Exhibit No. 4

Ameren Missouri – Exhibit 4
Mitchell Lansford
Direct Testimony
File Nos. ER-2021-0240 & GR-2021-0241

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Witness:	Mitchell Lansford
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2021-0240

DIRECT TESTIMONY

OF

MITCHELL LANSFORD

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
March 2021

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DIRECT TESTIMONY

OF

MITCHELL LANSFORD

FILE NO. ER-2021-0240

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.

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, to provide for depreciation and taxes, and to give investors an opportunity to earn a fair and reasonable return on their investment. Ameren Missouri 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 Ameren Missouri'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 Ameren Missouri'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 December 31, 2020, with pro forma adjustments and updates for known and measurable changes to be trued-up through September 30, 2021. 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 December 31, 2020, per book and pro forma.
- Schedule MJL-D2 – Electric Plant Reserves for Depreciation and Amortization by functional classification at December 31, 2020, per book and pro forma.
- Schedule MJL-D3 – Average Fuel Inventories and Average Materials and Supplies Inventories at December 31, 2020, per book and pro forma applicable to electric operations.
- Schedule MJL-D4 – Average Pre-payments at December 31, 2020, 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 December 31, 2020, 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 December 31, 2020.
- Schedule MJL-D7 – Average Electric Customer Advances for Construction and Average Electric Customer Deposit reductions to rate base at December 31, 2020.
- Schedule MJL-D8 – Regulatory Asset and Liability balances included in rate base at December 31, 2020, per book and pro forma.
- Schedule MJL-D9 – Total Electric Accumulated Deferred Income Taxes at December 31, 2020, per book and pro forma.
- Schedule MJL-D10 – Total Electric Operating Revenues for the twelve months ended December 31, 2020, per book and pro forma.
- Schedule MJL-D11 – Total Electric Operations and Maintenance Expenses ("O&M"), by functional classification, for the twelve months ended December 31, 2020, 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 December 31, 2020, 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 December 31, 2020, 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 December 31, 2020, and Electric Revenue Requirement including the pro forma adjustments.
- Schedule MJL-D16 – The annual revenue increase required at a 6.995% 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 is the sum of O&M 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 ended December 31, 2020 ("test year"), with pro forma adjustments to account for the true-up of various items through September 30, 2021 ("true-up date"), consistent with the approach used in the Company's eight previous rate cases. 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, net energy costs (as defined in Rider FAC), Midcontinent Independent System Operator, Inc. ("MISO") transmission revenues and expenses, compensation, number of employees, employee benefits, Renewable Energy Standard ("RES") costs, Callaway re-fueling expenses, Callaway unplanned outage expenses, Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") costs, insurance expenses, Company Owned Life Insurance ("COLI") investment gains and losses, Pay as You Save® ("PAYS®") amounts, COVID-19 deferrals, the Missouri Public

Service Commission ("MPSC") assessment, lease expense, capital structure, equity issuance costs, depreciation expense, 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 September 30, 2021. 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 September 30, 2021.

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.

Q. Please explain Schedule MJL-D1.

A. Schedule MJL-D1 shows the recorded original cost of electric plant by functional classification at December 31, 2020, along with the estimated plant additions and other adjustments through September 30, 2021, 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 a legal obligation to remove certain facilities in the future. Since Ameren Missouri is regulated and collects or expects to collect funds to cover removal costs through its rates, no return on AROs are required for ratemaking purposes.

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 ($328,534,000) eliminates both the ARO and lease investments for ratemaking purposes.

Q. Why is the Company including plant additions through September 30, 2021?

A. The Company continues to spend significant amounts on infrastructure replacements and improvements, including investments being made as part of its Smart Energy Plan, and new renewable energy wind facilities both to comply with Missouri's Renewable Energy Standard and as part of the transition of its generation fleet to more renewable sources of power. 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 $1,303,470,000 from January 2021 through September 30, 2021, 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 less than a year after new rates are expected to take effect in this case. Accordingly, and consistent with principles that underlie the approach taken regarding the treatment of costs related to Evergy's Sibley plant and its retirement, the Company proposes to recover the remaining Meramec Energy Center costs through rates over a five-year period starting with the effective date of new rates to be set in this case. To implement this approach, adjustment 3 reduces the plant-in-service balances by $549,866,000. For clarity, all amounts relating to the Meramec Energy Center that are included in the revenue requirement, except those captured in the Company's FAC, reflect one-fifth of the amounts that would otherwise be included in this revenue requirement. The other impacted components of the revenue requirement, which will be referenced further throughout this testimony, are plant reserve, accumulated deferred income taxes, coal inventory, general materials and supplies inventory, O&M expenses, and depreciation. Further, by making these adjustments the allowed return and income taxes are also reduced. Cumulative adjustments relating to the Meramec Energy Center total a reduction of $55,456,000 to the Company's revenue requirement as compared to what it would have been had Meramec's operations been included in the revenue requirement in full. Recovery of one-fifth of the total remaining Meramec Energy Center revenue requirement of $69,321,000 results in the inclusion of $13,864,000 in this revenue requirement.

