-2022-0337**

## I. INTRODUCTION

**Q. Please state your name and business address.**

A. My name is Mitchell Lansford. My business address is One Ameren Plaza, 1901 Chouteau Ave., St. Louis, Missouri.

**Q. By whom are you employed and what is your position?**

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

**Q. Please describe your educational background and employment experience.**

A. I received Bachelor of Science and Master's degrees in Accountancy from the University of Missouri at Columbia in 2008. I am a licensed Certified Public Accountant in the State of Missouri and a member of the American Institute of Certified Public Accountants. From 2008 to 2017, I worked for PricewaterhouseCoopers LLP, most recently as a Senior Manager in its assurance practice. In that capacity, I provided auditing and accounting services to clients, primarily in the utility industry. From 2017 to 2019, I worked for Ameren Services Company as the Manager of Accounting Research, Policy, and Internal Controls. My primary duties and responsibilities included accounting analysis for non-standard transactions, overseeing the implementation of new accounting guidance, implementation of new accounting policies, and assessments of the internal control environment. From 2019 to present, I have been working for Ameren Missouri in multiple regulatory accounting roles, including my current role as Director, Regulatory Accounting effective in April 2020.

**Q. What are your responsibilities in your current position?**

A. In my current position, my primary duties and responsibilities include preparation of the revenue requirement for Ameren Missouri rate filings, preparing written testimony for rate, regulatory, and audit proceedings, and testifying before the Missouri Public Service Commission.

## 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 "Company"). The revenue requirement determines the level of electric revenues required to pay operating expenses, to provide for depreciation and taxes, and to 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") tariff 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 MJL-D1 through MJL-D18.

**Q. What is the subject matter of these schedules?**

A. Schedules MJL-D1 through MJL-D18 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, 2022, with pro forma adjustments and updates for known and measurable changes to be trued-up through December 31, 2022. Schedule MJL-D17 reflects the calculation of net base energy costs ("NBEC") and the seasonal values for Factor BF in Rider FAC. Schedule MJL-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 MJL-D1 – Original Cost of Electric Plant by functional classification at March 31, 2022, per book and pro forma.
- Schedule MJL-D2 – Electric Plant Reserves for Depreciation and Amortization by functional classification at March 31, 2022, per book and pro forma.
- Schedule MJL-D3 – Average Fuel Inventories and Average Materials and Supplies Inventories at March 31, 2022, per book and pro forma applicable to electric operations.

- Schedule MJL-D4 – Average Pre-payments at March 31, 2022, per book and pro forma applicable to electric operations.
- Schedule MJL-D5 – Total Electric Cash Working Capital (per the Company's lead/lag study) for the twelve months ended March 31, 2022, applicable to electric operations.
- Schedule MJL-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 for the twelve months ended March 31, 2022.
- Schedule MJL-D7 – Average Electric Customer Advances for Construction and Average Electric Customer Deposit reductions to rate base at March 31, 2022.
- Schedule MJL-D8 – Regulatory Asset and Liability balances included in rate base at March 31, 2022, per book and pro forma.
- Schedule MJL-D9 – Total Electric Accumulated Deferred Income Taxes at March 31, 2022, per book and pro forma.
- Schedule MJL-D10 – Total Electric Operating Revenues for the twelve months ended March 31, 2022, per book and pro forma.
- Schedule MJL-D11 – Total Electric Operations and Maintenance Expenses, by functional classification, for the twelve months ended March 31, 2022, updated for certain known items, per book and pro forma. A description of each of the pro forma adjustment is included.

- Schedule MJL-D12 – Depreciation and Amortization Expenses applicable to electric operations, by functional classification, for the twelve months ended March 31, 2022, per book and pro forma. A description of each pro forma adjustment is included.
- Schedule MJL-D13 – Taxes Other Than Income Taxes, for the twelve months ended March 31, 2022, per book and pro forma for the electric operations of the Company. A description of each pro forma adjustment is included.
- Schedule MJL-D14 – Income Tax Calculation at the proposed rate of return and statutory tax rates for the total electric operations of the Company.
- Schedule MJL-D15 – The pro forma Electric Net Original Cost Rate Base at March 31, 2022, and Electric Revenue Requirement including the pro forma adjustments.
- Schedule MJL-D16 – The annual revenue increase required at a 7.186% return on Net Original Cost Electric Rate Base, including pro forma adjustments.
- Schedule MJL-D17 – Calculation of NBEC and seasonal values of Factor BF in Rider FAC.
- Schedule MJL-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, 2022 ("test year"), with pro forma adjustments to account for the true-up of various items through December 31, 2022 ("true-up date"), consistent with the approach used in the Company's nine previous rate reviews. The Company is proposing to true-up the following items: plant-in-service, depreciation reserve, materials and supplies (including fuel inventories), Meramec Energy Center closure materials and supplies net write-offs, 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, net energy costs (as defined in Rider FAC), Midcontinent Independent System Operator, Inc. ("MISO") transmission revenues and expenses, payroll, employment levels, other employee benefits, Renewable Energy Standard ("RES") costs, bad debt expense, Callaway re-fueling expenses, steam plant maintenance, storm costs, 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, lease expense, 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, MISO Schedule 26-A rates, and any wage increases that become effective on or before January 1, 2023. 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, 2022.

