Exhibit No.:	
Issue(s):	Tax Normalization
Witness:	Mitchell Lansford
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	GR-2024-0369
Date Testimony Prepared:	May 2, 2025

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. GR-2024-0369

SURREBUTTAL TESTIMONY

OF

MITCHELL LANSFORD

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
May 2025

TABLE OF CONTENTS

REBUTTAL TESTIMONY

OF

MITCHELL LANSFORD

FILE NO. GR-2024-0369

I. INTRODUCTION

Q. Please state your name and business address.

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

Q. Are you the same Mitchell Lansford that submitted supplemental direct testimony in this case?

A. Yes, I am.

Q. To what testimony or issues are you responding to in this surrebuttal testimony?

A. I will address the rebuttal testimony of Office of Public Counsel ("OPC") witness John Riley regarding the Company's potential inadvertent normalization violation.

II. POTENTIAL NORMALIZATION VIOLATION

Q. Please summarize OPCs recommendations regarding the Company's potential inadvertent normalization violation.

A. OPC witness Riley points out that this very same topic was at issue in File No. ER-2024-0319, while attaching his direct and surrebuttal testimony on this topic. Mr. Riley's recommendation is for the Company to seek and obtain its own Private Letter Ruling ("PLR") to resolve this issue. While Mr. Riley agrees that the Company and Staff have correctly concluded the Company's facts are substantially the same as those included in the three PLR's I attached to my supplemental direct testimony and result in an inadvertent normalization violation if one is to be limited to the contents of those three PLRs, Mr. Riley contends that questions or additional information were not fully considered by the Internal Revenue Service ("IRS") in those PLRs. Mr. Riley refers to this open question or additional information that he is seeking using the terms "duality" and "dual use." In short, his concern is that Ameren Corporation benefits from Net Operating Loss Carryforwards ("NOLCs") before the NOLCs are reduced to zero (eliminated from rate base) for Ameren Missouri regulatory purposes. While it is true that at a moment in time Ameren Corporation will have recognized the tax deduction resulting from a NOLC while also including that NOLC in Ameren Missouri's rate base, it is also true that Ameren Missouri customers will benefit from NOLC through a rate base reduction in a future period (timing) and as measured under the separate return approach. Additionally, Mr. Riley contends that the cost of the Company seeking a PLR as a result of Commission Order in this case should be allocated in part to other Ameren subsidiaries.

Q. How do you respond to Mr. Riley's direct testimony from File No. ER-2024-0319 which he attached to his rebuttal testimony in this case?

A. My response is the same as I responded in my rebuttal testimony in File No. ER-2024-0319, which I have attached as Schedule MJL-S1.

Q. Do you share Mr. Riley's dual use concern?

A. I do not. Mr. Riley's dual use concern is one of timing, not whether customers will benefit from the tax deductions arising from NOLCs. The timing difference between when the Company (including parent company) recognizes the benefit of a tax deduction and when that benefit is reflected in customer rates is inherent and fundamental to the normalization rules. Investment Tax Credits ("ITCs") that are claimed in order to offset tax liabilities on a utility's tax return are subject to normalization rules.[1] A utility will benefit from ITCs when claimed on its tax return and provide that benefit to customers in future periods, over the life of the asset. The same timing difference that Mr. Riley refers to as dual use is present in this scenario.

Q. If the Commission orders the Company to seek a PLR to resolve this issue, should the costs of complying with that order be allocated to any other Ameren subsidiary?

A. Likely not. Simply because a PLR could "have a bearing" on other Ameren subsidiaries does not mean the incurrence of the cost to seek a PLR would provide any use, value, or benefit to other Ameren subsidiaries. The instance that I can think of where some sort of cost allocation may have merit is if multiple different regulators of the Ameren subsidiaries ordered the utilities to seek PLRs to resolve this same issue on approximately the same timeline.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

[1] The Company's preferred tax strategy relating to ITCs is to transfer or sell them to a third party. Upon transfer, normalization rules do not apply. The ability to transfer ITCs did not exist until the Inflation Reduction Act ("IRA") took effect. Utilities have a long history of normalizing ITCs prior to the IRA.

Exhibit No.:	
Issue(s):	Transmission Expense, Meramec Expenses, tax issues, Equity Issuance Costs, and cash working capital
Witness:	Mitchell Lansford
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2024-0319
Date Testimony Prepared:	January 17, 2025

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2024-0319

REBUTTAL TESTIMONY

OF

MITCHELL LANSFORD

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
January 2025

TABLE OF CONTENTS

REBUTTAL TESTIMONY

OF

MITCHELL LANSFORD

FILE NO. ER-2024-0319

I. <u>INTRODUCTION</u>

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. Are you the same Mitchell Lansford that submitted supplemental direct testimony in this case?

A. Yes, I am.

Q. To what testimony or issues are you responding to in this rebuttal testimony?

A. First, I will address Staff's proposed method relating to transmission expenses and the direct testimony of Staff witness Karen Lyons on that issue. Second, I will address Staff's proposed exclusion of the remaining Meramec regulatory asset from rate base and the direct testimony of Staff witness Keith Majors on that issue. Third, I will address the direct testimonies of Staff witness Lisa Ferguson and Office of Public Council ("OPC") witness John Riley regarding the Company's potential inadvertent normalization violation. Fourth, I will address Mr. Riley's proposed treatment of disposal loss income tax deductions. Fifth, I will address Ms. Ferguson's proposed amortization period for equity issuance costs. Sixth, I will address Staff witness Paul Amenthor's recommendation for payroll lead times. Seventh, I will address Mr. Riley's recommendation for income tax lead times.

Q. Are you sponsoring any schedules as part of this rebuttal testimony?

A. Yes. I am sponsoring Schedules MJL-R1 through MJL-R3. Schedule MJL-R1 is Staff's response to Company Data Request 0680 relating to transmission expenses. Schedule MJL-R2 is a narrative explanation of accounting for utility income taxes under the normalization method. Schedule MJL-R3 is a simplified example of the normalization method of regulation for income taxes that I will use to respond to Mr. Riley's position on disposal loss deductions.

II. TRANSMISSION EXPENSES

Q. Please describe Staff's position regarding transmission expenses.

A. Staff analyzed Ameren Missouri's actual transmission expenses for the period of January 2018 through June 2024 and found that Ameren Missouri's transmission expense has increased every year.[1] A primary driver of the increases is MISO[2] Multi-Value Project[3] ("MVP") transmission charges for transmission additions and improvements that provide regional benefits and are thus allocated across the MISO footprint (Schedule 26-A costs).[4] Staff witness Karen Lyons states that she annualized transmission expenses as of June 30, 2024. Staff's workpapers reflect the inclusion of the trailing twelve months of transmission expenses as of June 30, 2024, in its direct case revenue requirement.[5] Staff

[1] File No. ER-2024-0319, Karen Lyons Direct Testimony, pp. 4, ll. 7-9
[2] Midcontinent Independent System Operator.
[3] MISO's Multi-Value Projects are regional transmission solutions that are eligible for regional/subregional cost sharing and support one or more of the following three goals (1) Reliably and economically enable regional public policy needs; (2) Provide multiple types of regional economic value; or (3) Provide a combination of regional reliability and economic value. The proposed MVP projects provide benefits in excess of costs throughout the MISO footprint or subregions with project expenses being broadly shared.
[4] File No. ER-2024-0319, Karen Lyons Direct Testimony, pp. 4, ll. 8-9.
[5] File No. ER-2024-0319, Karen Lyons Direct Testimony pp. 4, ll. 13.

further states its intention to re-examine these costs at true up using data through December 31, 2024.[6]

Q. Please compare and contrast the Staff's position with the Company's.

A. The Company's position is to true up transmission expenses using transmission rates in effect as of January 1, 2025. This is achieved by multiplying the January 1, 2025 rate derived from MISO Transmission Owner's revenue requirements on file and in effect at MISO by the most recent 2024 load (billing determinants). This approach is essentially the same approach used to true-up fuel costs (where we take the January 1 prices and apply them to historical volumes) and payroll (where we take January 1 wages and salaries and apply them to December 31 (the true-up date) headcount). However, Staff's revenue requirement ignores these January 1 transmission rates and thus omits known and measurable[7] increases in MISO charges to the Company that are assessed under MISO Schedule 26-A (and MISO Schedule 9) for transmission service taken under MISO's FERC[8]-approved tariffs associated with serving the Company's load.[9] While the Company has included these known and measurable increases in its revenue requirement, Staff has ignored them and is instead using transmission rates that are out-of-date by as much as twelve months.