Q. Is the Company requesting accounting authorization to implement this approach?

A. Yes. The Company requests approval of a Meramec Energy Center Retirement Tracker to ensure that this significant retirement does not benefit or harm any party through regulatory lag. As noted, implementation of such a tracker is, in many ways, similar to the treatment ordered by the Commission relating to the retirement of Evergy's Sibley Plant.

Q. Should any amounts relating to the proposed Meramec Energy Center Retirement Tracker be included in the Company's rate base?

A. Yes. Any amount included in rate base in this revenue requirement and relating to the Meramec Energy Center should be considered the base amount for the rate base component of the proposed tracker. Any difference between the rate base component of the base amount included in this revenue requirement and related future actual costs should be deferred and included in rate base in the Company's future rate cases, until fully recovered or refunded.

Q. Should carrying costs be applied to any deferrals made under the Meramec Energy Center Retirement Tracker?

A. Yes. Carrying costs equal to the Company's weighted-average-cost-of-capital should be applied to deferrals included in rate base. Carrying costs equal to the Company's short-term borrowing rate should be applied to deferrals excluded from rate base.

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 applicable to the Company's gas operations of $14,461,000 and $19,290,000, 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 recovery was not requested. 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 $48,056,000 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 $21,185,206,000.

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 $102,230,000 from the depreciation reserve related to FAS 143 ARO and ASC 842 Leases.

Adjustment 2 increases the depreciation reserve by $503,151,000 to reflect depreciation through the true-up date on plant-in-service investments existing at December 31, 2020.

Adjustment 3 increases the depreciation reserve by $19,369,000 to reflect the depreciation related to pro forma net additions to plant-in-service from January 1, 2021 through September 30, 2021, the proposed true-up period.

Adjustment 4 reduces the depreciation reserve by $487,732,000 for the previously described adjustment related to the upcoming retirement of the Meramec Energy Center.

Adjustment 5 eliminates the accumulated depreciation and amortization reserve of $4,311,000 for the multi-use General Plant applicable to gas operations. Adjustment 5 also eliminates $6,320,000 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 $14,612,000 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 $8,805,955,000.

Q. Please explain Schedule MJL-D3.

A. Schedule MJL-D3 shows the average investment in fuel inventories, materials and supplies at December 31, 2020. Fuel consists of nuclear fuel, coal, minor amounts of oil and stored natural gas used for electric generation, emissions allowances, and renewable energy credits. 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 and coal inventory relating to the Meramec Energy Center. An eighteen-month average is used for the nuclear fuel since the Callaway Energy Center is re-fueled every eighteen months. As previously described, amounts related to the Meramec Energy Center have been adjusted for implementation of the proposed tracker.

The actual thirteen-month average coal inventory has been increased by $509,000 to reflect the September 30, 2021 coal price per ton in pro forma Adjustment 1.

Adjustment 2 shown in Schedule MJL-D3 reduces coal inventory and general materials and supplies included in rate base by $12,813,000 for the previously described adjustment related to the upcoming retirement of the Meramec Energy Center.

Adjustment 3 shown in Schedule MJL-D3 removes the portion of the average general materials and supplies inventory of $2,204,000 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 MJL-D3, is $509,137,000.

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. The thirteen-month average balance of total electric pre-payments at December 31, 2020 of $16,719,000 is used, after eliminating the portion applicable to gas operations.

Q. Please explain Schedule MJL-D5.

A. Schedule MJL-D5 shows the calculation of the electric cash working capital requirement as a negative cash requirement of ($16,026,000), which is based on a lead/lag study for the twelve months ended December 31, 2020, including the pro forma adjustments to the operating expenses. I will explain the details of the lead/lag study later in this testimony.

Q. What appears on Schedule MJL-D6?

A. The interest expense cash requirement, federal income tax cash requirement, Missouri income tax cash requirement, Indiana income tax cash requirement, Iowa income tax cash requirement, and St. Louis earnings tax cash requirement 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 ($27,269,000) for interest expense, ($95,000) for federal income taxes, ($48,000) for state income taxes, and ($51,000) for city earnings tax. The cash requirements for Indiana income taxes and Iowa income taxes are $3,000 and $9,000, respectively.

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

A. The thirteen-month average balances at December 31, 2020 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 $1,696,000 at December 31, 2020.

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 $25,001,000 at December 31, 2020.

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, and a regulatory liability 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 December 31, 2020 and further amortized through the true-up date. In File No. ER-2019-0335, (Ameren Missouri's most recent electric rate case), the pension and OPEB tracker expenses accumulated from January 1, 2017 through December 31, 2019 were set to amortize over a five-year period scheduled to end in March 2025. The pension and OPEB tracker balances originally established in File No ER-2016-0179 were re-set to a new five-year amortization period scheduled to end in March 2025. The pension and OPEB tracker balances originally established in File No. ER-2014-0258 were not amortized. The pension and OPEB tracker balances originally established in File No. ER-2012-0166, for the period from March 2011 through July 2012 were re-set, with a new three-year amortization period scheduled to end in March 2023.