**Q. Why is it necessary to make pro forma adjustments to the test year data?**

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. Please explain Schedule MJL-D1.**

A. Schedule MJL-D1 shows the recorded original cost of electric plant by functional classification at March 31, 2021, along with the estimated plant additions and other adjustments through December 31, 2022, 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 Financial Accounting Standard ("FAS") 143 *Asset Retirement Obligations* ("ARO"), and the Accounting Standards Codification ("ASC") 842 *Leases* shown as the first adjustment on Schedule MJL-D1.**

A. FAS 143 is an accounting requirement to reflect the fact that the Company has an asset and corresponding legal obligation to remove certain facilities in the future. ASC 842 is an accounting 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 ($298,629,000) eliminates both the ARO and lease investments for ratemaking purposes.

**Q. Why is the Company including plant additions through December 31, 2022?**

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 important projects under the Smart Energy Plan in his direct testimony, and Company witness Ryan Arnold addresses specifically the Company's ongoing efforts to ensure the long-term reliability of its energy delivery system. In order to provide the Company 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 at the time new rates will become effective. Adjustment 2 adds the estimated plant-in-service additions, offset by retirements, of $1,416,558,000 from March 31, 2022, through December 31, 2022, which is the end of the proposed true-up period.

**Q. Please explain the adjustment for the Meramec Energy Center.**

A. The Company plans to retire the Meramec Energy Center in 2022, which is before new rates are expected to take effect in this case. Consistent with the Stipulation and Agreement from the Company's last rate review case, the Company will recover the stipulated amount for remaining normal non-labor plant operating costs not including any post-closure costs through rates over the five-year period beginning February 28, 2022.[1] Adjustment 3 reduces the plant-in-service balances by $684,510,000 for the expected retirement of the Meramec Energy Center, notwithstanding any post-closure costs capitalized or expected to be capitalized by the true-up date.

**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 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 $17,454,000 and $25,204,000, respectively.

[1] File No. ER-2021-0240, Unanimous Stipulation and Agreement, p. 4, para. 9, filed November 24, 2021.

**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 the compensation has been capitalized and added to plant-in-service. Adjustment 5 reduces the plant-in-service balance by $57,165,000 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 MJL-D1, the total electric plant-in-service is $22,883,458,000.

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

A. Similar adjustments were made to the accumulated reserve balance of plant-in-service. Adjustment 1 eliminates $80,752,000 from the depreciation reserve related to FAS 143 ARO and ASC 842 Leases.

Adjustment 2 increases the depreciation reserve by $549,802,000 to reflect depreciation through the true-up date on plant-in-service investments existing at March 31, 2022.

Adjustment 3 increases the depreciation reserve by $18,976,000 to reflect the depreciation related to pro forma net additions to plant-in-service from March 31, 2022, through December 31, 2022, the proposed true-up period.

Adjustment 4 reduces the depreciation reserve by $671,227,000 for the previously described adjustment related to the expected upcoming retirement of the Meramec Energy Center. In accordance with the Stipulation and Agreement in File No. ER-2021-0240, post-closure removal costs capitalized after September 30, 2021, remain in rate base.

Adjustment 5 eliminates the accumulated depreciation and amortization reserve of $5,187,000 for the multi-use General Plant applicable to gas operations. Adjustment 5 also eliminates $11,138,000 of the accumulated amortization related to Intangible Plant applicable to gas operations. This adjustment corresponds to Adjustment 4 made to plant-in-service on Schedule MJL-D1.

Accumulated depreciation and amortization reserve is reduced by $15,784,000 in Adjustment 6 to reflect the accumulated depreciation and amortization applicable to a portion of capitalized incentive compensation reflected in Adjustment 5 in Schedule MJL-D1.

The pro forma accumulated provision for depreciation and amortization, as shown in Schedule MJL-D2, applicable to total plant-in-service is $9,221,601,000.

**Q. Please explain Schedule MJL-D3.**

A. Schedule MJL-D3 shows the average investment in fuel inventories, materials and supplies at March 31, 2022. Fuel 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 include such items 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.

At the current time, the Company is experiencing coal delivery problems in receiving necessary shipments from the railroads. This is resulting in a continued decline in inventory for the coal-fired energy centers. Therefore, coal inventory levels during the test year are not representative of levels expected once rates set in this case take effect. Even though some problems started being experienced January 2021, thirteen-month average inventory levels from the previous rate review at September 31, 2021, are being used to normalize this problem. Rail delivery problems are discussed in Company witness Andrew Meyer's direct testimony. The thirteen-month average coal inventory has been increased by $24,780,000 to reflect the January 1, 2023, coal price per ton in pro forma Adjustment 1.

Adjustment 2 shown in Schedule MJL-D3 reduces general materials and supplies and coal inventory included in rate base by $13,653,000 to reflect the upcoming retirement of the Meramec Energy Center. There is no coal inventory or materials and supplies inventory for the Meramec Energy Center included in the Company's revenue requirement.

Adjustment 3 shown in Schedule MJL-D3 removes the portion of the average general materials and supplies inventory of $2,114,000 applicable to the Company's gas operations.

**Q. Are there any other inventory adjustments necessary at the true-up date?**

A. Yes. Upon retirement and closure of the Company's Meramec Energy Center, a materials and supplies inventory write-off is expected for inventoried items necessary to maintain reliable operations but no longer necessary after retirement.[2] The Company requests authority to defer these write-offs and amortize and recover these costs over a two-year period beginning with the implementation of new customer rates in this rate review.