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[6] File No. ER-2024-0319, Karen Lyons Direct Testimony, pp. 4, ll. 15-16.
[7] Staff agrees that such January 1, 2025, cost changes are known and measurable. Refer to Schedule MJL-R1.
[8] Federal Energy Regulatory Commission.
[9] I will focus this testimony on MISO Schedule 26-A and MISO Schedule 9 costs as collectively these costs reflect the vast majority of the Company's transmission expenses. The Company is required to pay these charges by MISO's FERC electric tariff.

Q. Please describe MISO Schedule 26-A costs and the process for MISO's determination of these costs.

A. Schedule 26-A collects the Attachment MM[10] revenue requirement related to MISO's Multi-Value Projects. Schedule 26-A represents approximately two-thirds of the Company's MISO transmission expenses billed to Account 565. Schedule 26-A has been increasing historically and as I will discuss later is expected to continue to increase as a result of MISO's Long Range Transmission Planning ("LRTP"), as more Multi-Value Projects are completed and placed in-service by the constructing MISO Transmission Owners. Since the vast majority of Transmission Owners constructing Multi-Value Projects update their annual revenue requirement each January, the total revenue requirement, and the resulting new transmission rates to be charged to each transmission customer, generally increase each January. For reference, these Transmission Owners calculate and post their rate calculations in September or October for stakeholder review. The MISO Transmission Owners are also required to hold a joint stakeholder meeting for regional cost-share projects by November 1 of each year. MISO then determines the updated and final total revenue requirement to be collected beginning January 1 of each year.

Q. Please describe MISO Schedule 9 transmission costs and the process for MISO's determination of these costs.

A. MISO Schedule 9 costs generally follow the same process as MISO Schedule 26-A costs. The Company began paying transmission service rates under Schedule 9 effective January 1, 2023. The new revenue requirement and resulting new rate

[10] Attachment MM is a part of MISO's FERC electric tariff and reflects the revenue requirement for each MISO Transmission Owner arising from Schedule 26-A transmission projects.

arose from FERC's November 1, 2022, approval of MISO's Tariff filing to add Missouri Joint Municipal Electric Utility Commission ("MJMEUC" or "MEC") as a MISO Transmission Owner in pricing zone 3B, also referred to as the Ameren Missouri ("AMMO") Pricing Zone, effective January 1, 2023.[11] MJMUEC's addition to the pricing zone is the result of the Hannibal Project, a jointly developed project between Ameren Missouri and MJMUEC. FERC approved the joint ownership agreement on April 7, 2022 in Docket No. ER22-1001. MJMEUC, Citizens Electric, and Ameren Transmission Company of Illinois ("ATXI") continue to make investments in the AMMO Pricing Zone, which results in cost increases to the Company holding all else constant. MISO Schedule 9 reflects investments made specifically in the AMMO Pricing Zone, whereas MISO Schedule 26-A reflects a set of investments that impact the MISO footprint more broadly. Similar to MISO Schedule 26-A costs, generally transmission owners update their annual revenue requirement each January, producing new transmission rates on January 1. For reference, these Transmission Owners calculate and post their rate calculations in September or October for stakeholder review. The MISO Transmission Owners are also required to hold a joint stakeholder meeting for regional cost-share projects by November 1 of each year. MISO then determines the updated and final total revenue requirement to be collected beginning January 1 of each year and sets the rates to do so as of that date.

Q. Has Staff been consistent in its recommendation in this case with its recommendations regarding similar transmission costs in prior cases?

A. No.

[11] Docket No. ER22-2768.

Q. Has Staff identified any new facts or new understanding of the facts that would lead to inconsistent recommendations over time?

A. No. As I will demonstrate in this testimony, there are no substantive new facts that could reasonably justify Staff making inconsistent recommendations on this issue over time.

Q. How have these expenses been treated by Staff in prior cases?

A. In File No. ER-2016-0179, both the Company and the Staff agreed that the known and measurable increase in Schedule 26-A expenses that was effective January 1, 2017 (the true-up date in that case was similarly December 31, 2016) should be included in the Company's revenue requirement used to set rates in that case.[12] Figure 1 below is an image of Staff's workpaper for Schedule 26-A costs in File No. ER-2016-0179:[13]

[12] Although minor differences in the exact amount existed.

[13] Staff's rebuttal workpaper from File No. ER-2016-0179 shown here includes transmission expenses recorded to FERC Account 565 totaling $53,896,098. This total agrees to Staff's Direct Testimony Accounting Schedule 9, page 3 of 6, line 86 column M, total FERC Account 565 Expenses included in Staff's revenue requirement.

FIGURE 1 – STAFF'S 2016 TRANSMISSION EXPENSE RECOMMENDATION

			Staff Annualized Amount
11	Schedule		
46	MISO TRANSMISSION EXPENSES:		
49			
50	1	Scheduling, System Control, and Dispatch	($174,952)
51	2	Reactive Supply and Voltage Control	($401,624)
52	7 & 8	Basic Transmission Revenue	($7)
57	26	Network Upgrade Charge From MTEP	($9,801,261)
58	26A	ARR Pass-Through Associated with MVPs 3/	$284,243
59	26A	MVP Charges (was previously included in 26, split began in Jan 2012)	($33,594,820)
60	26A	Increase for 2017 - 19.07% overall MISO increase (See DR 458HC Tab)	($7,353,118)
61	33	Blackstart Service	($9,514)
62	45	Cost Recovery of NERC Recommendation or Essential Action	$0
63		**Total**	
64			
65		**Entergy Related Charges**	
66	1	Scheduling, System Control, and Dispatch	($24,494)
67	2	Reactive Supply and Voltage Control	($93,100)
68	9	Schedule 9	($1,586,582)
69	11	Wholesale Distribution Charges	($95,976)
70	41	Storm Securitization Charge	($21,929)
71	42A	Accrued and Paid Interest	($31,679)
72	42B	Credit Associated with AFUDC	$4,991
73	47	MISO Transition Cost Recovery	$0
74		**Total Entergy Charges**	
75			
76	**TOTAL MISO EXPENSES**		
77			
78	**Non-MISO 565 Expenses (Transmission By Others)**		($996,276)
79			
80		Total	($53,896,098)
81			

As is clear from Staff's workpaper, the row labeled "26A Increase for 2017 – 19.07% overall MISO increase" reflects Staff's position that a known and measurable increase of $7,353,118 for Schedule 26-A rates effective January 1, 2017, was included in Staff's revenue requirement based upon a trued-up test year in that case ending December 31, 2016.

