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Ameren – Exhibit 45  
Mitchell Lansford  
Direct Testimony  
File No. ER-2022-0337

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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**

## TABLE OF CONTENTS

I.	INTRODUCTION .....	1
II.	PURPOSE OF TESTIMONY .....	2
III.	REVENUE REQUIREMENT .....	6
IV.	DETERMINATION OF NET BASE ENERGY COSTS.....	39
V.	CASH WORKING CAPITAL ANALYSIS.....	41
VI.	CONCLUSION.....	55

**DIRECT TESTIMONY**  
**OF**  
**MITCHELL J. LANSFORD**  
**FILE NO. ER-2022-0337**

**I. INTRODUCTION**

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**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

1 environment. From 2019 to present, I have been working for Ameren Missouri in multiple  
2 regulatory accounting roles, including my current role as Director, Regulatory Accounting  
3 effective in April 2020.

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

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

9 **II. PURPOSE OF TESTIMONY**

10 **Q. What is the purpose of your direct testimony?**

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

1           **Q.     Are you sponsoring any schedules?**

2           A.     Yes. I am sponsoring Schedules MJL-D1 through MJL-D18.

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

4           A.     Schedules MJL-D1 through MJL-D18 develop the various elements of the  
5 revenue requirement to be considered in arriving at the proper level of rates for the  
6 Company's electric service based on the test year of the twelve months ended March 31,  
7 2022, with pro forma adjustments and updates for known and measurable changes to be  
8 trued-up through December 31, 2022. Schedule MJL-D17 reflects the calculation of net  
9 base energy costs ("NBEC") and the seasonal values for Factor BF in Rider FAC. Schedule  
10 MJL-D18 reflects the results of the cash working capital lead-lag study prepared as of the  
11 twelve months ended December 31, 2020.

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

14           A.     Each schedule provides the following information:

- 15                   • Schedule MJL-D1 – Original Cost of Electric Plant by functional  
16                   classification at March 31, 2022, per book and pro forma.
- 17                   • Schedule MJL-D2 – Electric Plant Reserves for Depreciation and  
18                   Amortization by functional classification at March 31, 2022, per book  
19                   and pro forma.
- 20                   • Schedule MJL-D3 – Average Fuel Inventories and Average Materials  
21                   and Supplies Inventories at March 31, 2022, per book and pro forma  
22                   applicable to electric operations.

- 1                   • Schedule MJL-D4 – Average Pre-payments at March 31, 2022, per book  
2                   and pro forma applicable to electric operations.
- 3                   • Schedule MJL-D5 – Total Electric Cash Working Capital (per the  
4                   Company’s lead/lag study) for the twelve months ended March 31,  
5                   2022, applicable to electric operations.
- 6                   • Schedule MJL-D6 – Interest Expense Cash Requirement, Federal  
7                   Income Tax Cash Requirement, State Income Tax Cash Requirement,  
8                   and City of St. Louis Earnings Tax Cash Requirement applicable to  
9                   electric operations for the twelve months ended March 31, 2022.
- 10                  • Schedule MJL-D7 – Average Electric Customer Advances for  
11                  Construction and Average Electric Customer Deposit reductions to rate  
12                  base at March 31, 2022.
- 13                  • Schedule MJL-D8 – Regulatory Asset and Liability balances included  
14                  in rate base at March 31, 2022, per book and pro forma.
- 15                  • Schedule MJL-D9 – Total Electric Accumulated Deferred Income  
16                  Taxes at March 31, 2022, per book and pro forma.
- 17                  • Schedule MJL-D10 – Total Electric Operating Revenues for the twelve  
18                  months ended March 31, 2022, per book and pro forma.
- 19                  • Schedule MJL-D11 – Total Electric Operations and Maintenance  
20                  Expenses, by functional classification, for the twelve months ended  
21                  March 31, 2022, updated for certain known items, per book and pro  
22                  forma. A description of each of the pro forma adjustment is included.

- 1                   • Schedule MJL-D12 – Depreciation and Amortization Expenses  
2                   applicable to electric operations, by functional classification, for the  
3                   twelve months ended March 31, 2022, per book and pro forma. A  
4                   description of each pro forma adjustment is included.
- 5                   • Schedule MJL-D13 – Taxes Other Than Income Taxes, for the twelve  
6                   months ended March 31, 2022, per book and pro forma for the electric  
7                   operations of the Company. A description of each pro forma adjustment  
8                   is included.
- 9                   • Schedule MJL-D14 – Income Tax Calculation at the proposed rate of  
10                  return and statutory tax rates for the total electric operations of the  
11                  Company.
- 12                  • Schedule MJL-D15 – The pro forma Electric Net Original Cost Rate  
13                  Base at March 31, 2022, and Electric Revenue Requirement including  
14                  the pro forma adjustments.
- 15                  • Schedule MJL-D16 – The annual revenue increase required at a 7.186%  
16                  return on Net Original Cost Electric Rate Base, including pro forma  
17                  adjustments.
- 18                  • Schedule MJL-D17 – Calculation of NBEC and seasonal values of  
19                  Factor BF in Rider FAC.
- 20                  • Schedule MJL-D18 – Cash Working Capital Factors.