**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 MJL-D3, is $567,950,000.

**Q. Please explain the average pre-payments shown in Schedule MJL-D4.**

A. Certain costs for items such as rent, insurance, service agreements, medical and dental voluntary employee beneficiary association ("VEBA") contributions, digital subscriptions, and others are paid in advance. After elimination of amounts applicable to gas operations, the thirteen-month average balance of total electric pre-payments at March 31, 2022, is $16,327,000.

**Q. Please explain Schedule MJL-D5.**

A. Schedule MJL-D5 shows the calculation of the electric cash working capital requirement as a negative net cash requirement of ($15,778,000), 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.

[2] Net of any salvage proceeds.

**Q. What appears on Schedule MJL-D6?**

A. The interest expense, federal income tax, Missouri income tax, Indiana income tax, Iowa income tax, and St. Louis earnings tax cash requirements applicable to the Company's electric operations are shown in Schedule MJL-D6. The payment lead times for these items are based on actual or statutory due dates.

**Q. What is the cash requirement for interest expense, federal income taxes, Missouri income taxes, Indiana income taxes, Iowa income taxes and St. Louis earnings taxes?**

A. Reflecting the payment lead times for each of these items compared to the revenue lag results in negative cash requirements of ($32,161,000) for interest expense, ($189,000) for federal income taxes, ($64,000) for state income taxes, and ($89,000) for city earnings tax. The cash requirements for Indiana income taxes and Iowa income taxes are zero because these taxes were not incurred during the twelve months ended March 31, 2022.

**Q. What items are shown in Schedule MJL-D7?**

A. The thirteen-month average balances at March 31, 2022, for electric customer advances for construction and electric customer deposits are shown in Schedule MJL-D7. These items represent cash provided by customers that can be used by the Company until they are refunded. Therefore, the average balances for the 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 $546,000 at March 31, 2022.

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 accounting expense in Schedule MJL-D11. The thirteen-month average balance of electric customer deposits was $18,816,000 at March 31, 2022.

**Q. What is shown in Schedule MJL-D8?**

A. Schedule MJL-D8 shows the pension and OPEB regulatory liability balances, the plant-in-service accounting ("PISA") regulatory asset balance, the PAYS regulatory asset, the Meremac Retirement asset, and a regulatory asset representing the impact of continued amortization for balances expected to be fully amortized, or near fully amortized, at the time new rates are expected to go into effect.

The pension and OPEB regulatory liability balances are shown for the period ended March 31, 2022, and further amortized through the true-up date. In File No. ER-2021-0240, the pension and OPEB tracker expenses accumulated from January 1, 2020, through September 30, 2021, were set to amortize over a five-year period scheduled to end in February 2027. Prior tracked amounts were established in prior rate reviews and set to amortize over three- or five-year periods. Amortization calculations in prior rate reviews were based on expected customer rate implementations on the operation of law dates in those cases. However, some prior rate reviews have resulted in earlier rate implementations and further resulted in amortization amounts that will not result in the full amortization of remaining balances over the specified term. As a result, the Company proposes that all pension and OPEB deferrals established in prior rate reviews, and not yet fully recovered or refunded, are amortized over two years beginning with the effective date of new customer rates in this rate review. Doing so will accelerate refunds to customers, eliminate historical tracking complexities, and correct amortization calculations based on implementation dates that differed from the operation of law date in past rate reviews. Refund of this net regulatory liability over two years is appropriate given the recent Company history of filing rate reviews approximately every two years. For clarity, deferrals established in this rate review should continue to be amortized over five years. $39,679,776 is the expected net regulatory liability and rate base reduction at December 31, 2022, reflecting the details of this proposal.

Schedule MJL-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. In File No. ER-2019-0335, a regulatory asset was established for PISA accumulations from September 1, 2018, to December 31, 2019. This regulatory asset is being amortized over the 20-year period ending May 31, 2040. In File No. ER-2021-0240, a regulatory asset was established for PISA accumulations from January 1, 2020, to September 30, 2021. This regulatory asset is being amortized over the 20-year period ending March 31, 2042. A third regulatory asset has been established for PISA accumulations from October 1, 2021, to December 31, 2022, and will be amortized over 20 years. The total PISA regulatory asset balance of $394,572,000 reflects the deferral made, and estimated, under PISA on or after September 1, 2018, through December 31, 2022, 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, 2022) shall be included in the participating utility's rate base.

In the Unanimous Stipulation and Agreement in File No. EO-2018-0211, the Company agreed to include the PAYS-financed regulatory asset in rate base in future rate reviews. $1,861,000 is the total deferrals made under the PAYS program less any amortization recorded, or expected to be recorded by December 31, 2022, since the Company's prior rate review.

The Meramec Retirement asset was established in the Unanimous Stipulation and Agreement from File No. ER-2021-0240.[3] 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. These costs are recovered over five years, instead of less than one year, as a way to keep customer rates affordable for the Company's customers. The overwhelming majority of the costs giving rise to this deferral are those that should be included in rate base (e.g., depreciation). Accordingly, the remaining unrecovered Meramec Retirement asset is included in rate base.