Similarly, Figure 2 below is an excerpt from a true-up workpaper Staff provided to the Company in File No. ER-2019-0335:

FIGURE 2 - STAFF'S 2019 TRANSMISSION EXPENSE RECOMMENDATION

11	Schedule		Staff Annualized Amount
49	**MISO TRANSMISSION EXPENSES:**		
52			
53	1	Scheduling, System Control, and Dispatch	($163,810)
54	2	Reactive Supply and Voltage Control	($398,464)
55	7 & 8	Basic Transmission Revenue	($989)
58	10D & 10E	Demand and Energy Charge (previously split - unhide rows above)	($7,250,962)
59	10F	FERC Annual Charges	($2,976,559)
60	26	Network Upgrade Charge From MTEP	($15,357,115)
61	26A	ARR Pass-Through Rev Associated with MVPs 3/	$224,033
62	26A	MVP Charges (was previously included in 26, split began in Jan 2012)	($50,408,592)
63	26A	2020 MVP Increase Added to 2019 Actual	($3,078,137)
64	26C	TMEP Constructed by MISO TO's	$0
65	26D	TMEP Constructed by PJM TO's	$ (398)
66	33	Blackstart Service	$ (6,893)
67	45	Cost Recovery of NERC Recommendation or Essential Action	$ -

Note the line titled "26A 2020 MVP Increase Added to 2019 Actual". This reflects Staff's position that a known and measurable increase of $3,078,137 for Schedule 26-A rates effective January 1, 2020, was included in Staff's revenue requirement, based on a trued-up test year in that case of December 31, 2019. Staff Witness Lisa Ferguson provided Staff's testimony in both Files No. ER-2016-0179 and ER-2019-0335.

Although I am not aware of any history prior to 2022 relating to Schedule 9 rate changes that are effective at the beginning of a new year (as noted, these mandated charges arose starting in 2023), the facts relevant to Schedule 9 (i.e., a new expense level to the

Company became effective on January 1st) are exactly the same as those relating to Schedule 26-A in both of the prior cases discussed above.

Staff witness Karen Lyons provided Staff's testimony in File No. ER-2022-0337 and made the same recommendation as she makes in this case. Ms. Lyon's purported justification in File No. ER-2022-0337 for changing Staff's method from prior cases was that the Company's and Staff's prior method was a "forecast" and was not known and measurable as a result.

Q. Does Staff contend in this current case that the Company's method is a forecast or not known and measurable?

A. No. Staff does not address January 1, 2025, transmission expense changes in its direct testimony. However, the Company has had extensive discussions[14] with Staff on this topic. A result of those discussions was Staff's response to a data request that I have attached to this testimony as Schedule MJL-R1. In response to part 2 of this data request, Staff appropriately identifies the transmission revenue requirements in effect on January 1, 2025 as known and measurable, which contradicts the position Ms. Lyons took in File No. ER-2022-0337, but is entirely consistent with the position Staff took in the cases before then, as noted above.

[14] Just as the Company had with Ms. Ferguson back in 2016 and 2019, which led to Ms. Ferguson supporting the Company's method.

Q. Is there any known and measurable data point that would provide for a better representation of going forward expense levels than the in-effect MISO revenue requirements that transmission rates are designed to recover?

A. No. Staff is ignoring the most relevant data point while transmission expenses are increasing substantially. This will only result in the Company failing to recover its costs or producing an even greater deficit in its recovery of these costs.

Q. Did the level of transmission expenses reflected in customer rates resulting from File No. ER-2022-0337 fail to fully cover the transmission costs the Company incurred when those rates were in effect?

A. Yes. While the case was settled and transmission expenses were not specifically stated in the settlement, all parties' recommendations for cost recovery (including the Company's method) fell short of the actual costs the Company experienced during the first twelve months after new customer rates were implemented because these costs continue to rise year over year. From July 2023 to June 2024,[15] combined Schedule 26-A and Schedule 9 transmission costs were $67.5 million. In this prior case, Staff's recommendation of $62.7 million of cost recovery produced an annual shortfall in cost recovery of $5.1 million. The Company's recommendation of $64.9 million more closely matched future costs but still produced an annual shortfall in cost recovery of $2.6 million. The customer rates from File No. ER-2022-0337 are still in effect and have produced *incremental* recovery shortfalls of $7 million (Company's method) to $8 million (Staff's method) through December 2024. Even further *incremental* recovery shortfalls will be produced from December 2024 to the date new customer rates take effect as a result of this

[15] The first twelve months after customer rates were reset in File No. ER-2022-0337.

case. If Staff's approach in this case were accepted, this ongoing recovery shortfall will simply get worse.

Q. Looking back to File No. ER-2019-0335, did the transmission expense reflected in the Company's rates fail to cover its transmission expenses as a result of the customer rates implemented in that case under either method?[16]

A. Yes. While this case too was settled and transmission expenses were not specifically stated in the settlement agreement, all parties' recommendations (including the Company's method) for cost recovery fell short of the actual costs the Company experienced during the first twelve months after new customer rates were implemented. From April 2020 to March 2021[17] Schedule 26-A costs were $53.9 million. In this prior case, Staff's *newer* method from this case would have resulted in a lower recommendation, $50.4 million, and would have produced an even greater annual shortfall in cost recovery of $3.5 million. The Company's consistent method and recommendation of $53.5 million more closely matched future costs but still produced a lower annual shortfall in cost recovery of $0.5 million.[18]

[16] File No. ER-2021-0240 is not relevant to this sort of lookback analysis given the true-up date in that case was September 30, 2021, and thus no party proposed utilizing January 1, 2022, MISO transmission rates as the information from MISO was not available at that point in time. The information to perform a lookback analysis relating to ER-2016-0179 is not readily available due to the Company's implementation of new general ledger system. However, given the relationship between rising costs and setting customers rates based on historical costs it stands to reason that the Company's rates would have similarly failed to cover its transmission costs in these scenarios as well. It is just a matter of the extent to which the Company failed to recover its transmission costs.

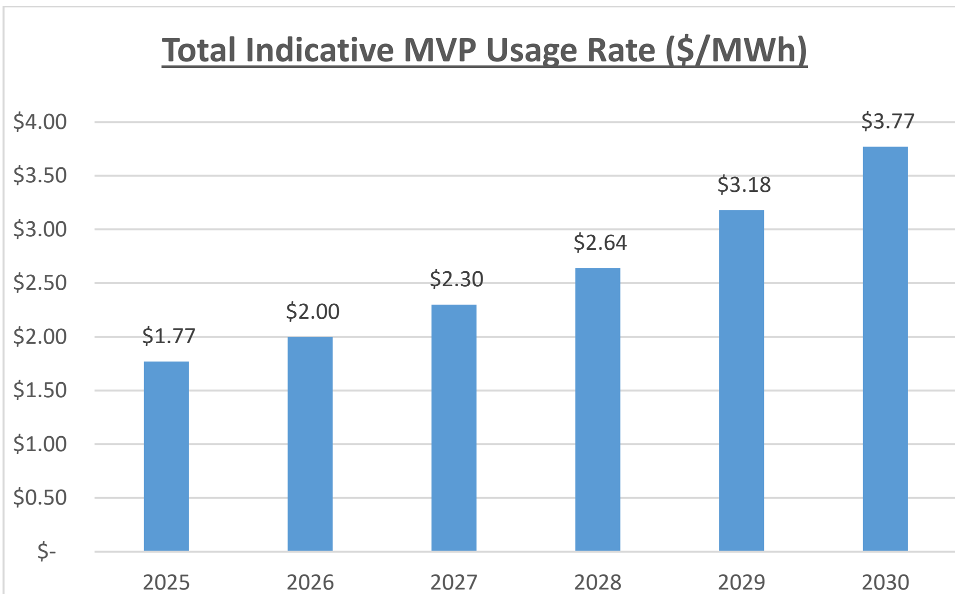
[17] The first twelve months after customer rates were reset in File No. ER-2019-0335.