The pension and OPEB tracker balances originally established in File No. ER-2019-0335 and File No. ER-2016-0179 are being amortized over a new five-year period in this revenue requirement. The pension and OPEB liabilities established in ER-2014-0258 and ER-2012-0166 are being amortized over a new three-year period. In addition, the estimated pension and OPEB tracker expenses accumulated from January 1, 2020 through the true-up date are also included with one-fifth of the net regulatory asset and liability balance at September 30, 2021 being included in the revenue requirement in this case, reflecting amortization over a period of five years. The pension and OPEB trackers are estimated to have net regulatory liability balances at September 30, 2021. The net balance of the pension tracker and the OPEB tracker is a regulatory liability of $32,197,000. As the net of these items is a regulatory liability, rate base is reduced by that amount.

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. In File No. ER-2019-0335, a regulatory asset balance was established for the PISA accumulation from September 1, 2018 to December 31, 2019. This accumulation began to be amortized over a 20-year period in that case. A second PISA accumulation then began and the rate base amount will be established by this case and amortized over 20 years. The PISA regulatory asset balance of $242,925,000 reflects the deferral made, and estimated, under PISA on or after September 1, 2018 through September 30, 2021, 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., September 30, 2021) shall be included in the participating utility's rate base.

In the Unanimous Stipulation and Agreement in File No. EO-2018-0211,[1] the Company agreed to include the PAYS-financed regulatory asset in rate base in future rate cases. Inclusion of the PAYS-financed regulatory asset expected at the true-up date increases Ameren Missouri's rate base by $3,044,000.

In the Unanimous Stipulation and Agreement in File No. ER-2016-0179,[2] the Company agreed that the balance of each amortization relating to regulatory assets or liabilities that remain, after full recovery by Ameren Missouri (regulatory asset) or full credit to Ameren Missouri's customers (regulatory liability), shall be applied as offsets to other amortization which do not expire before Ameren Missouri's new rates from this general rate proceeding take effect. The agreement also provides that if no other amortization expires before Ameren Missouri'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

[1] File No. EO-2018-0211, Unanimous Stipulation and Agreement Regarding the Implementation Certain MEEIA Programs Through Plan Year 2022, filed July 10, 2020.
[2] File No. ER-2016-0179, Unanimous Stipulation and Agreement, filed February 23, 2017.

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 File No. ER-2019-0335 Non-Unanimous Stipulation and Agreement,[3] a regulatory liability of $749,000 decreases Ameren Missouri'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 September 30, 2021 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 December 31, 2020, and the pro forma adjustments required to project the balances forward to September 30, 2021, 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-

[3] File No. ER-2019-0335, Non-Unanimous Stipulation and Agreement, filed February 28, 2020.

tax income. An additional pro forma adjustment in the amount of $141,000 reduces net accumulated deferred income tax liabilities related to the previously discussed Meramec Energy Center adjustment.

Currently, the Company has deferred income taxes in Federal Energy Regulatory Commission 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 $2,994,782,000. 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 December 31, 2020?

A. The Company's total electric rate base as shown in Schedule MJL-D16 is $10,053,174,000, and consists of:

	In Thousands of $
Original Cost of Plant-In-Service	$21,185,206
Less Reserve for Depreciation & Amortization	8,805,955
Net Original Cost of Plant	12,379,251
Average Fuel, Materials & Supplies	509,137
Average Pre-payments	16,719
Cash Working Capital (Lead/Lag)	(16,026)
Federal Income Tax Cash Requirement	(95)
State Income Tax Cash Requirements	(36)
City Earnings Tax Cash Requirement	(51)
Interest Expense Cash Requirement	(27,269)
Average Customer Advances for Construction	(1,696)
Average Customer Deposits	(25,001)

Pension Tracker Regulatory Asset	(24,996)
OPEB Tracker Regulatory Liability	(7,201)
PAYS Regulatory Asset	3,044
PISA Regulatory Asset	242,925
Under Collect Amortizations in Rate Base	(749)
Accumulated Deferred Income Taxes	(2,994,782)
Total Electric Rate Base	$10,053,174

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 December 31, 2020, with customer growth through September 30, 2021, 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 $133,114,000, as they are directly passed through to customers by the Company; Adjustment 2 eliminates the Missouri Energy Efficiency Investment Act ("MEEIA") revenues of $90,051,000, as they are collected through the MEEIA Rider rather than through base rates. Since the Company is re-basing the net base energy costs in the FAC, it is appropriate to eliminate the revenues impact from the FAC recoveries. Adjustment 3 eliminates the FAC revenue impact by increasing revenues by $47,583,000. Adjustment 4 eliminates the effect of unbilled revenues and increases revenues by $7,432,000. After the unbilled revenue adjustment, book revenues are reflected on a bill cycle basis. Adjustment 5 increases revenues by $12,831,000 to normalize depressed revenues due to the impact of the initial shock of the