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**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

1 and other post-employment benefits ("OPEB"), tracked regulatory asset/liability balances,  
2 customer growth, net energy costs (as defined in Rider FAC), Midcontinent Independent  
3 System Operator, Inc. ("MISO") transmission revenues and expenses, payroll, employment  
4 levels, other employee benefits, Renewable Energy Standard ("RES") costs, bad debt  
5 expense, Callaway re-fueling expenses, steam plant maintenance, storm costs, software  
6 maintenance, cybersecurity expenses, Renewable Energy Standard Rate Adjustment  
7 Mechanism ("RESRAM") costs, insurance expenses, Pay as You Save ("PAYS") amounts,  
8 the Missouri Public Service Commission ("MPSC") assessment, lease expense, capital  
9 structure, capital costs, depreciation expense, income taxes, non-income taxes and various  
10 amortization amounts (such as the pension & OPEB tracker amortization). The Company  
11 will also true-up coal prices, MISO Schedule 26-A rates, and any wage increases that  
12 become effective on or before January 1, 2023. Finally, the Company proposes that other  
13 significant items that may arise through the true-up date, both increases and decreases,  
14 should be trued-up through December 31, 2022.

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

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

1           **Q.     Please explain Schedule MJL-D1.**

2           A.     Schedule MJL-D1 shows the recorded original cost of electric plant by  
3 functional classification at March 31, 2021, along with the estimated plant additions and  
4 other adjustments through December 31, 2022, which is the end of the Company's proposed  
5 true-up period. The Company's plant accounts are recorded on the basis of original cost as  
6 defined by the Uniform System of Accounts and prescribed by the MPSC.

7           **Q.     Please explain the elimination of the plant balances related to the**  
8 **Financial Accounting Standard ("FAS") 143 *Asset Retirement Obligations* ("ARO"),**  
9 **and the Accounting Standards Codification ("ASC") 842 *Leases* shown as the first**  
10 **adjustment on Schedule MJL-D1.**

11          A.     FAS 143 is an accounting requirement to reflect the fact that the Company  
12 has an asset and corresponding legal obligation to remove certain facilities in the future.  
13 ASC 842 is an accounting requirement that leases are recorded on the balance sheet in the  
14 form of an asset, and an equivalent offsetting liability. Adjustment 1 to plant, in the amount  
15 of (\$298,629,000) eliminates both the ARO and lease investments for ratemaking purposes.

16          **Q.     Why is the Company including plant additions through December 31,**  
17 **2022?**

18          A.     Consistent with its plans submitted to the MPSC, the Company continues  
19 to invest in infrastructure upgrades and replacements throughout its service territory under  
20 its Smart Energy Plan. Company witness Warren Wood highlights some of important  
21 projects under the Smart Energy Plan in his direct testimony, and Company witness Ryan  
22 Arnold addresses specifically the Company's ongoing efforts to ensure the long-term  
23 reliability of its energy delivery system. In order to provide the Company an opportunity

1 to earn a fair and reasonable return on its total investment, it is necessary for the cost of  
2 service to reflect, as closely as possible, the level of the Company's investment at the time  
3 new rates will become effective. Adjustment 2 adds the estimated plant-in-service  
4 additions, offset by retirements, of \$1,416,558,000 from March 31, 2022, through  
5 December 31, 2022, which is the end of the proposed true-up period.

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

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

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

17 A. General and Intangible Plant assets, such as general office buildings, the  
18 central warehouse, the central garage, software, computers, and office equipment are used  
19 in both the electric and gas operations. For convenience, such investments are presented as  
20 electric plant in our accounting records. Adjustment 4 eliminates the portion of the multi-  
21 use General Plant and Intangible Plant allocated to the Company's gas operations of  
22 \$17,454,000 and \$25,204,000, respectively.

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<sup>1</sup> File No. ER-2021-0240, Unanimous Stipulation and Agreement, p. 4, para. 9, filed November 24, 2021.

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

3           A.     In past Ameren Missouri rate reviews, a portion of the Company's incentive  
4 compensation paid has either been disallowed or was not requested for recovery by the  
5 Company. Within the accounting records of the Company, a portion of the compensation  
6 has been capitalized and added to plant-in-service. Adjustment 5 reduces the plant-in-  
7 service balance by \$57,165,000 for the accumulated amount of any previously disallowed  
8 and/or not requested capitalized incentive compensation.

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

11          A.     As shown in Schedule MJL-D1, the total electric plant-in-service is  
12 \$22,883,458,000.

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

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

18                 Adjustment 2 increases the depreciation reserve by \$549,802,000 to reflect  
19 depreciation through the true-up date on plant-in-service investments existing at March 31,  
20 2022.

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

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

5            Adjustment 5 eliminates the accumulated depreciation and amortization reserve of  
6 \$5,187,000 for the multi-use General Plant applicable to gas operations. Adjustment 5 also  
7 eliminates \$11,138,000 of the accumulated amortization related to Intangible Plant  
8 applicable to gas operations. This adjustment corresponds to Adjustment 4 made to plant-  
9 in-service on Schedule MJL-D1.