[18] Staff performed certain lookback analyses in its true-up rebuttal of File No. ER-2022-0337 as evidence of its conclusion at the time that the Company's method was not known and measurable. Staff no longer appears to reach that conclusion in this case. Staff's prior lookback analyses were fundamentally flawed and I will address those flaws if Staff relies on them in this case.

Q. What is MISO's expectation of transmission rates over the next five years?

A. MISO expects these rates and related costs to the Company to increase substantially into the future. Figure 1[19] below reflects a 16% average annual increase in Schedule 26-A rates resulting from MISO's execution of its LRTP.

FIGURE 3 – MISO TRANSMISSION EXPENSE INCREASES



Q. What is Staff's expectation of future transmission expenses?

A. I provided this same graph to Staff months ago and directed Staff to the MISO website to review its source and other pertinent information regarding MISO's LRTP agenda and impacts to transmission costs in the future. However, according to Schedule MJL-R1, Staff inexplicably "does not have an opinion on whether these costs will

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[19] MISO's forecast for MVP rates, available at https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fcdn.misoenergy.org%2FSchedule%252026A%2520Indicative%2520Annual%2520Charges106365.xlsx&wdOrigin=BROWSELINK (accessed on November 4, 2024).

increase." This makes little sense given the long trend of increasing transmission rates and the available information from MISO itself.

Q. Is the expectation of future cost increases relevant to Staff's position?

A. In Staff's own words, it is. When asked in Schedule MJL-R1 why the Company's and Staff's prior method of calculating transmission expenses was appropriate in 2016 and 2019, Staff responded because the positions "were based on significant material increases." The cost increases were 19% and 6% in 2016 and 2019, respectively. The cost increases the Company is experiencing today are similarly significant and material by Staff's own historical standard.

Q. Is there anything else you find concerning about Staff's response at Schedule MJL-R1?

A. Yes. The Company's recommendation relies on the transmission rates in effect January 1, 2025, and 2024 load (sometimes referred to as billing determinants). The Company attempted to confirm with Staff whether those historical billing determinants are known and measurable, to which Staff responded it "did not review MISO transmission invoices." The MISO transmission invoices (all parts including the billing determinants) are the support that ultimately underlies the financial data Staff relied on to take its position in this case. I cannot understand why Staff would not confirm the billing determinants they relied upon in this case are known and measurable. Regardless of Staff's review of the invoices themselves, Staff should still be able to form an opinion on whether billing determinants are known and measurable. The Company was billed based on those billing determinants and paid MISO based on those billing determinants, making all components of the invoices known and measurable.

Q. Why is it important for Staff to provide substantial justification for changing such a significant recommendation from its prior method?

A. It is important so that all stakeholders, including the Company and the Commission, can evaluate if such a change is appropriate. All stakeholders rely on the Commission to make fair, consistent and predictable decisions. Such decisions make settlement of cases more possible. They also improve a utility's access to capital, because investors and analysts favor a predictable regulatory environment. For these reasons, the Commission should only make inconsistent decisions on an issue from case-to-case if there is substantial justification supporting the change. The inability, unwillingness, or otherwise complete absence of justification for change is at best a waste of time and resources and at worst undermines the Commission's ability to apply its rules and enabling statutes to all of the utilities under its jurisdiction in a fair, consistent, and predictable manner.

III. MERAMEC REGULATORY ASSET

Q. Please summarize Staff's position in this case related to the unrecovered Meramec investment arising from the Unanimous Stipulation and Agreement in File No. ER-2021-0240.

A. Staff simply states no carrying costs should be allowed on this outstanding balance because the Commission ordered as such in a recent Evergy West rate case relating to unrecovered investment in Evergy West's Sibley plant.[20] In line with its stated position, Staff excluded the remaining unrecovered balance from rate base in its revenue requirement.

[20] File No. ER-2024-0319, Keith Majors Direct Testimony, p. 5, ll. 6-8.

Q. Did Staff express an opinion on the inclusion of these Meramec costs in rate base in any prior case?

A. Yes. In File No. ER-2021-0240 Staff witness Lisa Ferguson said, "Staff is also not opposed to the proposal regarding carrying costs."[21] The Company's proposal to which Staff witness Ferguson referred in making that statement was "Any difference between the rate base component of the base amount included in this revenue requirement and related future actual costs should be deferred and *included in rate base* in the Company's future rate cases, until fully recovered or refunded" and "Carrying costs equal to the Company's weighted-average-cost-of-capital should be applied to deferrals *included in rate base*."[22]

Q. Are the pertinent facts for the Meramec plant the same as for Evergy West's Sibley plant?

A. Not at all. In File No. ER-2021-0240, the Company recognized that, despite the fact that the then-current depreciation rates were sufficient to recover the remaining plant balance during the time when the plant was still providing service, including the full remaining costs of the Meramec plant in base rates in that case would fully recover the remaining costs over the 10 months of remaining operations of the plant (between the expected effective date of new rates in that case and December 31, 2022, the retirement date), but customer rates would remain elevated as a result of these costs until new rates could take effect in a future case (i.e., with the benefit of hindsight, through July of 2023. Rather than have rates stay in effect that were too high during that period and potentially track them for future return to customers, the Company proposed, and parties ultimately agreed, to simply spread the recovery of the remaining costs over a 5-year period instead

[21] File No. ER-2021-0240, Lisa Ferguson Rebuttal Testimony, p. 4 l. 23, p. 5 l. 1.
[22] File No. ER-2021-0240, Lansford Direct, p. 10, ll 4-15, March 31, 2021 (emphasis added).

of 10 months. As a result of this agreed-upon treatment, the costs at issue associated with Meramec are not an unrecovered balance of plant costs in the way one would normally think about that term – like something to potentially apply securitization to. They are rather costs of providing service during the plant's life, but which are deferred in order to spread the rate impact on customers over multiple years. These costs absolutely relate to costs of providing service during the plant's life.

This deferral treatment was, however, a great outcome for customers, as base rates were reduced approximately $50 million as part of File No. ER-2021-0240 as compared to what they otherwise would have been. Obviously, this outcome had a smoothing effect on customer rates as well. No part of this balance would remain unrecovered at this point in time if the Company had not *voluntarily* made this customer-focused proposal in File No. ER-2021-0240, a proposal that was ultimately approved by the Commission.

The facts surrounding Evergy West's Sibley plant are different in that the plant closed earlier than anticipated at a time when all investment and costs were included in the revenue requirement used to set customer rates. No element of the Sibley facts included a proactive, customer-focused proposal to lower rates as compared to more traditional recovery methods. In fact, the facts relating to Sibley were that the Office of Public Counsel and the Midwest Energy Consumers Group filed a complaint against Evergy West to require that investment and costs associated with Sibley be deferred to a regulatory liability for return to customers.[23]

[23] File No. EC-2019-0200, *Report and Order*, filed October 17, 2019.The Commission generally sustained the complaint and ordered the deferral.

Q. Why is it good regulatory policy for Staff and the Commission to support the Company's and Ms. Ferguson's prior recommendation to include the remaining balance in rate base?