COVID-19 pandemic. Because new retail rates (resulting from File No. ER-2019-0335) were effective April 1, 2020, Adjustment 6 decreases revenues by $2,189,000 to annualize the effect of those new rates to the full test year. Adjustment 7 removes $179,000 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 8 increases revenues by $8,834,000 to reflect estimated customer growth through September 30, 2021. Adjustment 9 reduced revenues by $11,460,000 to remove revenues recovered under the RESRAM. Due to the impact of energy efficiency efforts and solar programs, revenues are being reduced by $17,582.000 in Adjustment 10. Since the Company uses cycle and window billing, revenues are decreased by $3,148,000 to reflect the twelve month billing year as a twelve month, 365 day, calendar year in Adjustment 11. Adjustment 12 decreases revenues by $656,000 to synchronize the book revenues with the Company's billing unit rate analysis. Revenues were increased in Adjustment 13 by $9,863,000 to reflect normal weather. Revenue adjustments 5, 6, 7, 8, 9, 11, 12, and 13 are further discussed by Ameren Missouri witness Nicholas Bowden in his direct testimony.

The provision for rate refunds of $43,975,000, applicable to the operation of the Company's FAC, is eliminated in Adjustment 14. Since the Company is re-basing the net base energy costs in its FAC, it is appropriate to eliminate the provision for rate refunds.

The "other electric revenues" in Schedule MJL-D10 were increased by $522,000 in Adjustment 15 for estimated transmission revenues through September 30, 2021, the proposed true-up date. IRS Section 45 Refined Coal Credits expire before new rates are expected to become effective in this case and, therefore, revenues are reduced by $1,385,000 to remove this expiring source of revenue in Adjustment 16. During the test year, the Company implemented a temporary policy to waive late payment and disconnections fees to ease customers' burden during the COVID-19 pandemic. Adjustment 17 increases other revenue by $4,464,000 to normalize these fee revenues to 2019 levels (the most recently completed calendar year unaffected by the COVID-19 pandemic). In Adjustment 18, the Company is decreasing revenues by $1,544,000 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 19, revenues were decreased by $1,687,000 to reflect the cancelation of the Bank of America building lease. Adjustment 20 increases revenue by $385,000 for annual revenues expected at the true-up date under the PAYS® program.

In Adjustment 21, the losses of less than $1,000 recognized in the disposition of emissions allowances are eliminated as a non-recurring item.

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

A. Yes, Adjustment 22 in Schedule MJL-D10 increases the actual off-system sales revenues from energy by $149,189,000 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 Ameren Missouri witness Andrew Meyer. Adjustment 23 increases sales of capacity by $5,933,000, to reflect a normal level of capacity sales, as is also addressed in Mr. Meyer's direct testimony. The production cost model ("PowerSimm"), explained in the direct testimony of Ameren Missouri 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, 2020?

A. The pro forma electric operating revenues for the twelve months ended December 31, 2020 are $2,913,055,000, including the off-system sales revenues.

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

A. Total electric O&M expenses for the twelve months ended December 31, 2020 (per books by functional classification), the pro forma electric O&M 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 December 31, 2020.

A. A summary of the pro forma adjustments to O&M appears in Schedule MJL-11. Adjustment 1 reflects the increased labor expenses from annualizing the 2.5% wage increase for the Company's union employees effective January 1, 2021, per the labor contracts. In addition, management employees' average wage increase of 1.83% effective January 1, 2021 has also been reflected. The annualized increase in the total electric operating labor expense resulting from wage increases is $7,203,000. These wage increases reflect known and measurable changes that occurred 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 $4,110,000 to eliminate the incentive compensation related to earnings of Ameren Services Company officers allocated to Ameren Missouri and the Ameren Missouri officers, as well as to represent the amounts paid in the test year.

Consistent with prior cases, long-term incentive compensation related to Ameren Corporation's financial performance of $4,318,000 applicable to Ameren Missouri, 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 are related to financial performance of Ameren Corporation and 30% payable in Restricted Share Units, which are not related to financial performance. Restricted Share Units represent the right to receive stock depending solely on an employees continued employment with Ameren through a defined vesting period. Restricted Share Unit costs relating to compensation paid out in March 2021 are included in this pro forma adjustment, partially offsetting the noted reduction.

Adjustment 4 increases salaries and benefits expense by $11,731,000 to reflect expected staffing increases of 232 full-time equivalents through September 30, 2021, the proposed true-up period. 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.

Adjustment 5 reflects the increase in O&M expense of $64,978,000 for the normalized billed kilowatt-hour ("kWh") sales and output with customer growth through September 30, 2021, reflecting contracted-for fuel prices at the true-up date.

Adjustment 6 is a decrease in O&M expense of $7,104,000 to reflect the normalized billed kWh sales and output with customer growth through September 2021, and normalized power prices.

The increases and decreases in the O&M expenses contained in Adjustment 5 and 6 were calculated by Mr. Peters using the PowerSimm production cost model. His direct testimony details the inputs and assumptions used in the PowerSimm model. The purchased power expenses also include the power market and ancillary services changes from MISO.

Adjustment 7 reduces O&M expense by $160,000 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 December 31, 2020. Adjustments will be made in future general rate proceedings for the post-December 31, 2020 charges per the above-referenced orders.

Adjustment 8 removes O&M amounts related to the previously discussed IRS Section 45 Refined Coal Credits and increases production expense by $21,260,000.