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

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

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

17           A.     Schedule MJL-D3 shows the average investment in fuel inventories,  
18 materials and supplies at March 31, 2022. Fuel consists of nuclear fuel, coal, minor  
19 amounts of oil and stored natural gas used for electric generation, emissions allowances,  
20 and renewable energy credits ("RECs"). The nuclear fuel balances include the nuclear fuel  
21 in the reactor as well as the nuclear fuel on site at the Callaway Energy Center. General  
22 materials and supplies include such items as poles, cross arms, wire, cable, line hardware,  
23 and general supplies. A thirteen-month average is used for all these items, except nuclear

1 fuel. An eighteen-month average is used for the nuclear fuel since the Callaway Energy  
2 Center is re-fueled every eighteen months.

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

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

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

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

22 A. Yes. Upon retirement and closure of the Company's Meramec Energy  
23 Center, a materials and supplies inventory write-off is expected for inventoried items

1 necessary to maintain reliable operations but no longer necessary after retirement.<sup>2</sup> The  
2 Company requests authority to defer these write-offs and amortize and recover these costs  
3 over a two-year period beginning with the implementation of new customer rates in this  
4 rate review.

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

7 A. The pro forma materials and supplies applicable to total electric operations,  
8 as shown in Schedule MJL-D3, is \$567,950,000.

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

10 A. Certain costs for items such as rent, insurance, service agreements, medical  
11 and dental voluntary employee beneficiary association ("VEBA") contributions, digital  
12 subscriptions, and others are paid in advance. After elimination of amounts applicable to  
13 gas operations, the thirteen-month average balance of total electric pre-payments at March  
14 31, 2022, is \$16,327,000.

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

16 A. Schedule MJL-D5 shows the calculation of the electric cash working capital  
17 requirement as a negative net cash requirement of (\$15,778,000), which is based on a  
18 lead/lag study for the twelve months ended December 31, 2020, and including pro forma  
19 adjustments to operating expenses. I will explain the details of the lead/lag study later in  
20 this testimony.

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<sup>2</sup> Net of any salvage proceeds.



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

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

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

9           A.     Reflecting the payment lead times for each of these items compared to the  
10 revenue lag results in negative cash requirements of (\$32,161,000) for interest expense,  
11 (\$189,000) for federal income taxes, (\$64,000) for state income taxes, and (\$89,000) for  
12 city earnings tax. The cash requirements for Indiana income taxes and Iowa income taxes  
13 are zero because these taxes were not incurred during the twelve months ended March 31,  
14 2022.

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

16          A.     The thirteen-month average balances at March 31, 2022, for electric  
17 customer advances for construction and electric customer deposits are shown in Schedule  
18 MJL-D7. These items represent cash provided by customers that can be used by the  
19 Company until they are refunded. Therefore, the average balances for the customer  
20 advances for construction and customer deposits are reductions to the Company's rate base.

21                 Customer advances for construction are cash advances made by customers that are  
22 subject to refund to the customers in whole or in part. These advances provide the Company  
23 cash that offsets the cost of the construction until they are refunded. The thirteen-month

1 average balance of electric customer advances for construction was \$546,000 at March 31,  
2 2022.

3 Customer deposits are cash deposits made by customers which are subject to refund  
4 to the customer if the customer develops a good payment record. The Company pays  
5 interest on the deposits, which is shown as a customer accounting expense in Schedule  
6 MJL-D11. The thirteen-month average balance of electric customer deposits was  
7 \$18,816,000 at March 31, 2022.

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

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

14 The pension and OPEB regulatory liability balances are shown for the period ended  
15 March 31, 2022, and further amortized through the true-up date. In File No. ER-2021-0240,  
16 the pension and OPEB tracker expenses accumulated from January 1, 2020, through  
17 September 30, 2021, were set to amortize over a five-year period scheduled to end in  
18 February 2027. Prior tracked amounts were established in prior rate reviews and set to  
19 amortize over three- or five-year periods. Amortization calculations in prior rate reviews  
20 were based on expected customer rate implementations on the operation of law dates in  
21 those cases. However, some prior rate reviews have resulted in earlier rate implementations  
22 and further resulted in amortization amounts that will not result in the full amortization of  
23 remaining balances over the specified term. As a result, the Company proposes that all

1 pension and OPEB deferrals established in prior rate reviews, and not yet fully recovered  
2 or refunded, are amortized over two years beginning with the effective date of new  
3 customer rates in this rate review. Doing so will accelerate refunds to customers, eliminate  
4 historical tracking complexities, and correct amortization calculations based on  
5 implementation dates that differed from the operation of law date in past rate reviews.  
6 Refund of this net regulatory liability over two years is appropriate given the recent  
7 Company history of filing rate reviews approximately every two years. For clarity,  
8 deferrals established in this rate review should continue to be amortized over five years.  
9 \$39,679,776 is the expected net regulatory liability and rate base reduction at December  
10 31, 2022, reflecting the details of this proposal.