A. The primary reason is so that the Company and other electric utilities could repeat this customer-rate-reducing arrangement, without significant financial detriment, for at least some of the numerous coal-fired generating facilities that will retire over the coming decades. If the Commission were to agree with Staff in this case and determine, effectively, that no good deed should go unpunished, the approximately $2 million of financing costs (annually) that the Company is incurring on the remaining balance today would never be recovered. And all utilities would be disincentivized to propose these types of solutions that are beneficial to its customers simply because it risks being financially harmed by the proposal later.

IV. POTENTIAL NORMALIZATION VIOLATION

Q. Please summarize Staff's recommendations regarding the Company's potential inadvertent normalization violation.

A. Staff witness Ferguson appears to agree with the Company that the pertinent facts in the Private Letter Rulings ("PLRs") attached to my supplemental direct testimony are substantially the same as the Company's facts, meaning failing to measure Net Operating Loss Carryforwards ("NOLCs") irrespective of related Tax Allocation Agreement ("TAA") payments would result in a normalization violation.[24] Ms. Ferguson further suggests that it is *not* in the best interest of customers for the Company to seek its own PLR on this issue.[25] Therefore, it is Staff's recommendation that the Company's

[24] File No. ER-2024-0319, Lisa Ferguson Direct Testimony, p. 45, ll. 3-16.
[25] File No. ER-2024-0319, Lisa Ferguson Direct Testimony, pp. 45-46, ll. 17-23 and 1-4.

NOLCs be calculated in accordance with the PLRs and included in rate base in this case. In addition, Ms. Ferguson also expresses an interest in suggestions and presumably continued discussions regarding alternatives to how the benefits of TAA payments received for NOLCs consumed at the parent company can accrue to ratepayers.

Q. What suggestions regarding alternative treatment of TAA payments does the Company have at this time?

A. This is a complicated and sensitive topic. As my supplemental direct testimony outlines, the Internal Revenue Service ("IRS") was quite clear in the previously referenced PLRs that an attempt to circumvent their ruling by producing the same effects of a reduced NOLC would also constitute a normalization violation. For this reason and given the considerable consequences of being found to have knowingly violated the IRS's normalization rules, the Company does not have an alternative for Ms. Ferguson at this time. The Company will continue to monitor this issue and is willing to meet with Staff to discuss this topic further as new information becomes available.

Q. Please summarize OPCs recommendations regarding the Company's potential inadvertent normalization violation.

A. OPC witness Riley has various concerns about the diligence of the IRS[26], whether it is contradicting itself[27], and whether and what "defining action" is required[28]. Ultimately, Mr. Riley recommends that the Commission direct the Company to request clarification on this issue from the IRS[29], which I understand to mean his recommendation

[26] File No. ER-2024-0319, John S. Riley Direct Testimony, p. 8, ll. 1-6
[27] File No. ER-2024-0319, John S. Riley Direct Testimony, p. 9, ll. 11-23
[28] File No. ER-2024-0319, John S. Riley Direct Testimony, p. 9, ll. 7-10
[29] File No. ER-2024-0319, John S. Riley Direct Testimony, p. 10, ll. 2-3

to be that the Company seek its own PLR, and the Commission order the Company to comply with the ruling received.

Q. Do you share Mr. Riley's concerns?

A. I do not. In my experience, the IRS is very thorough and knowledgeable of utility regulation. It's my understanding that the taxpayer involved in the previously mentioned PLRs engaged in a multi-year process with the IRS that led to those rulings. I expect the IRS thoroughly understood every nuance of its rulings.

Q. Mr. Riley makes several unsupported claims. Please identify those claims and indicate whether you agree with each.

A. Mr. Riley indicates that how the IRS views a subject matter is often predicated by how the questions are posed to the reviewer. Mr. Riley provided no support for this claim, and I do not agree with it and refer the Commission to my prior commentary regarding the diligence and knowledge of the IRS. Mr. Riley further claims that the IRS will generally admit that there is no specific defining action related to the phrase "take into account." Again, this claim is unsupported, and it is unreasonable to suggest that when the IRS rules that an "NOLC must be taken into account when considering the effect on rate base" that such a ruling could result in exclusion or inaction. The only reasonable interpretation of this phrasing is that the NOLC must be included in the utility's rate base.

V. DISPOSITION LOSS DEDUCTION[30]

Q. Please describe OPC's position on disposition loss income tax deductions.

A. Mr. Riley claims the Company's disposal loss deductions are not included in Staff or the Company's revenue requirements[31] in this case and as a result, recommends that an average of historical disposal loss deductions[32] be incorporated into the revenue requirement used to set rates in this case presumably via the flow-through method[33] of regulation for utility income taxes.

Q. Please provide a summary of the Company's rebuttal.

A. Mr. Riley was apparently expecting to see a disposal loss deduction labeled in the income tax section of Staff's Accounting Schedules.[34] Staff and the Company's income tax schedules aggregate and summarize deductions that are of like nature, because otherwise these schedules would be as long as a corporate tax return.[35] The tax depreciation line item on each respective schedule contains all reductions in tax basis ("of like nature") for property, plant, and equipment assets, including the disposal loss deductions Mr. Riley was expecting to otherwise see labeled on the schedules. Disposal loss deductions *are* and have historically been included in the Company's and Staff's revenue requirements under

[30] Over the years Mr. Riley has entered these same or similar arguments under the headings of disposition loss deduction, retirement loss deduction, abandonment loss deduction, and impairment loss deduction, along with other variations of these terms. Each can be used interchangeably for purposes of this discussion.
[31] File No. ER-2024-0319, John S. Riley Direct Testimony, p. 4, ll. 9-11.
[32] Mr. Riley's adjustment includes casualty loss deductions in addition to the Company's ordinary disposal loss deductions.
[33] File No. ER-2024-0319, Lisa Ferguson Direct Testimony, p. 38, ll. 1-3. Both the flow-through and normalization methods are accepted methods for utility ratemaking and capable of being implemented to have the exact same impact on customers on a present value basis. The normalization method can be appropriately applied to any temporary difference, whereas the flow-through method cannot be applied to plant-related temporary differences without violated the IRS normalization rules.
[34] File No. ER-2024-0319, John S. Riley Direct Testimony, p. 4, ll. 17-18.
[35] Which consist of 300 pages or more.

the normalization method.[36] Under the normalization method, disposal loss deductions are a component of Accumulated Deferred Income Taxes ("ADIT") that reduces rate base, thus providing the benefit of the deduction to customers from the resulting reduction in the revenue requirement. Schedules MJL-R2 and MJL-R3 provide a narrative explanation of accounting for disposal loss deductions under the normalization method and a detailed example, respectively. Mr. Riley's intent may be to switch from the normalization method for this deduction to the flow-through method. But switching methods would result in a normalization violation,[37] has no benefit, would be costly irrespective of the cost to customers resulting from a normalization violation, and cannot be accomplished with the information available.

Q. Please respond to Mr. Riley's claim that asset disposition deductions do not get recognized in the income tax calculations for ratemaking.