Adjustment 9 increases O&M expense by $8,920,000 to normalize maintenance expenses for the Company's six-year maintenance cycle at the Labadie, Sioux, and Rush Island 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 the O&M expense by $2,070,000 related to the previously discussed Meramec Energy Center adjustment.

Adjustment 11 increases O&M expense by $49,057,000 to eliminate the FAC recovery during the test year. Since the Company is re-basing the net base energy costs in its FAC, it is appropriate to eliminate the FAC recovery.

Adjustment 12 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 excluded the cost of a re-fueling outage, as related re-fueling costs are deferred and amortized in accordance with the Commission's Order.[4] 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. The production expenses are increased by $20,557,000 for the outside contractors' maintenance expense and $5,088,000 for incremental overtime expenses. This is a total of $25,645,000. The impact on replacement power and purchase power is part of the fuel and

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[4] File No. EU-2020-0114, Stipulation and Agreement, Filed January 4, 2020 and approved by Order issued February 13, 2020.

purchased power adjustment in Adjustment 5 and 6. The inputs for the PowerSimm model include two-thirds of a Callaway outage.

Adjustment 13 increases O&M expense by $3,664,000 to eliminate amortization of the RES regulatory asset and liability balances established in prior cases. Refer to the discussion below regarding Schedule MJL-D12 (adjustment 11) for the combined effect of over or under-collections of expiring regulatory assets and liabilities in depreciation and amortization, which includes the 2019 RES balance.

Adjustment 14 increases O&M expense by $1,375,000 to re-base expenses related to the RES Tracker, including the Maryland Heights Renewable Energy Center fuel costs.

Adjustment 15 decreases O&M expense by $5,961,000 to eliminate solar rebate costs and amortizations. This amount primarily represents an over-collection of previously tracked costs. Refer to the discussion below regarding Schedule MJL-D12 (adjustment 11) for the combined effect of over or under-collections of expiring regulatory assets and liabilities, which includes the 2019 Solar Rebate balance.

Adjustment 16 increases the O&M expense by $1,594,000 for the amortization of additional over or under-collection of Solar Rebates over a three-year period.

Adjustment 17 decreases O&M expense by $829,000 for a decrease in depreciation that is charged to O&M expense for coal cars, transportation, and heavy duty equipment.

Adjustment 18 increases O&M expense by $1,204,000 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 19 increases O&M expense by $3,458,000 to normalize vegetation management and infrastructure inspection costs to reflect a three-year average. The Company has reduced costs in this area, as referenced by Ameren Missouri witness Warren Wood in his direct testimony. However, on a year-by-year basis, variability still exists. For example, costs during the twelve-months ending December 31, 2021 are expected to be greater than those incurred during the test year. Therefore, normalization via a three-year average remains appropriate.

Adjustment 20 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 December 31, 2020 is deducted from rate base. The interest expense added to the customer accounting expense is $1,063,000.

Adjustment 21 decreases O&M expenses by $69,492,000 to eliminate program costs related to MEEIA, which are included in the MEEIA Rider.

O&M expenses were increased by $189,000 in Adjustment 22 to account for the new on-going cleaning procedures to be implemented subsequent to the COVID-19 pandemic. These costs are not representative of all incremental costs associated with cleaning during the height of the pandemic, but rather the continued incremental costs associated with permanent changes in cleaning protocols subsequent to the pandemic.

Adjustment 23 decreases O&M to a normal the level of bad debt write-offs. Unusually high uncollectible expense was recorded in the test year, as a result of the COVID-19 pandemic. As the COVID-19 pandemic impacted bad debt expense during the test year, it also impacted test year write-off levels making them not representative of normal. The adjustment reflects 2019 write-off levels, as the most recently complete and unaffected calendar year, and decreases operating expense by $6,546,000.

Adjustment 24 increases O&M expenses by $621,000 to annualize membership dues. No Edison Electric Institute dues were included in the test year, therefore the annualized amount associated with this on-going membership was added via this adjustment. Further, two years of Illinois Environmental Regulatory Group dues were included in the test year and this adjustment reflects the inclusion of only dues associated with 2020 (excluding those attributable to lobbying activities). Ameren Missouri belongs to IERG due to its benefits relating to Ameren Missouri's operation of Ameren Missouri generation facilities that are located in Illinois.

The various insurance policies of the Company are renewable at different times during the test year. Adjustment 25 increases the O&M expense by $9,386,000 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 26 increases O&M expenses by $4,824,000 to reflect increases in the other employee benefits expense to annualize the employee benefits expense through September 30, 2021, the proposed true-up period.

O&M expense is increased by $182,000 in Adjustment 27 to annualize the cost of the non-qualified pension plan, which is no longer in the pension tracker, to reflect the annualized calendar year 2021 level of expense.

Adjustment 28 decreases O&M expense by $1,317,000 to rebase the pension and OPEB tracker to reflect the annualized cost levels expected at the true-up date.

Adjustment 29 is an increase to O&M expenses of $7,312,000 to reflect the annualized amortization of the pension and OPEB net regulatory balances, and the estimated net regulatory liability balances at September 30, 2021, the end of the proposed true- up period.