11           Schedule MJL-D8 also includes the PISA regulatory asset balance included in rate  
12 base. PISA is the name commonly given to the deferrals of 85% of the depreciation expense  
13 and return on "qualifying electric plant" as required by Section 393.1400, RSMo., under  
14 legislation adopted by the Missouri General Assembly in 2018 and amended in 2022. In  
15 File No. ER-2019-0335, a regulatory asset was established for PISA accumulations from  
16 September 1, 2018, to December 31, 2019. This regulatory asset is being amortized over  
17 the 20-year period ending May 31, 2040. In File No. ER-2021-0240, a regulatory asset was  
18 established for PISA accumulations from January 1, 2020, to September 30, 2021. This  
19 regulatory asset is being amortized over the 20-year period ending March 31, 2042. A third  
20 regulatory asset has been established for PISA accumulations from October 1, 2021, to  
21 December 31, 2022, and will be amortized over 20 years. The total PISA regulatory asset  
22 balance of \$394,572,000 reflects the deferral made, and estimated, under PISA on or after  
23 September 1, 2018, through December 31, 2022, net of amortization. The statute also

1 provides that in each general rate proceeding, the balance of the PISA regulatory asset as  
2 of the rate base cutoff date (i.e., December 31, 2022) shall be included in the participating  
3 utility's rate base.

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

9 The Meramec Retirement asset was established in the Unanimous Stipulation and  
10 Agreement from File No. ER-2021-0240.<sup>3</sup> The amount represents an agreed upon amount  
11 of non-labor operating costs associated with the normal operations, not including post-  
12 closure costs, of the Meramec Energy Center through its retirement. These costs are  
13 recovered over five years, instead of less than one year, as a way to keep customer rates  
14 affordable for the Company's customers. The overwhelming majority of the costs giving  
15 rise to this deferral are those that should be included in rate base (e.g., depreciation).  
16 Accordingly, the remaining unrecovered Meramec Retirement asset is included in rate  
17 base.

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

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<sup>3</sup> *Id.*

<sup>4</sup> File No. ER-2016-0179, Unanimous Stipulation and Agreement, filed February 23, 2017.

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

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

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

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

1 Accumulated deferred income taxes are the net result of normalizing the tax benefits  
2 resulting from timing differences between the periods in which transactions affect taxable  
3 income and the period in which such transactions affect the determination of pre-tax  
4 income.

5 Currently, the Company has deferred income taxes in Federal Energy Regulatory  
6 Commission ("FERC") Accounts 190, 281, 282, and 283. As shown in Schedule MJL-D9,  
7 the total electric pro forma accumulated deferred income tax balance is a net liability  
8 balance of \$2,968,208,000. Net deferred income tax liabilities are a deduction from rate  
9 base.

10 **Q. What is the Company's pro forma net original cost electric rate base at**  
11 **March 31, 2022?**

12 A. The Company's total electric rate base as shown in Schedule MJL-D15 is  
13 \$11,605,779,000.

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

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

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

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

21 Adjustment 1 eliminates revenue add-on taxes of \$143,699,000, as they are directly  
22 passed through to customers by the Company; Adjustment 2 eliminates the Missouri  
23 Energy Efficiency Investment Act ("MEEIA") revenues of \$135,558,000, as they are

1 collected through the MEEIA Rider rather than through base rates. Adjustment 3 eliminates  
2 FAC revenues of \$88,220,000, as they are collected through the FAC Rider rather than  
3 base rates. Adjustment 4 eliminates the effect of unbilled revenues and decreases revenues  
4 by \$22,430,000. After the unbilled revenue adjustment, book revenues are reflected on a  
5 bill cycle basis. Because new retail rates (resulting from File No. ER-2021-0240) were  
6 effective February 28, 2022, Adjustment 5 increases revenues by \$214,415,000 to  
7 annualize the effect of those new rates to the full test year. Adjustment 6 removes \$676,000  
8 of revenues as a result of the economic development incentive adjustment ("EDI"), an  
9 adjustment made to account for base rate revenues that were not collected due to discounts  
10 on base rates granted under the Company's economic development incentive provisions  
11 under Rider No. 86 approved with Section 393.1640 RSMo. Adjustment 7 increases  
12 revenues by \$221,000 to reflect revenues expected to be received as part of the Company's  
13 Community Solar Program. Adjustment 8 increases revenues by \$5,893,000 to reflect  
14 estimated customer growth through December 31, 2022. Adjustment 9 reduced revenues  
15 by \$1,531,000 to remove revenues recovered under the RESRAM. To annualize the impact  
16 of energy efficiency efforts and customer-owned solar installations, most of which were  
17 incentivized through Company rebate programs, revenues are being reduced by  
18 \$16,225,000 in Adjustment 10. Since the Company uses cycle and window billing,  
19 revenues are increased by \$8,567,000 to reflect the twelve-month billing year as a twelve-  
20 month, 365-day, calendar year in Adjustment 11. Adjustment 12 increases revenues by  
21 \$12,594,000 to synchronize the book revenues with the Company's billing unit rate  
22 analysis. Revenues were decreased in Adjustment 13 by \$29,185,000 to reflect normal

1 weather. Revenue adjustments 5, 6, 7, 8, 10, 11, 12, and 13 are further discussed by  
2 Company witness Nicholas Bowden in his direct testimony.