In the Unanimous Stipulation and Agreement in File No. ER-2016-0179,[4] the Company agreed that the balance of each amortization relating to regulatory assets or liabilities that remain, after full recovery by the Company (regulatory asset) or full credit to the Company's customers (regulatory liability), shall be applied as offsets to other amortization which do not expire before the Company's new rates from this general rate

[3] *Id.*
[4] File No. ER-2016-0179, Unanimous Stipulation and Agreement, filed February 23, 2017.

proceeding take effect. The agreement also provides that if no other amortization expires before the Company's new rates take effect, then the remaining unamortized balance of any regulatory asset or liability that did not expire before new rates take effect shall be a new regulatory liability or asset that is amortized over an appropriate period. Finally, the Company agreed that any over or under-recovery of the regulatory asset or liability will be treated in the same manner as the underlying asset or liability, meaning that if the underlying regulatory asset or liability was included in rate base, the over or under-recovery shall also be included in rate base, but if the underlying regulatory asset or liability was not included in rate base neither shall the over or under-recovery. The Company proposes to continue that approach in this case.

In accordance with the above-referenced File No. ER-2021-0240 Stipulation and Agreement, a regulatory asset of $161,000 increases 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 operation of law date in this case (or soon after). The combined over or under-recovery of such regulatory assets and liabilities expected through December 31, 2022, has also been included in this adjustment. Refer to the discussion of Schedule MJL-D12 below for the inventory of regulatory assets and liabilities that are expected to expire prior to when new rates from this general rate proceeding take effect and, therefore, have been combined.

**Q. Please explain Schedule MJL-D9.**

A. Schedule MJL-D9 lists the accumulated deferred income taxes applicable to total electric operations at March 31, 2022, and the pro forma adjustments required to project the balances forward to December 31, 2022, the end of the proposed true-up period.

Accumulated deferred income taxes are 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 MJL-D9, the total electric pro forma accumulated deferred income tax balance is a net liability balance of $2,968,208,000. 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 March 31, 2022?**

A. The Company's total electric rate base as shown in Schedule MJL-D15 is $11,605,779,000.

**Q. Please explain Schedule MJL-D10.**

A. Schedule MJL-D10 shows total electric operating revenues per book and pro forma for the twelve months ended March 31, 2022, with customer growth and other pro forma adjustments through December 31, 2022, the end of the proposed true-up period.

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

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

Adjustment 1 eliminates revenue add-on taxes of $143,699,000, as they are directly passed through to customers by the Company; Adjustment 2 eliminates the Missouri Energy Efficiency Investment Act ("MEEIA") revenues of $135,558,000, as they are collected through the MEEIA Rider rather than through base rates. Adjustment 3 eliminates FAC revenues of $88,220,000, as they are collected through the FAC Rider rather than base rates. Adjustment 4 eliminates the effect of unbilled revenues and decreases revenues by $22,430,000. After the unbilled revenue adjustment, book revenues are reflected on a bill cycle basis. Because new retail rates (resulting from File No. ER-2021-0240) were effective February 28, 2022, Adjustment 5 increases revenues by $214,415,000 to annualize the effect of those new rates to the full test year. Adjustment 6 removes $676,000 of revenues as a result of the economic development incentive adjustment ("EDI"), an adjustment made to account for base rate revenues that were not 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 $221,000 to reflect revenues expected to be received as part of the Company's Community Solar Program. Adjustment 8 increases revenues by $5,893,000 to reflect estimated customer growth through December 31, 2022. Adjustment 9 reduced revenues by $1,531,000 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 $16,225,000 in Adjustment 10. Since the Company uses cycle and window billing, revenues are increased by $8,567,000 to reflect the twelve-month billing year as a twelve-month, 365-day, calendar year in Adjustment 11. Adjustment 12 increases revenues by $12,594,000 to synchronize the book revenues with the Company's billing unit rate analysis. Revenues were decreased in Adjustment 13 by $29,185,000 to reflect normal weather. Revenue adjustments 5, 6, 7, 8, 10, 11, 12, and 13 are further discussed by Company witness Nicholas Bowden in his direct testimony.

The provision for rate refunds of $23,766,000, applicable to the operation of the Company's FAC, is eliminated in Adjustment 14.

The "other electric revenues" in Schedule MJL-D10 were increased by $348,000 in Adjustment 15 for estimated transmission revenues through December 31, 2022, the proposed true-up date. IRS Section 45 Refined Coal Credits expired and, therefore, revenues are reduced by $311,000 to remove this expiring source of revenue in Adjustment 16. Adjustment 17 decreases other revenue by $2,151,000 to annualize late fee revenues to levels based on the agreed upon late payment fee rate established in File No. ER-2021-0240. Adjustment 18 decreases other revenue by $87,950,000 for non-recurring insurance recoveries related to the unplanned outage at the Callaway Energy Center that began in December 2020. Adjustment 19 increases revenue by $196,000 to reflect expected additional intercompany facility rental revenue. In Adjustment 20, the Company is decreasing revenues by $922,000 because certain software assets will be fully amortized prior to true-up date and therefore will no longer be a source of rental revenue. In Adjustment 21, revenues were decreased by $375,000 to reflect the cancelation of the Bank of America building lease. Adjustment 22 increases revenue by $19,000 for annual revenues expected at the true-up date under the PAYS program. Adjustment 23 eliminates revenue add-on taxes of $1,027,000 applicable to other revenues, as they are directly passed through to customers from other revenues by the Company.