Adjustment 30 increases O&M expense to set the base amount of costs associated with the RESRAM and increases expense by $24,639,000. This rebasing adjustment reflects, in part, the expected annual O&M expenses at the Company's new wind energy centers as of the true-up date.

Adjustment 31 decreases the O&M expenses by $15,000 for the elimination of alcohol purchases during the test year ended December 31, 2020.

O&M expenses are increased in Adjustment 32 by $140,000 to reflect the average rate case expenses incurred by the Company in the last three general rate cases and recovery of these costs over a two-year period. 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 $12,000 shown in Adjustment 35. Ameren Missouri witness Tom Byrne further discusses this adjustment in his direct testimony.

Adjustment 33 increases O&M expenses by $302,000 to annualize the most recent Ameren Missouri electric operations commission assessment.

In Adjustment 34, the Company eliminated $349,000 of O&M expenses for certain Board of Directors meeting expenses and Company chartered flight expenses.

In Adjustment 36, O&M expenses are decreased by $2,462,000 for Bank of America lease costs. This lease is expected to be cancelled prior to the true-up date.

Adjustment 37 decreases O&M expense by $318,000 for reduced software rental costs expected through the true-up date.

Adjustment 38 increases O&M expenses by $137,000 to adjust the allocation factors to the 2021 levels. 2021 levels represent the latest known levels prior to the true-up date.

Adjustment 39 decreases O&M expense to normal levels for expenses directly impacted by the COVID-19 pandemic during the test year. Certain cost increases and cost savings were ordered to be deferred to a regulatory asset for the period ended March 1, 2020 through March 31, 2021 in File No. EU-2021-0027.[5] The Order was received subsequent to the test year and, therefore, not reflected in test year results. This adjustment reduces O&M expense by $5,473,000 for the net, non-normal, deferred amount applicable to the test year.

Adjustment 40 increases O&M expense by $4,601,000 to normalize the Company Owned Life Insurance ("COLI") gains or expenses using a five-year average. COLI contracts contain a net cash surrender value that is invested in debt and equity securities. Variability exists in the returns related to these debt and equity security investments, such that gains or losses may be experienced in any given test year. A five-year normalization period is most appropriate, in this instance, because of the significant volatility experienced in 2018, 2019, and 2020.

Adjustment 41 increases O&M expenses by $14,000 for identified electric costs which were allocated to gas operations in the test year.

[5] File No. EU-2021-0027, Stipulation and Agreement, Filed February 25, 2021 and approved by Order Issued March, 10, 2021.

Adjustment 42 increases O&M expense by $4,676,000 for the Company's proposed waiver of customer-facing convenience charges and inclusion of such charges in this revenue requirement. Customers electing to pay via credit card or at walk-in locations currently pay convenience charges of $1.85 and $1.10 per payment, respectively. Some of Ameren Missouri's peer utilities – Evergy Metro, Inc. d/b/a Evergy Missouri Metro, Evergy Missouri West, Inc. d/b/a Evergy Missouri West and Spire Missouri, Inc. – discontinued the assessment of credit card fees for customers using that payment method. Ameren Missouri wishes to follow suit. The biggest benefit accrues to our residential customers, who are the most likely to use credit cards, and for whom the fees represent a larger percentage of their payments. Waiving these fees takes financial pressure off of these customers. Additionally, credit card payments shift the risk of nonpayment from the utility to the financial institution, which could put downward pressure on bad debt expense. As the MPSC noted in its Spire Missouri, Inc. Order, the utility "would get its money sooner and without the risk of taking a bad check [footnote omitted], and it might see a reduction in its level of bad debt."[6] Ameren Missouri would continue to incur these charges and, via this adjustment, is requesting recovery in this rate case for the fees expected to be incurred. This expectation is based on current contracted fees, 2019 payment levels (2020 payment levels were significantly impacted by the COVID-19 pandemic), and evidence from our third-party service provider suggesting such a change has resulted in a 15% to 30% (midpoint 22.5% utilized in calculating this adjustment) increase in the number of credit card payments made.

[6] *Report and Order* issued February 21, 2018, File Nos. GR-2017-0215 and GR-2017-0216, p. 68

Adjustment 43 increases the O&M expense by $1,000 for electric vehicle incentive costs which were allocated to gas operations in the test year.

Q. What is the impact on total electric O&M expense from the above pro forma adjustments?

A. As shown in Schedule MJL-D11, the total electric O&M expenses are increased from $1,466,015,000 to $1,593,655,000, or a total net increase of $147,640,000 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 December 31, 2020, 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 $65,623,000 to reflect the book depreciation annualized for the plant-in-service depreciable balances at December 31, 2020, and plant additions through the true-up period, based on the depreciation rates approved in File No. ER-2019-0335. Included in this adjustment is the effect of the previously described adjustment related to the upcoming retirement of the Meramec Energy Center.

Depreciation and plant amortization expenses are increased by $96,472,000 in Adjustment 2 to reflect the change in depreciation rates reflected in the depreciation study submitted in this case, which was conducted by Ameren Missouri witness John J. Spanos from Gannett Fleming Valuation and Rate Consultants, LLC. Also included in this adjustment is the effect of the previously described adjustment related to the upcoming retirement of the Meramec Energy Center.