A. This is not true. When an asset is retired before it is fully depreciated for tax purposes, the remaining tax basis in the asset is reduced to zero (disposition loss deduction), essentially reflecting the full and immediate depreciation of that asset for tax purposes.[38] In isolation, that event results in an increase to deferred tax liabilities which in turn decreases the utility's rate base and thus the revenue requirement used to set customer rates. When a retirement event occurs between the Company's rate reviews, Plant-in-Service Accounting ("PISA") deferrals are reduced by this increase in deferred tax liabilities, which in the following rate review will result in a lower PISA deferral revenue

[36] File No. ER-2024-0319 Lisa Ferguson Direct Testimony, pp 37, 38 ln 26-28, ln 1.
[37] As discussed in my Supplemental Direct Testimony, a normalization violation would be extremely detrimental to our customers, because it would result in the Company being denied accelerated depreciation deductions on a go-forward basis.
[38] Cumulative life-to-date tax depreciation deductions plus any asset disposition loss deduction can only equal the value of the asset. The effect is that a company receives a tax deduction for its cumulative costs (original tax basis in the asset), but never more than its costs.

requirement. The Company's and Staff's income tax calculations for ratemaking purposes do in fact reflect book depreciation, tax depreciation (including disposition adjustments in the calculation of tax depreciation), and deferred tax liabilities. In tandem, these elements ensure customers receive the full benefit of this temporary or timing tax difference.

Q. Please respond to Mr. Riley's claim that the federal government allows depreciation to be accelerated to provide a tax break (deduction) that is not allowed to be recognized in ratemaking calculations.

A. Mr. Riley is incorrect. Indeed, Mr. Riley has a fundamental misunderstanding of the IRS's normalization rules. The tax deduction *is* allowed to be recognized in ratemaking calculations *as a component of deferred tax liabilities that offset the Company's rate base*. The result is the benefit of the temporary or timing deduction is recognized over the book life of the asset.[39] This is *exactly* the normalization method of utility regulation for income taxes. Schedules MJL-R2 and MJL-R3 further explain accounting for disposal loss deductions under the normalization method and provide a detailed example.

Q. What is the normalization method of utility regulation for income taxes?

A. The below Figure 4 is independent and objective interpretive guidance;[40]

[39] The book life of the depreciation group, since book depreciation is only determined at the group level.
[40] PricewaterhouseCoopers, LLP US Utilities Guide

FIGURE 4 – INCOME TAX NORMALIZATION GUIDANCE

19.3 Normalization

Publication date: 20 Jul 2016

US Utilities guide

Normalization is integral to accounting for income taxes in a regulated environment and arises from IRC guidance on the ratemaking approach. Normalization is a method of ensuring that regulated utilities benefit from the various tax law provisions that were designed to encourage capital expenditures.

For example, accelerated depreciation and ITCs are intended to encourage capital expenditures, not to subsidize customers' utility costs. However, because these deductions and credits reduce cash income taxes, the tax component of the cost of providing services would be lower, and thus, the rates charged to customers would be lower if these benefits were immediately provided to customers. This lowers the regulated utility's revenues in the short term. Normalization protects revenues from the effects of lower rates, and allows regulated utilities and customers to share the benefits of accelerated depreciation and investment tax credits.

Under the normalization rules, for a regulated utility to claim accelerated deductions on its tax return, its regulator must require that the tax savings be "normalized" over the life of the property. This means that income tax expense in the ratemaking process will be computed as if depreciation was recorded on a straight-line basis, rather than through an immediate reduction in rates (as is the case under flow-through). In other words, the regulated utility determines the income taxes recognized for regulatory purposes based on the amount of depreciation recognized for financial reporting and regulatory purposes. Because regulators allow the recovery of book amounts on an accrual basis, the regulated utility should also consider the related income tax effects of such cost recovery on an accrual basis.

Under the normalization rules, the regulated utility records a reserve against rate base for the difference between the income tax allowance determined in this manner and the amount of income taxes actually paid (i.e., accumulated deferred income taxes or ADIT). That reserve is then drawn down as, for example, the accelerated depreciation benefits reverse in later years. This reduction to rate base for ADIT provides ratepayers with the benefit of the accelerated depreciation deduction received by the regulated utility (which is effectively an interest free loan from the government).

As the above guidance explains, the rate base reduction for ADIT, which is fully reflected in the form of lower rate base and which also reduces the PISA deferrals upon retirement, as I explained earlier, ensures customers receive all of the benefits to which they are entitled.

Q. Please respond to Mr. Riley's claim that when an asset is no longer in service, it is removed from rate base along with the accumulated depreciation and the associated ADIT.

A. Mr. Riley makes this false claim with reference to an exception to the general rule that *only* applies in securitization since the securitization statute in Missouri specifically requires this exception. Specifically, §393.1700 2(3)(c)m of the Missouri Securitization Statute requires that applicable "accumulated deferred income taxes, including excess deferred income taxes, shall be excluded from rate base in future general rate cases… ." This exception is stated because the general rule is just the opposite. Outside securitization, the Company's unrecovered investment in an asset remains in rate base as a component of the depreciation reserve that also remains in rate base, along with the associated ADIT.[41] Mr. Riley provided a second exception to the general rule by attaching an IRS Private Letter Ruling relating to the condemnation of an asset and transfer of that asset to an affiliate that had no property subject to ratemaking but this second exception has no application here. It has no application because the Company's asset disposals do not relate to condemnation or transfer to an affiliate and the Company's assets, unlike the assets involved in the Private Letter Ruling cited by Mr. Riley, *are* subject to ratemaking.

Q. Has the Commission ever issued an order that denied one of Mr. Riley's deduction recommendations?

A. Yes. In File No. EO-2022-0193 Mr. Riley used the "abandonment" terminology, but as I stated previously abandonment can be used interchangeably with the disposal loss terminology he uses in this case. The relevant excerpt from the Commission's *Amended Report and Order* in that case (the "Liberty Order") is as follows in figure 5:[42]

[41] Depreciation rates are studied and (re)designed to recover a utility's unrecovered plant investment.
[42] File No. EO-2022-0193, *Amended Report and Order*, pp. 63-64, Filed September 22, 2022

FIGURE 5 – DISPOSAL LOSS DECISION IN LIBERTY ORDER

N) Should Liberty's recovery reflect a disallowance for income tax deductions for Asbury abandonment?

Findings of Fact

141. Public Counsel asserts that Liberty has enjoyed a tax benefit because it wrote-off Asbury in 2020 and the last three months of 2019. Public Counsel asserts this is a benefit directly associated with the retirement of Asbury and should be included in the AAO totals established to track the costs associated with that retirement. Public Counsel calculated a tax benefit of $16.5 million, which it applied to the AAO liability.[177]

[177] Riley Rebuttal, Ex. 208, Page 19, Lines 7-16.

63

142. This tax benefit is a normal timing item that is treated the same as any ADIT item in rates. A regulatory asset was established for the net book value of Asbury. This regulatory asset has deferred taxes associated with it. As this regulatory asset gets amortized, the amortization expense is added back for taxable income purposes with no corresponding tax deduction because Asbury qualified as an abandonment for tax purposes already.[178]

Decision

Public Counsel's proposed disallowance for income tax deductions for Asbury abandonment is unnecessary and will not be imposed.

Paragraph 141 from the Liberty Order, quoted above, describes Mr. Riley's recommendation in that case substantially the same as he describes in this case. He claims that customers will not benefit from the reduction of tax basis in the asset to zero via the corresponding tax deduction unless the Commission were to accept his recommendation.

Paragraph 142 from the same order is substantially the same as my testimony in this case. That is, as I have explained, the Commission recognized that the deduction in question results in a normal temporary or timing difference that is accounted for via the calculation of ADIT, and that the reduction in rate base resulting from ADIT fairly compensates customers for the deduction.

As one can plainly see, the Commission appropriately concluded that Mr. Riley's recommendation was unnecessary and would not be imposed.

Q. File No. EO-2022-0193 also relates to a securitization transaction. Is it more relevant to the facts in this case than the Commission's Order in the Company's Rush Island Securitization Case?