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

A. Yes, Adjustment 25 in Schedule MJL-D10 increases the actual off-system sales revenues from energy by $56,291,000 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 Meyer. Adjustment 26 increases sales of capacity by $211,108,000, 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 March 31, 2022?**

A. The pro forma electric operating revenues for the twelve months ended March 31, 2022, are $3,312,063,000, including the off-system sales revenues.

**Q. Please describe what is shown in Schedule MJL-D11.**

A. Total electric O&M for the twelve months ended March 31, 2022 (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 MJL-D11.

**Q. Please explain the pro forma adjustments to electric O&M for the twelve months ended March 31, 2022.**

A. A summary of the pro forma adjustments to O&M appears in Schedule MJL-11. Adjustment 1 reflects the increased labor expenses related to union and management wage increases at January 1, 2022, and January 1, 2023. A 2.5% wage increase for union employees was effective January 1, 2022, per the labor contracts. A 2.25% wage increase for management employees was effective January 1, 2022. In addition, the Company expects union and management employee to receive average wage increases of 3.75% effective January 1, 2023. The annualized increase in the total electric operating labor expense resulting from wage increases is $17,728,000. These wage increases reflect known and measurable changes that 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 by $1,969,000 to eliminate the incentive compensation that is based on the achievement of earnings-per-share goals of the Company and, for remaining incentive compensation not eliminated, adjust to payments made under the plans in 2022.

Consistent with prior cases, long-term incentive compensation related to the Company's earnings-per-share goals is eliminated. $6,438,000 applicable to the Company, including the allocated Ameren Services Company amount, is eliminated from O&M in Adjustment 3. Beginning in 2018, Ameren's long-term incentive compensation plan called for each award to be payable approximately 70% in Performance Share Units that adjust for performance relative to the Company's earnings-per-share goals and 30% payable in

Restricted Share Units, which do not adjust for Company performance. Restricted Share Units represent the right to receive stock depending solely on an employees continued employment with the Company through a defined vesting period. Restricted Share Unit costs relating to compensation paid out in March 2022 are included in the Company's revenue requirement.

Adjustment 4 reflects a decrease in O&M expense of $11,886,000 for fuel expense and was 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.

Adjustment 5 is an increase in O&M expense of $200,766,000 to reflect purchased power expense based on the normalized billed kWh sales and output with customer growth through December 2022, and normalized power prices.

The increases and decreases in the O&M expenses contained in Adjustment 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 expense by $125,000 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, 2022.

Adjustment 7 decreases O&M expenses by $29,000 to remove the portion of membership dues associated with lobbying activities that were inadvertently recorded above-the-line in the test year.

Adjustment 8 removes reductions in O&M expenses related to the previously discussed IRS Section 45 Refined Coal Credits and increases production expense by $15,105,000.

Adjustment 9 increases O&M expense by $1,496,000 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. This adjustment 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 10 reduces O&M expenses by $2,539,000 to reflect reduced operations of the Rush Island Energy Center expected to result from New Source Review litigation.

Adjustment 11 reduces the O&M expense by $1,443,000 to adjust non-labor O&M expenses at the Meramec Energy Center to expected amounts necessary for post-closure activities.

Adjustment 12 decreases O&M expense by $102,847,000 to eliminate the FAC recovery during the test year, as these costs are recovered under the FAC Rider rather than base rates.

Adjustment 13 is an increase to O&M expense 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 annual amount of operations and maintenance expenses, it is necessary to include two-thirds (12-month annual period for setting rates as compared to the 18-month outage cycle) of Callaway Energy Center re-fueling expenses. Further variability exists in the level of expenses incurred during a re-fueling outage. This adjustment also reflects normalization of costs by averaging the costs of the past three Callaway re-fueling outages. Production expenses must be increased by $22,715,000 for non-labor maintenance expense and $5,262,000 for incremental overtime expenses. Adjustment 13 results in a total increase of $27,977,0000.

Adjustment 14 is a decrease in O&M expense of $27,887,000 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 13 and 14 is an increase in O&M expense of $90,000.

Adjustment 15 decreases O&M by $968,000 to eliminate test year non-labor O&M expenses associated with the unplanned outage at the Callaway Energy Center that began in December 2020.

Adjustment 16 increases O&M expense by $3,902,000 to eliminate amortization of the RES regulatory liability balances established in prior cases and recover remaining costs over a three-year period.

Adjustment 17 increases O&M expense by $1,962,000 to re-base expenses related to the RES Tracker, including the Maryland Heights Renewable Energy Center fuel costs.

Adjustment 18 decreases O&M expense by $978,000 to eliminate pre-RESRAM solar rebate costs and amortization from the test year.

Adjustment 19 increases the O&M expense by $1,338,000 for the amortization and recovery of  pre-RESRAM solar rebates over a three-year period.

Adjustment 20 decreases O&M expense by $825,000 for a decrease in depreciation that is charged to O&M expense for coal cars, transportation, and heavy-duty equipment. Depreciation expense charged to O&M expense was updated for investment levels at December 31, 2022, and depreciation rates proposed in this rate review.

Adjustment 21 decreases O&M expense by $5,330,000 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 22 is an increase to O&M expenses to reflect interest expense at 4.25% on the average customer deposit balance. The average customer deposit balance at March 31, 2022, is deducted from rate base. The interest expense added to the customer accounting expense is $800,000.

Adjustment 23 decreases O&M expenses by $73,388,000 to eliminate program costs related to MEEIA, which are included in the MEEIA Rider.