Adjustment 3 increases depreciation and plant amortization by $25,823,000 to eliminate PISA depreciation and amortization deferrals from the test year ended December 31, 2020.

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 $12,236,000 to eliminate depreciation expense on these accounts.

Adjustment 5 increases amortization expense by $4,000 to reflect the annualization of the amortization ordered in File No. ER-2019-0335 for the Callaway Life Extension asset.

Adjustment 6 increases amortization expense by $910,000 to eliminate annual amortization of the construction accounting contra regulatory asset for the Sioux Scrubbers. The Sioux Scrubbers contra regulatory asset is being amortized over the remaining life of the Sioux Energy Center. The contra regulatory asset account is recorded for Generally Accepted Accounting Principles purposes.

Amortization expense is increased by $3,127,000 in Adjustment 7 to eliminate the amortization of the following expiring balances (as named in Commission Order for File No. ER-2019-0335): Expired & Expiring Amortizations – Rate Base ER-2019-0335, Expired & Expiring Amortizations – Non Rate Base ER-2019-0335, Pre-MEEIA Energy

Efficiency, Storm Tracker (2014), Storm Tracker (2016), and Excess Deferred Tax Tracker. Refer to adjustment 11 for the combined effect of over or under-collections of expiring regulatory assets and liabilities for further consideration of these balances.

Adjustment 8 decreases amortization by $615,000 to eliminate the amortization recorded in the test year related to balances that were subsequently combined and netted in File No. ER-2019-0335.

Adjustment 9 increases amortization by $1,813,000 to eliminate MEEIA deferrals and amortizations that are considered under the MEEIA Rider, including MEEIA ordered adjustments.

Adjustment 10 increases amortization expense by $43,000 to annualize the $1,000,000 above-the-line spend for the Low Income Surcharge Pilot Program which was agreed to and approved by the MPSC in File No. ER-2019-0335.

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 case. Any over or under-recovery that will exist at the date new rates are expected to become effective in this rate case will be tracked, combined, and netted for the following balances:

Balance Description	March 1, 2022 Balance (Projected)
Expired & Expiring Amortizations – Rate Base ER-2019-0335 over-recovery	$(1,090,000)
Expired & Expiring Amortizations – Non Rate Base ER-2019-0335 over-recovery	$(3,867,000)

Pre-MEEIA Energy Efficiency under-recovery	$1,314,000
Storm Tracker (2014) over-recovery	$(214,000)
Storm Tracker (2016) over-recovery	$(47,000)
Excess Deferred Tax Tracker over-recovery	$(399,000)
RES Regulatory Liability (2019) over-recovery (1)	$(3,823,000)
Solar Rebate (2019) under-recovery (1)	$148,000
Total over-recovery	$(7,978,000)

(1) Amortization included in O&M during test year. Refer to Schedule MJL-D11.

These tracked, combined, and netted balances will be amortized over a three-year period. Adjustment 11 decreases amortization by $2,660,000 to amortize the combined and netted over- and under-collections associated with expired and expiring regulatory balances.

Adjustment 12 increases amortization by $12,339,000 for the amortization of PISA deferrals over twenty-year periods.

Adjustment 13 decreases amortization by $5,572,000 to eliminate deferrals under the excess deferred taxes tracker and amortized the accumulated balance over a three-year period.

Adjustment 14 decreases amortization by $9,537,000 to eliminate deferrals made under the RESRAM and eliminate amortization associated with amounts recovered through the associated RESRAM rider.

Adjustment 19 increases amortization by $481,000 to recover the Charge Ahead Corridor Program regulatory asset over a seven-year period.

Adjustment 20 decreases amortization by $10,786,000 to reflect refund of the remaining balance associated with the federal income tax rate change (stub period) over a two-year period.

Adjustment 21 increases amortization by $2,459,000 to recover the COVID-19 Accounting Authority Order deferral resulting from File No. EU-2021-0027 over a three-year period.

Q. Are there any other amortization amounts that should be included in the revenue requirement once the related transactions are completed?

A. Yes. After the end of the test year, the Company has incurred, and will continue to incur, equity issuance costs in connection with financing its wind generation investments. The amount of equity issuance costs incurred is dependent, in part, on future events expected to occur by the true-up date. Amortization should increase for equity issuance costs incurred by the true-up date for the Company's investment in the High Prairie and Atchison energy centers. It is appropriate to recover these costs over the remaining useful lives of the facilities.

Q. Should any amount of equity issuance costs be included in the Company's rate base?

A. Yes. Equity issuance costs are costs specifically incurred for the Company's wind investments. These costs should be included in rate base in the same manner as the cost of the turbines and all other plant-in-service costs. All equity issuance costs incurred by the true-up date should be included in the Company's rate base until recovered.

Q. Is the Company requesting accounting authorization to implement this approach?

A. Yes. The Company requests to establish a regulatory asset for equity issuance costs incurred through the true-up date, inclusion of this balance in the Company's rate base, and amortization of these costs over the remaining useful life of the related wind energy centers.