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

5 The "other electric revenues" in Schedule MJL-D10 were increased by \$348,000  
6 in Adjustment 15 for estimated transmission revenues through December 31, 2022, the  
7 proposed true-up date. IRS Section 45 Refined Coal Credits expired and, therefore,  
8 revenues are reduced by \$311,000 to remove this expiring source of revenue in Adjustment  
9 16. Adjustment 17 decreases other revenue by \$2,151,000 to annualize late fee revenues to  
10 levels based on the agreed upon late payment fee rate established in File No. ER-2021-  
11 0240. Adjustment 18 decreases other revenue by \$87,950,000 for non-recurring insurance  
12 recoveries related to the unplanned outage at the Callaway Energy Center that began in  
13 December 2020. Adjustment 19 increases revenue by \$196,000 to reflect expected  
14 additional intercompany facility rental revenue. In Adjustment 20, the Company is  
15 decreasing revenues by \$922,000 because certain software assets will be fully amortized  
16 prior to true-up date and therefore will no longer be a source of rental revenue. In  
17 Adjustment 21, revenues were decreased by \$375,000 to reflect the cancelation of the Bank  
18 of America building lease. Adjustment 22 increases revenue by \$19,000 for annual  
19 revenues expected at the true-up date under the PAYS program. Adjustment 23 eliminates  
20 revenue add-on taxes of \$1,027,000 applicable to other revenues, as they are directly  
21 passed through to customers from other revenues by the Company.

22



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

3           A.    Yes, Adjustment 25 in Schedule MJL-D10 increases the actual off-system  
4 sales revenues from energy by \$56,291,000 to reflect a normal level of off-system sales  
5 calculated using the current normalized market price for energy and the annualized power  
6 and ancillary services market revenues from MISO, as discussed in the direct testimony of  
7 Company witness Meyer. Adjustment 26 increases sales of capacity by \$211,108,000, to  
8 reflect a normal level of capacity sales, as is also addressed in Company witness Meyer's  
9 direct testimony. The production cost model ("PowerSIMM"), explained in the direct  
10 testimony of Company witness Mark Peters, was used to develop the normal off-system  
11 sales volumes and revenues from energy sales.

12           **Q.    What are the pro forma electric operating revenues for the twelve**  
13 **months ended March 31, 2022?**

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

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

17           A.    Total electric O&M for the twelve months ended March 31, 2022 (per books  
18 by functional classification), the pro forma electric operations and maintenance expenses  
19 by functional classification, and a listing of the pro forma adjustments are shown in  
20 Schedule MJL-D11.

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

3           A. A summary of the pro forma adjustments to O&M appears in Schedule  
4 MJL-11. Adjustment 1 reflects the increased labor expenses related to union and  
5 management wage increases at January 1, 2022, and January 1, 2023. A 2.5% wage  
6 increase for union employees was effective January 1, 2022, per the labor contracts. A  
7 2.25% wage increase for management employees was effective January 1, 2022. In  
8 addition, the Company expects union and management employee to receive average wage  
9 increases of 3.75% effective January 1, 2023. The annualized increase in the total electric  
10 operating labor expense resulting from wage increases is \$17,728,000. These wage  
11 increases reflect known and measurable changes that will occur subsequent to the test year.  
12 Incentive compensation was excluded from the calculation of the wage increases, as wage  
13 increases only apply to base wages.

14           Adjustment 2 reduces O&M by \$1,969,000 to eliminate the incentive  
15 compensation that is based on the achievement of earnings-per-share goals of the Company  
16 and, for remaining incentive compensation not eliminated, adjust to payments made under  
17 the plans in 2022.

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

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

6 Adjustment 4 reflects a decrease in O&M expense of \$11,886,000 for fuel expense  
7 and was calculated by Company witness Peters using the PowerSIMM production cost  
8 model. His direct testimony details the inputs and assumptions used in the PowerSIMM  
9 production cost model.

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

13 The increases and decreases in the O&M expenses contained in Adjustment 4 and  
14 5 were calculated by Company witness Peters using the PowerSIMM production cost  
15 model. His direct testimony details the inputs and assumptions used in the PowerSIMM  
16 production cost model. The purchased power expenses also include the power market and  
17 ancillary services changes from MISO.

18 Adjustment 6 reduces O&M expense by \$125,000 to reflect an adjustment ordered  
19 by the MPSC in its Report and Order in File No. EO-2011-0128, issued April 19, 2012, as  
20 modified by the Commission's Order Modifying Report and Order issued December 22,  
21 2014. The referenced orders require that the Company make certain adjustments for  
22 ratemaking purposes for transmission charges from MISO for regionally allocated  
23 transmission facilities constructed by an Ameren Missouri affiliate in the service territory

1 of Ameren Missouri. Ameren Missouri has received MISO transmission charges arising  
2 from one such project, the Mark Twain Transmission Project, and thus has adjusted its  
3 revenue requirement in this case for charges received on the project through March 31,  
4 2022.

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

8 Adjustment 8 removes reductions in O&M expenses related to the previously  
9 discussed IRS Section 45 Refined Coal Credits and increases production expense by  
10 \$15,105,000.

11 Adjustment 9 increases O&M expense by \$1,496,000 to normalize non-labor  
12 maintenance expenses over the Company's planned six-year maintenance cycle at the  
13 Labadie and Sioux Energy Centers. Given the six-year maintenance cycle, a specific test  
14 year is not representative of the normal maintenance expense levels incurred. This  
15 adjustment reflects an adjustment of maintenance expenses to the six-year average of  
16 historical costs, which is consistent with the maintenance cycle at these plants.