Adjustment 24 increases O&M expense by $163,000 for the annual amortization of the PAYS regulatory assets expected at the true-up date. This adjustment includes annualization of the amortization authorized in File No. ER-2021-0240 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 25 increases O&M by $3,572,000 to annualize bad debt expense to the level of bad debt net write-offs from the test year. Test year bad debt expense was significantly impacted by incremental accruals recorded in 2020 that did not result in write-offs, at least in part as a result of payment assistance programs offered, administered, or enabled by the Company in response to the Covid-19 pandemic.

The various insurance policies of the Company are renewable at different times during a year. Adjustment 26 increases the O&M expense by $3,018,000 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.

Adjustment 27 increases O&M expenses by $975,000 to reflect increases in the other employee benefits expense to annualize the employee benefits expense through December 31, 2022, the proposed true-up date.

O&M expense is decreased by $148,000 in Adjustment 28 to annualize the cost of the non-qualified pension plan, which is no longer in the pension tracker, to reflect the annualized calendar year 2022 level of expense.

Adjustment 29 decreases O&M expense by $27,901,000 to rebase the pension and OPEB tracker to reflect applicable annualized calendar year 2022 expense levels.

Adjustment 30 increases O&M expenses by $2,498,000 to reflect the annualized amortization of the pension and OPEB net regulatory balances, and the estimated net regulatory liability balances at December 31, 2022, the end of the proposed true- up period.

Adjustment 31 increases O&M expense by $3,892,000 for expected non-labor O&M costs included in the RESRAM base amount. This rebasing adjustment reflects, in part, the expected annual operations and maintenance expenses at the Company's wind energy centers as of the true-up date.

O&M expenses are decreased in Adjustment 32 by $136,000 to reflect the average rate review expenses incurred by the Company in the last five general rate reviews and recovery of these costs over a two-year period.

Adjustment 33 decreases O&M expenses by $232,000 to annualize the most recent Ameren Missouri electric operations commission assessment.

In Adjustment 34, the Company eliminated $422,000 of O&M expenses for certain Ameren Corporation Board of Directors meeting expenses and Company chartered flight expenses.

Depreciation Study expenses will be recovered over five years based on the requirement for a study to be completed every five years, which results in the decrease to O&M expenses of $48,000 shown in Adjustment 35.

Adjusted 36 increases O&M expenses by $80,000 to annualize the increase in building rent expense allocated to Ameren Missouri from Ameren Services Corp.

Adjusted 37 decreases O&M expenses by $710,000 to eliminate costs related to recently exited facilities, including the Bank of America building lease and the Sunset Hills Office.

Adjustment 39 increases O&M expenses by $554,000 to annualize applicable expenses based on current allocation factors.

Adjustment 40 decreases O&M expenses by $2,373,000 to annualize the reduction in meter reading fees based on expected progress in the Company's advanced metering infrastructure deployment at December 31, 2022.

Adjustment 41 decreases O&M expenses by $6,274,000 related to the costs incurred during the test year for a study of customer affordability opportunities. Total non-labor costs associated with this study are amortized over a period of 5 years to better align recovery of these costs with the timing of the benefits enabled by the study. Refer to the discussion below regarding Schedule MJL-D12 (adjustment 8) for the impact of the amortization related to this study.

Adjustment 42 decreases O&M expenses by $3,434,000 to remove costs associated with the Company's renewable energy transition that were inadvertently recorded to expense during the test year.

Adjustment 43 increases O&M expenses by $15,000 for identified electric costs which were allocated to gas operations in the test year.

Adjustment 44 increases O&M expense by $3,849,000 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 change was implemented on February 28, 2022, and, therefore, this adjustment reflects an annualization of the expense necessary for a full 12 months.

Adjustment 45 increases O&M expense by $345,000 for expected annual cybersecurity costs through December 31, 2022, the proposed true up period.

Cybersecurity costs are expected to continue to increase as the Company responds to the expanding threat landscape.

Adjustment 46 decreases O&M expense by $277,000 for expected annual software maintenance expenses through December 31, 2022, the proposed true up period.

Adjustment 47 increases O&M expense by $377,000 to annualize fees associated with the Nuclear Regulatory Commission.

Adjustment 48 increases O&M expense by $384,000 to include in the test year a normal level of audit finding arising from recurring sales and use tax audits.

Adjustment 49 increases O&M expense by $1,000 for electric vehicle incentive costs which were inappropriately allocated to gas operations in the test year.

**Q. Are there any other O&M adjustments necessary at the true-up date?**

A. At this time the Company is aware of one additional adjustment and that is an adjustment to current employment levels that exist at the true up date. This type of adjustment has been made in the past several Company rate reviews, because employment levels are a significant factor in determining the Company's costs. This relationship still exists. The Company considered estimating the expected employment levels in its direct case, but due to higher levels of uncertainty than normal in the current labor markets, concluded a reasonable estimate could not be made at this time. The actuals will be trued-up as part of the true-up process.

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

A. As shown in Schedule MJL-D11, the total electric O&M expenses are increased from $1,734,030,000 to $1,746,221,0000, or a total net increase of $12,191,000 by the above pro forma adjustments.

**Q. What is shown in Schedule MJL-D12?**

A. Schedule MJL-D12 shows the total electric depreciation and amortization expenses by functional classifications for the twelve months ended March 31, 2022, per book and pro forma through the true-up date.