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

A. As reported in Schedule MJL-D13, the total electric pro forma depreciation and amortization expenses are $765,832,000.

Q. Please explain Schedule MJL-D13.

A. Schedule MJL-D13 shows taxes other than income taxes for the twelve months ended December 31, 2020, 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 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 F.I.C.A. taxes by $944,000 to reflect pro forma wage adjustments.

Property taxes of $354,000 applicable to plant held for future use are eliminated in Adjustment 2. This adjustment is required as the investment in plant held for future use is not included in rate base.

Adjustment 3 adjusts taxes other than income taxes to remove Missouri gross receipts taxes of $133,305,000, 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. How much are pro forma taxes other than income taxes for the twelve months ended December 31, 2020 for total electric?

A. As reflected in Schedule MJL-D14, the pro forma total electric taxes other than income taxes are $179,911,000.

Q. What is shown in Schedule MJL-D14?

A. Schedule MJL-D14 shows the derivation of the income tax calculation at the requested 6.995% rate of return for total electric operations reflecting the statutory tax rates. Refer to the direct testimony of Ameren Missouri witness Darryl T. Sagel for the development of the 6.995% 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 $57,680,000 for total electric operations, as shown in Schedule MJL-D15. Deferred income taxes for total electric operations of ($87,775,000) are also shown in Schedule MJL-D15. Net current and deferred income taxes for electric operations are ($30,095,000).

Q. Please explain Schedule MJL-D15.

A. Schedule MJL-D16 shows the total electric rate base of $10,053,174,000, and the total electric revenue requirement of $3,212,523,000 at the requested return of 6.995%.

Q. What does Schedule MJL-D16 reflect?

A. Schedule MJL-D16 compares the total electric revenue requirement of $3,212,523,000 with the total electric pro forma operating revenues under the present rates of $2,913,055,000, including off-system energy sales revenues. It shows that the revenue requirement for the test year is $299,468,000 more than the pro forma operating revenues at present rates. $3,212,523,000 is the amount of revenues used to set the rates filed in this case and is the level of revenues needed to provide Ameren Missouri 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 Ameren Missouri witness Andrew 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 1.149 cents per kilowatt-hour for the summer and 1.036 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 Mr. 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, using inputs provided by Mr. Meyer. There are additional revenues not included in PowerSimm, including the MISO Day 2 revenues, capacity sales, bilateral swaps, financial swaps, 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 $133,564,519 was then divided by the normalized Ameren Missouri summer load at the MISO Node AMMO.UE of 11,627,000,000 kWhs to arrive at a summer value expressed in centers per kWh of 1.149 cents. The winter net base energy cost of $215,033,244 was then divided by the normalized Ameren Missouri winter load at the MISO Node AMMO.UE of 20,762,488,116 kWhs to arrive at a winter value expressed in cents per kWh of 1.036 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.

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 Ameren Missouri?

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 Ameren Missouri'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 Ameren Missouri'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 39.56 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 23.36 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 September 2019 to August 2020. This 12 month period was used instead of the 2020 calendar year due to the limitation of the 150 days of complete data beyond August 2020 relative to the date of filing the case.

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	23.36
Total Revenue Lag	39.56

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 37.09 days, as shown in the following table:

	Revenue Lag (days)	Revenues ($)	Dollar Days ($)
Service Lag	15.21		
Billing Lag	0.99		
Collections Lag	23.36		
Base Revenue (Retail)	39.56	$2,501,995,000	$98,980,522,000
Off-System Sales	18.10	$325,300,000	$5,888,019,000
Total Revenues	37.09	$2,827,295,000	$104,868,541,000

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 24.35 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.[7] 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)

[7] 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 O&M 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) contributions to the Company’s pension fund; d) OPEB costs; and e) the Company's 401-K plan. Taken together, these programs had a dollar-weighted lead time of 18.37 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 11.66 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 O&M 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 O&M 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 is calculated as a percent of billings less a 2 percent timely payment allowance. Estimated payments are made weekly with the tax return and remaining balance due by the 20th of the month following except for the last month at the

end of the quarter for which the tax return and payment are due on the last day of the month following. 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 annually to the federal government 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 Ameren Missouri 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 test year. 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 test year?

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 were 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 252.88 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 of four existing trackers: the pension and OPEB expense tracker, the RES tracker, the FIN48 tracker, and the excess deferred tax amortization tracker. Further, the Company requests that amounts related to the Meramec Energy Center be tracked and recovered over a five-year period beginning when rates become effective in this rate case. 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 6.995% return on rate base is more than the pro forma operating revenues at the present rates by $299,468,000. Consequently, rates should be designed to increase revenues by $299,468,000, 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.

Schedules MJL-D1 through

MJL-D18 filed as an

attachment

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-2021-0240

AFFIDAVIT OF MITCHELL LANSFORD

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

Mitchell Lansford, being first duly sworn on his oath, states:

My name is Mitchell Lansford, and on his oath declare that he is of sound mind and lawful age; that he has 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 Lansford
Mitchell Lansford

Sworn to me this 31st day of March, 2021.