17 Adjustment 10 reduces O&M expenses by \$2,539,000 to reflect reduced  
18 operations of the Rush Island Energy Center expected to result from New Source Review  
19 litigation.

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

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

4           Adjustment 13 is an increase to O&M expense to include two-thirds of the average  
5 of the last three Callaway Nuclear Energy Center re-fueling expenses. This adjustment is  
6 required because the outage cycle at the Callaway Nuclear Energy Center occurs every 18  
7 months and the test year partially excluded the cost of a re-fueling outage, as related re-  
8 fueling costs are deferred and amortized in accordance with the Commission's Order in  
9 File No. EU-2020-0114. Therefore, in order to reflect an annual amount of operations and  
10 maintenance expenses, it is necessary to include two-thirds (12-month annual period for  
11 setting rates as compared to the 18-month outage cycle) of Callaway Energy Center re-  
12 fueling expenses. Further variability exists in the level of expenses incurred during a re-  
13 fueling outage. This adjustment also reflects normalization of costs by averaging the costs  
14 of the past three Callaway re-fueling outages. Production expenses must be increased by  
15 \$22,715,000 for non-labor maintenance expense and \$5,262,000 for incremental overtime  
16 expenses. Adjustment 13 results in a total increase of \$27,977,0000.

17           Adjustment 14 is a decrease in O&M expense of \$27,887,000 to eliminate the  
18 Callaway Energy Center refueling amortization recorded in accordance with the  
19 Commission's order in File No. EU-2020-0114 from the test year. The net impact of  
20 adjustments 13 and 14 is an increase in O&M expense of \$90,000.

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

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

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

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

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

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

14          Adjustment 21 decreases O&M expense by \$5,330,000 to normalize storm costs  
15 to reflect a five-year average. Variability exists in the level of storm costs experienced in  
16 any given test year. This normalization adjustment is consistent with past practice.

17          Adjustment 22 is an increase to O&M expenses to reflect interest expense at 4.25%  
18 on the average customer deposit balance. The average customer deposit balance at March  
19 31, 2022, is deducted from rate base. The interest expense added to the customer  
20 accounting expense is \$800,000.

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

1           Adjustment 24 increases O&M expense by \$163,000 for the annual amortization  
2 of the PAYS regulatory assets expected at the true-up date. This adjustment includes  
3 annualization of the amortization authorized in File No. ER-2021-0240 and amortization  
4 of incremental deferrals expected through the true-up date. The amortization period relating  
5 to the incremental deferrals will be calculated based on the remaining weighted useful life  
6 of measures installed under the program at the proposed true-up date.

7           Adjustment 25 increases O&M by \$3,572,000 to annualize bad debt expense to  
8 the level of bad debt net write-offs from the test year. Test year bad debt expense was  
9 significantly impacted by incremental accruals recorded in 2020 that did not result in write-  
10 offs, at least in part as a result of payment assistance programs offered, administered, or  
11 enabled by the Company in response to the Covid-19 pandemic.

12           The various insurance policies of the Company are renewable at different times  
13 during a year. Adjustment 26 increases the O&M expense by \$3,018,000 to annualize the  
14 premiums of the various insurance policies in effect, or expected to be in effect, at the time  
15 new rates are expected to be implemented in this case.

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

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

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

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

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

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

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

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

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

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

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



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

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

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

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

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

17           Adjustment 44 increases O&M expense by \$3,849,000 for customer convenience  
18 charges (e.g. credit card fees) that are included in the Company's revenue requirement in  
19 accordance with File No. ER-2021-0240. This change was implemented on February 28,  
20 2022, and, therefore, this adjustment reflects an annualization of the expense necessary for  
21 a full 12 months.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

18                 Depreciation and plant amortization expenses are increased by \$24,056,0000 in  
19 Adjustment 2 to reflect the change in depreciation rates reflected in the depreciation study  
20 submitted in this case, which was conducted by Company witness John J. Spanos from  
21 Gannett Fleming Valuation and Rate Consultants, LLC.

1           Adjustment 3 increases depreciation and plant amortization by \$93,964,000 to  
2 eliminate PISA depreciation and amortization deferrals from the test year ended March 31,  
3 2022.

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

8           Adjustment 5 increases amortization expense by \$1,341,000 to eliminate annual  
9 amortization of the construction accounting contra regulatory asset for the Sioux  
10 Scrubbers. The contra regulatory asset account is recorded for Generally Accepted  
11 Accounting Principles ("GAAP") purposes and has no impact on ratemaking in the State  
12 of Missouri. This adjustment also includes an increase in amortization of the regulatory  
13 asset for the construction accounting of the Sioux Scrubbers to reflect a retirement date of  
14 2030.

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

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

21           Adjustment 8 increases amortization expense by \$1,926,000 for the amortization  
22 and recovery of costs for a study of customer affordability opportunities. This study was  
23 conducted in support of the Company's efforts toward reaching its customer affordability

1 goals. Company witness Wood discuss the Company's affordability efforts in his direct  
2 testimony. It is appropriate to amortize total non-labor costs associated with this study over  
3 a period of 5 years to better align recovery of these costs with the timing of the benefits  
4 supported by the study.