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

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

Adjustment 1 increases depreciation and plant amortization by $73,818,000 to reflect the book depreciation annualized for the plant-in-service depreciable balances at March 31, 2022, and plant additions through the true-up period, based on the depreciation rates approved in File No. ER-2021-0240.

Depreciation and plant amortization expenses are increased by $24,056,0000 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 $93,964,000 to eliminate PISA depreciation and amortization deferrals from the test year ended March 31, 2022.

The depreciation expenses for coal cars (Account 312), transportation equipment (Account 392), and heavy-duty equipment (Account 396) are not charged to depreciation expense. Adjustment 4 reduces depreciation expense by $12,652,000 to eliminate depreciation expense on these accounts.

Adjustment 5 increases amortization expense by $1,341,000 to eliminate annual amortization of the construction accounting contra regulatory asset for the Sioux Scrubbers. The contra regulatory asset account is recorded for Generally Accepted Accounting Principles ("GAAP") purposes and has no impact on ratemaking in the State of Missouri. This adjustment also includes an increase in amortization of the regulatory asset for the construction accounting of the Sioux Scrubbers to reflect a retirement date of 2030.

Adjustment 6 increases amortization by $519,000 to eliminate the amortization recorded in the test year related to balances that were subsequently combined and netted in File No. ER-2021-0240.

Adjustment 7 decreases amortization by $17,438,000 to eliminate MEEIA deferrals and amortizations that are considered under the MEEIA Rider, including MEEIA ordered adjustments.

Adjustment 8 increases amortization expense by $1,926,000 for the amortization and recovery of costs for a study of customer affordability opportunities. This study was conducted in support of the Company's efforts toward reaching its customer affordability goals. Company witness Wood discuss the Company's affordability efforts in his direct testimony. It is appropriate to amortize total non-labor costs associated with this study over a period of 5 years to better align recovery of these costs with the timing of the benefits supported by the study.

Adjustment 9 increases amortization expense by $917,000 to annualize the $2,000,000 above-the-line spend for the Keeping Current and Keeping Cool Program. This adjustment reflects a continuation of the $4,000,000 funding level agreed to and approved in File No. ER-2021-0240, split evenly between customers and the Company.

As previously referenced, the Company has combined and netted regulatory assets and liabilities expected to expire prior to, or soon after, the date new rates are expected to become effective in this rate review. Any over or under-recovery that will exist at the date new rates are expected to become effective in this rate review will be tracked, combined, and netted for the following balances:

| Balance Description | July 1, 2023 Balance (Projected) |
|---|---|
| Expired & Expiring Amortizations – Rate Base ER-2021-0240 under-recovery | $130,000 |
| Expired & Expiring Amortizations – Non-Rate Base ER-2021-0240 over-recovery | $(4,784,000) |
| Federal Income Tax Rate Change – Stub Period under-recovery | $1,438,000 |
| Total over-recovery | $(3,215,000) |

These tracked, combined, and netted balances will be amortized over a three-year period. Adjustment 10 increases amortization by $3,345,000 to amortize the combined and netted over- and under-collections associated with expired and expiring regulatory balances.

Adjustment 11 increases amortization by $20,497,000 for the amortization of PISA deferrals over twenty-year periods.

Adjustment 12 decreases amortization by $10,829,000 to eliminate deferrals under the excess deferred taxes tracker and amortize the accumulated balance over a three-year period.

Adjustment 13 decreases amortization by $5,475,000 to eliminate deferrals made under the RESRAM and eliminate amortization associated with amounts recovered through the associated RESRAM rider.

Adjustment 14 increases amortization by $953,000 to recover the Charge Ahead Corridor Program regulatory asset over a seven-year period.

Adjustment 15 decreases amortization by $760,000 to reflect the two-year amortization of refunds from the FERC Return on Equity ("ROE") complaint case. Refund of this regulatory liability over two years is appropriate given the recent Company history of filing rate reviews approximately every two years.

Adjustment 16 increases amortization by $1,181,000 to recover the COVID-19 Accounting Authority Order deferral resulting from File No. ER-2021-0240 over a three-year period.

Adjustment 17 increases amortization by $1,782,000 to reflect amortization of the equity 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 beginning with new rates effective February 28, 2022, consistent with Staff's proposal in File No. ER-2021-0240.[5]

Adjustment 18 increases amortization by $17,260,000 to reflect full refund of the Tax Cuts and Jobs Act Stub Period regulatory liability.

Adjustment 19 increases amortization expense by $229,000 to annualize the $250,000 above-the-line spend for the Critical Needs Low Income program. This adjustment reflects the establishment of the $500,000 funding level agreed to and approved in File No. ER-2021-0240, split evenly between customers and the Company.

Adjustment 20 increases amortization expense by $229,000 to annualize the $250,000 above-the-line spend for the Rehousing Pilot Low Income program. This adjustment reflects the establishment of the $500,000 funding level agreed to and approved in File No. ER-2021-0240, split evenly between customers and the Company.

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

A. As reported in Schedule MJL-D12, the total electric pro forma depreciation and amortization expenses are $847,997,000.

**Q. Please explain Schedule MJL-D13.**

A. Schedule MJL-D13 shows taxes other than income taxes for the twelve months ended March 31, 2022, per book and pro forma.

[5] File No. ER-2021-0240, Staff Direct Cost of Service Report, p.180.