A. Yes, it is. The Commission's decision on Mr. Riley's position in the Liberty Securitization Case did not relate to the *securitization* aspect of the case which dealt with energy transition costs under the securitization statute. Instead, the decision related to the *prior* treatment of Liberty's Asbury plant *in base rates* and the time period from the retirement date of that facility *to* the issuance of securitized utility tariff bonds. Similarly, the issue at hand here is the treatment of these deductions *in base rates*. Regarding the Company's Rush Island Securitization Case, the facility had not retired at the time of the case and no aspect of that case related to how a disposal loss deduction should or shouldn't be treated in base rates. Instead, the issues that were decided in the Company's Rush Island Securitization Case were concerning how to properly apply the Securitization Statute once the facility retired and once a securitized utility tariff charge was approved and implemented.

Q. What is the "general rule" you previously mentioned?

A. The general rule is that regardless of how you refer to depreciation-related temporary or timing differences, each should *consistently* follow the normalization method of utility income tax regulation. Figure 6[43] below provides recent authoritative guidance that further demonstrates ADIT remains after a normal retirement and the normalization method can therefore continue to be applied.

FIGURE 6 –INCOME TAX ACCOUNTING FOR RETIREMENTS

> 29. Question: Is a regulated entity required to make journal entries to record the tax effects of a retired plant asset that is maintained under the group method of depreciation?
>
> Answer: No. Upon a normal retirement of a plant asset, the simultaneous reduction of both the original cost of the plant and its accumulated depreciation results in no tax effect in the year of retirement under the principles of group or composite depreciation; as such, no adjustment of deferred income taxes is warranted. The Commission previously explained that the use of composite depreciation rates recognizes that some assets within the group will outlive the average useful life of the group while other assets within the group will be retired from service earlier than the group's average life; thus, due to the envisioned offsetting mechanisms within the group, journal entries may not be warranted when there is no tax effect for the entire group in the year of retirement.

This authoritative guidance makes it clear that ADIT is not somehow washed away as a result of a normal retirement. Instead, there is no impact on ADIT as a result of reducing the original cost of plant and reducing the depreciation reserve by like amounts. The above figure is silent on any remaining tax basis in the asset, as that is not the focus of the question, and that circumstance may or may not even exist at the time of any normal retirement. However, this clear evidence that ADIT should remain (and undoubtedly continue to be accounted for in the proper manner) and demonstrates that all the inputs to

[43] Source: Obtained from the FERC website at URL (https://www.ferc.gov/media/accounting-questions-and-answers) on January 2, 2025.

the normalization method described above are to be maintained even after normal retirement of an asset. Logic and reason dictates that since the normalization method is appropriate up to the point of retirement, depreciation and disposal loss deductions are both reductions in tax basis of an asset (of like nature), and ADIT continues on after a normal retirement that a continuation of the normalization method would *continue* to be fair and reasonable to all stakeholders.

Q. Was any amount of plant-related ADIT excluded from the Company's rate base in its revenue requirement in this case?

A. Yes, but only the amount relating to the retirement of the Company's Rush Island Energy Center, which is not at issue or involved in the determination of the revenue requirement in this case at all since the Commission approved securitizing its undepreciated balance in File No. EF-2024-0021. Again, the exception to the general rule.

Q. Has Mr. Riley recommended any amount of plant-related ADIT be excluded from the Company's rate base in this case?

A. No. Mr. Riley has not recommended any amount of ADIT relating to the Company's normal asset disposals be excluded from rate base.

Q. Should Mr. Riley have excluded an amount of plant-related ADIT from the Company's rate base in this case in support of his position?

A. Yes. I have no idea what amount though, because in order to know the proper amount one would have to first know the remaining book basis in every individual asset underlying each depreciation group.[44] The book basis in every underlying asset is not

[44] To the extent the entire book depreciation group is retired at once like was the case for the Company's Rush Island Energy Center, you obviously can compute the book value rather easily. The normal retirements at issue in this case are but a tiny fraction of the respective book depreciation groups associated with the assets being retired.

a record that is maintained or required to be maintained when applying group (or "composite") depreciation, as the Company does. Further, the application of Mr. Riley's position without any of the proper corresponding reduction in plant-related ADIT from rate base would violate the IRS' consistency rules and result in another normalization violation.[45]

Q. What happens when an asset is retired before it has been fully depreciated for tax purposes?

A. As explained above in this testimony, the labeling of the reduction of tax basis that occurs when an asset retires is not meaningful to this process. Whether it is called - depreciation, disposal, impairment, retirement, or abandonment - has no impact. In Schedule MJL-R3, line 5 indicates the tax basis by year. The reduction of tax basis of $200 from year 5 to year 6 could be labeled as any of the above and there would be no impact to any aspect of this example. Similarly, if the tax basis of $400 in year 4 was reduced down to zero in year 5 to reflect an earlier retirement of the asset (replacing the $200 amount in cell F14 with $0) the formulas in the spreadsheet would update and no other changes would be necessary to properly reflect the change. Notably, the Company's total return on investment decreases (as ADIT increases and offsets rate base (i.e., makes rate base lower))

[45] Page 13 of JSR-D-02 states "The failure to eliminate the deferred taxes, including ADIT and the deferred tax reserves on the regulated books of Subsidiary C and Subsidiary D as of the date of the Condemnation, attributable to public utility property condemned in a transaction governed by § 1033 would violate the normalization provisions of § 168(i)(9)." Page 9 of JSR-D-02 states "Section 168(i)(9)(B)(i) provides that one way the requirements of § 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under § 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under § 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base (hereinafter referred to as the "Consistency Rule")."

when an asset is disposed of in advance of its tax depreciable life, on balance providing a financial disincentive to the Company to dispose of assets early.[46]

Q. Should the Commission continue to apply the normalization method to income tax consequences resulting from plant investment?

A. Yes. Customers benefit from each and every deduction through base rates and PISA under current processes. The normalization method has been consistently followed throughout the country, in the State of Missouri, and by the Company in this case. Mr. Riley's repeated attempts to change this process is a recommended solution in search of a problem that does not exist. As a result, changing this longstanding process without good cause would produce a cost without a benefit. All stakeholders, including the Company's customers, are being treated fairly under current processes. It undoubtedly would cost the Company to change its processes, and the inappropriate application of a change could result in some or all stakeholders being harmed (normalization violation) or otherwise treated unfairly.

VI. EQUITY ISSUANCE COSTS

Q. Please describe Staff's recommendation related to the amortization of equity issuance costs.

A. Staff recommends amortization of these costs at $255,447 per year, as set out in File No. ER-2021-0240. The resulting implied recovery period relating to these costs is approximately 30 years. Staff further recommends that the unrecovered balance be excluded from rate base, meaning the Company would be forced to finance these costs over 30 years without recovery of any of the financing costs for doing so. A determination to

[46] The total return on investment in Schedule MJL-R3 cell T24 is $603.75. When making the modification to cell F14 to make this cell $0 (reflecting an early disposal) cell T24 reduces by $3.50 to $600.25.

exclude unrecovered amounts from rate base was *not* set out in File No. ER-2021-0240 or any rate review since.