5 Adjustment 9 increases amortization expense by \$917,000 to annualize the  
6 \$2,000,000 above-the-line spend for the Keeping Current and Keeping Cool Program. This  
7 adjustment reflects a continuation of the \$4,000,000 funding level agreed to and approved  
8 in File No. ER-2021-0240, split evenly between customers and the Company.

9 As previously referenced, the Company has combined and netted regulatory assets  
10 and liabilities expected to expire prior to, or soon after, the date new rates are expected to  
11 become effective in this rate review. Any over or under-recovery that will exist at the date  
12 new rates are expected to become effective in this rate review will be tracked, combined,  
13 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)

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

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

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

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

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

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

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

21 Adjustment 17 increases amortization by \$1,782,000 to reflect amortization of the  
22 equity costs associated with the issuance of equity for the funding of the High Prairie and

1 Atchison renewable energy centers over a period of 5 years beginning with new rates  
2 effective February 28, 2022, consistent with Staff's proposal in File No. ER-2021-0240.<sup>5</sup>

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

5 Adjustment 19 increases amortization expense by \$229,000 to annualize the  
6 \$250,000 above-the-line spend for the Critical Needs Low Income program. This  
7 adjustment reflects the establishment of the \$500,000 funding level agreed to and approved  
8 in File No. ER-2021-0240, split evenly between customers and the Company.

9 Adjustment 20 increases amortization expense by \$229,000 to annualize the  
10 \$250,000 above-the-line spend for the Rehousing Pilot Low Income program. This  
11 adjustment reflects the establishment of the \$500,000 funding level agreed to and approved  
12 in File No. ER-2021-0240, split evenly between customers and the Company.

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

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

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

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

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<sup>5</sup> File No. ER-2021-0240, Staff Direct Cost of Service Report, p.180.

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

3           A. The following pro forma adjustments detailed in Schedule MJL-D13 are  
4 required to arrive at the total electric pro forma taxes other than income taxes. Adjustment  
5 1 increases Federal Insurance Contributions Act ("FICA") taxes by \$997,000 to reflect pro  
6 forma wage adjustments.

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

9           Property taxes of \$302,000 applicable to plant held for future use are eliminated  
10 in Adjustment 3. This adjustment is required as the investment in plant held for future use  
11 is not included in rate base.

12           Adjustment 4 adjusts taxes other than income taxes to remove Missouri gross  
13 receipts taxes of \$145,597,000, as they are add-on taxes that are directly passed through to  
14 customers. The pro forma book revenues also reflect the removal of the add-on revenue  
15 taxes.

16           **Q. Is the Company implementing the Property Tax Tracker newly**  
17 **established by Section 393.1275, RSMo.?**

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



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

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

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

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

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

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

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

16           A. Schedule MJL-D14 shows the derivation of the income tax calculation at  
17 the requested 7.186% rate of return for total electric operations reflecting the statutory tax  
18 rates. Refer to the direct testimony of Company witness Darryl T. Sagel for the  
19 development of the 7.186% rate of return.

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

22           A. Total current federal, state, and city earnings income taxes using the  
23 statutory tax rates at the requested rate of return are \$94,292,000 for total electric

1 operations, as shown in Schedule MJL-D14. Deferred income taxes for total electric  
2 operations of (\$88,881,000) are also shown in Schedule MJL-D14. Net current and  
3 deferred income taxes for electric operations are \$5,411,000.

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

5 A. Schedule MJL-D15 shows the total electric rate base of \$11,605,779,000  
6 and the total electric revenue requirement of \$3,627,692,000 at the requested return of  
7 7.186%.

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

9 A. Schedule MJL-D16 compares the total electric revenue requirement of  
10 \$3,627,692,000 with the total electric pro forma operating revenues under the present rates  
11 of \$3,312,063,000, including off-system energy sales revenues. It shows that the revenue  
12 requirement for the test year is \$315,629,000 more than the pro forma operating revenues  
13 at present rates. \$3,627,692,000 is the amount of revenues used to set the rates filed in this  
14 case and is the level of revenues needed to provide the Company an opportunity to collect  
15 and recover its cost of service, including an opportunity to recover its cost of capital.

16 **IV. DETERMINATION OF NET BASE ENERGY COSTS**

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

19 A. Yes. I calculated the net base energy costs and the seasonal values for Factor  
20 BF in Rider FAC for both the summer and winter, which are 1.448 cents per kilowatt-hour  
21 for the summer and 1.312 cents per kilowatt-hour for the winter. Schedule MJL-D17 shows  
22 the calculation of total net base energy costs, and the calculation of the Factor BF values  
23 for the summer and winter periods. The net base energy costs calculation starts with the