**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 MJL-D13.**

A. The following pro forma adjustments detailed in Schedule MJL-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 $997,000 to reflect pro forma wage adjustments.

Adjustment 2 increases property taxes by $3,625,000 to reflect property taxes expected to be paid in December 2022.

Property taxes of $302,000 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 included in rate base.

Adjustment 4 adjusts taxes other than income taxes to remove Missouri gross receipts taxes of $145,597,000, 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. Is the Company implementing the Property Tax Tracker newly established by Section 393.1275, RSMo.?**

A. Yes. Section 393.1275, RSMo., adopted by the Missouri General Assembly and signed into law by Governor Parson this year (effective August 28, 2022) establishes a property tax tracker for various utilities, including Ameren Missouri. To more easily administer the tracker by starting on the first day of an accounting month, the Company will begin tracking applicable amounts on September 1, 2022, and include deferrals made under the tracker in its true-up revenue requirement.

**Q. Over what period should Property Tax Tracker deferrals be recovered or refunded?**

A. The Company recommends recovery or refund of tracked amounts over two years given the recent Company history of filing rate reviews approximately every two years.

Q. **Are there any further adjustments to taxes other than income taxes to consider before the true-up date?**

A. Yes. Uncertainty exists as to whether and how St. Louis City employment taxes should be applied for certain employees. The Company will monitor this expense through the true-up date and may make any further necessary adjustments at that time.

**Q. How much are pro forma taxes other than income taxes for the twelve months ended March 31, 2022, for total electric?**

A. As reflected in Schedule MJL-D14, the pro forma total electric taxes other than income taxes are $194,072,000.

**Q. What is shown in Schedule MJL-D14?**

A. Schedule MJL-D14 shows the derivation of the income tax calculation at the requested 7.186% 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 7.186% rate of return.

**Q. As shown in Schedule MJL-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 $94,292,000 for total electric operations, as shown in Schedule MJL-D14. Deferred income taxes for total electric operations of ($88,881,000) are also shown in Schedule MJL-D14. Net current and deferred income taxes for electric operations are $5,411,000.

**Q. Please explain Schedule MJL-D15.**

A. Schedule MJL-D15 shows the total electric rate base of $11,605,779,000 and the total electric revenue requirement of $3,627,692,000 at the requested return of 7.186%.

**Q. What does Schedule MJL-D16 reflect?**

A. Schedule MJL-D16 compares the total electric revenue requirement of $3,627,692,000 with the total electric pro forma operating revenues under the present rates of $3,312,063,000, including off-system energy sales revenues. It shows that the revenue requirement for the test year is $315,629,000 more than the pro forma operating revenues at present rates. $3,627,692,000 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?**

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 1.448 cents per kilowatt-hour for the summer and 1.312 cents per kilowatt-hour for the winter. Schedule MJL-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 segregated between the summer and winter periods to develop two separate values under Rider FAC. Per Schedule MJL-D17, the summer net base energy cost of $168,947,047 was then divided by the normalized Ameren Missouri summer load at the MISO Node AMMO.UE of 11,670,000,000 kWhs to arrive at a summer value expressed in centers per kWh of 1.448 cents. The winter net base energy cost of $273,499,514 was then divided by the normalized Ameren Missouri winter load at the MISO Node AMMO.UE of 20,840,188,374 kWhs to arrive at a winter value expressed in cents per kWh of 1.312 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 File No. ER-2021-0240 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.[6] 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)

[6] Such proceedings include File Nos. ER-2010-0036 (AmerenUE), ER-2008-0318 (AmerenUE), ER2007-0291 (Kansas City Power & Light Company), ER-2008-0093 (The Empire District Electric Company), GR-2007-0208 (Laclede Electric Company), and GR-2006-0422 (Missouri Electric 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 and as required under its contract with the Pioneer Prairie Wind Farm. 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 remaining balance due. Taking this information into account, a weighted expense lead time of 9.31 days was determined.

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.

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 Taxes.

**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 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 MJL-D18.**

A. Schedule MJL-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 continuation or establishment of five trackers: the pension and OPEB expense tracker, the RES tracker, the FIN48 tracker, the excess deferred tax amortization tracker (all of which are existing), and the new statutory property tax tracker. My testimony also includes the amortization of existing regulatory assets and liabilities. As summarized in Schedule MJL-D16, the Company's total electric revenue requirement, including the Company's proposed 7.186% return on rate base is more than the pro forma operating revenues at the present rates by $315,629,000. Consequently, rates should be designed to increase revenues by $315,629,000, 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 MJL-D18, reflecting a re-base of net base energy costs.

**Q. Does this conclude your direct testimony?**

A. Yes, it does.

**BEFORE THE PUBLIC SERVICE COMMISSION**
**OF THE STATE OF MISSOURI**

| | | |
|---|---|---|
| In the Matter of Union Electric Company<br>d/b/a Ameren Missouri's Tariffs to Adjust<br>Its Revenues for Electric Service. | )<br>)<br>) | Case No. ER-2022-0337 |

**AFFIDAVIT OF MITCHELL J. LANSFORD**

| | |
|---|---|
| **STATE OF MISSOURI** | **)** |
| | **) ss** |
| **CITY OF ST. LOUIS** | **)** |

Mitchell Lansford, being first duly sworn states:

My name is Mitchell J. Lansford, 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/ Mitchell J. Lansford*
Mitchell J. Lansford

Sworn to me this 1st day of August, 2022.