1 fuel and purchased power costs determined by PowerSIMM, as discussed in Company  
2 witness Peters' direct testimony. There are other costs for fuel and purchased power that  
3 are not modeled by PowerSIMM, including net fly ash revenues and expenses, fixed gas  
4 supply costs, fuel additives, MISO Day 2 expenses, capacity expenses, replacement power  
5 insurance costs, Account 565 transmission expenses, the cost of purchasing ancillary  
6 services, and the cost of purchased power to serve common boundary customers. This total  
7 cost of fuel and purchased power is then offset or reduced by off-system energy sales  
8 revenues calculated via PowerSIMM. There are additional revenues not included in  
9 PowerSIMM, including the MISO Day 2 revenues, capacity sales, real-time load and  
10 generation deviation, and revenues from sales of ancillary services. All of the above  
11 expenses and revenues are then segregated between the summer and winter periods to  
12 develop two separate values under Rider FAC. Per Schedule MJL-D17, the summer net  
13 base energy cost of \$168,947,047 was then divided by the normalized Ameren Missouri  
14 summer load at the MISO Node AMMO.UE of 11,670,000,000 kWhs to arrive at a summer  
15 value expressed in cents per kWh of 1.448 cents. The winter net base energy cost of  
16 \$273,499,514 was then divided by the normalized Ameren Missouri winter load at the  
17 MISO Node AMMO.UE of 20,840,188,374 kWhs to arrive at a winter value expressed in  
18 cents per kWh of 1.312 cents.



1 for the delivery of the product. The revenue lag actually consists of three components as  
2 follows: the service lag, which is the number of days from the mid-point of the service  
3 period to the meter reading date; the billing lag, which is the time between when the meter  
4 is read and the bill is sent; and the collections lag, which is the time between when the bill  
5 is sent to the customer and when the customer's payment is received by the Company.

6 **Q. Please explain the expense lead in more detail.**

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

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

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

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

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

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

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

7           **Q.    How was the base revenue lag determined?**

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

16           **Q.    What is meant by service lag?**

17           A.    The service lag refers to the number of days from the mid-point of the  
18 service period to the meter reading date for that service period. Using the mid-point  
19 methodology, the average lag associated with the provisioning of service was 15.21 days  
20 (365 days in the year divided by 12 months divided by 2).

21           **Q.    What is meant by billing lag?**

22           A.    Billing lag refers to the average number of days from the date on which the  
23 meter was read until the customer was billed. The billing lag was determined by analyzing

1 the Company's monthly billing schedules and meter reading records. The average billing  
2 lag was determined to be 0.99 days.

3 **Q. What is meant by collections lag?**

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

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

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

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

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

20 **Q. How were uncollectible revenues treated in your analysis?**

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

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

2           A.    The calculation of the overall base revenue lag, by lag component, is  
3 summarized in the following table. Please note that the revenue lag pertains to revenue lag  
4 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

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

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

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

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



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

3           A.    In prior cases, the Commission Staff has argued that pass-through taxes are  
4 not generated as a result of the provisioning of a service by the utility.<sup>6</sup> Therefore, in these  
5 proceedings a revenue lag which excludes a lag associated with the provisioning of utility  
6 service has been applied to the pass-through tax revenues.

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

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

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

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

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

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

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<sup>6</sup> 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).

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

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

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

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

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

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

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

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

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

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

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

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

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

22 A. The Company purchases and owns all of its current nuclear fuel. At the time  
23 the nuclear fuel is purchased, it is included in construction work in progress ("CWIP") and

1 accrues an Allowance for Funds Used During Contraction ("AFUDC"). The nuclear fuel  
2 accrues AFUDC until it arrives at the reactor site. At that time, the nuclear fuel is in stock  
3 and the AFUDC ceases. When the nuclear fuel assemblies are loaded into the reactor, they  
4 are moved from stock to in service. The nuclear fuel is then amortized to expense each  
5 month as it is burned. The average unburned nuclear fuel is included in the materials and  
6 supplies inventory in rate base. Therefore, the only lag is between the monthly burn  
7 charged to expense and when this expense is recovered in revenue. Thus, a service lag of  
8 15.21 days is used for the expense lead.

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

11 A. Invoices related to purchases of coal were examined to determine the  
12 expense lead time associated with the Company's coal purchases. When weighted by the  
13 dollar amounts shown in the invoices examined, a weighted average expense lead time of  
14 14.43 days was determined.

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

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

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

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

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

3           A.    The Company purchases electricity from MISO and as required under its  
4 contract with the Pioneer Prairie Wind Farm. Based on an examination of the service  
5 periods and payment dates for the Company's sources of purchased power, a weighted lead  
6 time of 18.10 days was determined.

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

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

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

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

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

22           2)    Missouri Sales Tax: Missouri sales tax is payable to the Missouri  
23 Department of Revenue and was calculated as a percent of billings less a 2 percent timely

1 payment allowance. Estimated payments were made weekly with the tax return and  
2 remaining balance due. Taking this information into account, a weighted expense lead time  
3 of 9.31 days was determined.

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

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

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

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

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

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

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

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

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

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

14          A.     Gross receipts taxes are payable to municipalities and counties and are paid  
15     as a percent of billings to customers within the taxing authority. These taxes are paid on  
16     the last day of the month following the end of a month with the exception of Arnold,  
17     Brentwood, Cape Girardeau, Chesterfield, Clayton, Dexter, Fenton, Florissant, Jefferson  
18     City, Jennings, Kirksville, Ladue, Maryland Heights, Moberly, St. Louis County, and  
19     Wentzville that are paid on the 20th day of the month. Based on the specific tax periods of  
20     the various taxing authorities, a dollar-weighted gross receipts tax expense lead time of  
21     26.99 days was calculated.

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

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

4           **Q.    Please explain.**

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

9           **Q.    How did your study address federal income taxes?**

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

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

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

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

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



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

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

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

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

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

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