Q. Please summarize the pertinent history regarding these costs.

A. The Company incurred equity issuance costs directly related to financing its investment in the wind energy centers that were placed in service in 2020. In File No. ER-2021-0240, the Company proposed recovery of equity issuance costs consistent with the recovery of the energy centers (over approximately 30 years) with remaining unrecovered costs included in the Company's rate base. Staff's position was for the Company to recover these costs over five years, but no costs were recommended to be included in the Company's rate base. The Stipulation and Agreement resolving the case reflected recovery over the life of the energy centers and it was unspecified as to whether the remaining unrecovered costs were included in the Company's rate base. In filing this case and File No. ER-2022-0337, the Company fully conceded to Staff's recommendation from File No. ER-2021-0240 by excluding unrecovered costs from rate base and amortizing costs over 5 years in an effort to avoid wasting additional time and resources in front of the Commission on this issue. The Company conceded to that recommendation since the remaining balance is relatively "small" and the remaining recovery period is, in relative terms, fairly short, which substantially mitigated the problem of financing these costs while recovering no related financing costs.

Q. Does the Company agree with Staff's recommendation in this case?

A. No. A recovery period of approximately 30 years is entirely too long if the Company receives no compensation for its financing costs (through inclusion of the unrecovered balance in rate base). The application of Staff's recommendation would result in unrecovered financing costs of approximately $5 million over the remaining term. Any cost forced to be recovered over a long period of time (such as 30 years) while excluding the unrecovered amount from rate base violates the matching principle which Staff often raises by disconnecting the *recovery of* costs the Company has financed from its rate base. Further, Staff's position that would force unrecovered amounts onto the Company violates Staff's stated purpose of developing a revenue requirement to "cover its (the Company's) operating costs and to provide a fair return on investment used in providing electric service."[47]

Q. Does the Company have an alternative position to its position in this case?

A. Yes. The Commission should either accept the Company's recommendation in this case, which again is the same recommendation from Staff in File No. ER-2021-0240 so that these costs will be recovered over five years or accept Staff's recommended amortization period from this case while including $6,279,746 of unrecovered costs in the Company's rate base in this case.

VII. <u>PAYROLL LEAD TIMES</u>

Q. Please describe Staff's position regarding the payroll lead.

A. Staff adjusted the payroll payment lead time for management employees (a component of the broader payroll lead) to zero. The result was an increase in the overall payroll lead from 10.90 (Company) to 12.01 (Staff). Staff's rationale for the change is that "Since there was no change with how management employees are paid (since the Company's lead lag study

[47] File No. ER-2024-0319, Lisa Ferguson Direct Testimony p. 6, ll. 9-10

was performed in 2021), Staff recommends a payroll lag of 12.01 that is consistent with the payroll lag adopted in Case No. ER-2021-0240."[48]

Q. What was Staff's recommendation in File No. ER-2022-0337 regarding this very same lead lag study?

A. After various discussions with Staff witness Jared Giacone and the discovery performed supporting that case, Staff concluded the following in Figure 7:[49]

<u>FIGURE 7 – STAFF'S 2022 CASH WORKING CAPITAL RECOMMENDATION</u>

Direct Testimony of
Jared Giacone

Q. Did Staff disagree with any CWC lead/lag study items in the ER-2021-0240 case?

A. Yes, there were some minor differences noted by Staff in the ER-2021-0240 case. For example, Staff proposed an updated collection lag that the Company agreed with and incorporated in their CWC proposal for the present case. Aside from the collection lag, there are no material differences between the Company's proposed CWC schedule in the present case compared to Staff's true-up CWC schedule.

One of the "minor" differences Mr. Giacone concluded was no longer worth proposing a different position for in that case was the payroll expense lead. The following excerpt (figure 8) from Staff's direct accounting schedules reflects that in that prior case Staff used a 10.90 payroll and withholdings expense lead - see column D line 2.

48 File No. ER-2024-0319, Paul K. Amenthor Direct Testimony, p. 4, ll. 20-22.
49 File No. ER-2022-0337, Jared Giacone Direct Testimony, p. 4, ll. 1-7

FIGURE 8 – STAFF'S 2022 CASH WORKING CAPITAL SCHEDULE

Ameren Missouri
Case No. ER-2022-0337
Staff Direct Accounting Schedules
Updated through June 30, 2022
Cash Working Capital

Line Number	A Description	B Test Year Adj. Expenses	C Revenue Lag	D Expense Lag	E Net Lag C - D	F Factor (Col E / 365)	G CWC Req B x F
1	OPERATION AND MAINT. EXPENSE						
2	Payroll and Withholdings	$324,184,773	37.02	10.90	26.12	0.071562	$23,199,311
3	Other Employee Benefits	$46,437,434	37.02	17.65	19.37	0.053068	$2,464,342
4	Pensions and OPEBs	-$49,059,298	37.02	15.70	21.32	0.058411	-$2,865,603
5	Fuel - Nuclear	$61,253,898	37.02	15.21	21.81	0.059753	$3,660,104
6	Fuel - Coal	$450,258,602	37.02	14.43	22.59	0.061890	$27,866,505
7	Fuel - Gas	$57,083,923	37.02	40.72	-3.70	-0.010137	-$578,660
8	Fuel - Oil	$3,961,478	37.02	14.69	22.33	0.061178	$242,355
9	Purchased Power	$52,268,942	37.02	18.10	18.92	0.051836	$2,709,413
10	Incentive Compensation	$26,297,754	37.02	250.80	-213.78	-0.585699	-$15,402,568
11	Uncollectibles Expense	$8,174,196	37.02	37.02	0.00	0.000000	$0
12	Cash Vouchers	$853,347,992	37.02	42.25	-5.23	-0.014329	-$12,227,623
13	TOTAL OPERATION AND MAINT. EXPENSE	$1,834,209,694					$29,067,576

To summarize, Staff recommended an adjustment to the Company's position in File No. ER-2021-0240, did further discovery on the same exact study in File No. ER-2022-0337, noted minor differences existed prior, consciously agreed with the Company's recommendation in File No. ER-2022-0337 (which is the same recommendation as in this case), and has now reverted back to its position in File No. ER-2021-0240 while completely ignoring its more recent recommendation from File No. ER-2022-0337 (all related to the same exact study performed in 2021).

Q. Do you agree with Staff's recommendation in this case?

A. No. I do not agree with Staff's rationale and the recommendation is at odds with longstanding practice. Historically, the Company has calculated the payment lead-time based on the period from the end of the service period date to the payment date. If a payment is made prior to when services are fully rendered, then the payment lead-time is calculated as a negative payment lead-time. In the past, this methodology has been accepted in calculating the payment lead-time because it reflects accurately the cash needs as compared to expense recognition.

Q. You say that the Commission has accepted a negative payment lead-time in the past for the calculation of the payroll and payroll taxes. Please explain.

A. From time to time, the Company has used a negative payment lead-time for management employees in rate cases that have been approved by the Commission. For example, when a management payroll period fell on a weekend or holiday, the payment date was the preceding business day, which resulted in the calculation of a negative payroll lead-time. This methodology has not changed with the adjustment in management pay dates; it is simply being used on a larger scale. Furthermore, a negative payment lead-time can occur in other categories of payments to meet contractual obligations, such as pre-payment of services. Negative lead times are typically accepted in these other circumstances. Therefore, they should be accepted in addressing the payroll payment lead-time.

VIII. INCOME TAX LEAD TIMES

Q. Please describe OPC's position as it relates to income tax expense lead times.

A. OPC argues a 365-day expense lead should be utilized when calculating the net lag for income taxes, claiming that the Company isn't paying income taxes.[50]

Q. Is it true that the Company has not made quarterly income tax payments?

A. No. The Company's response to OPC's data request 1301 provides the tax payment activity for Ameren Missouri from 2020 through September 2024. I've summarized that activity in Figure 9 below.

[50] File No. ER-2024-.0319John S. Riley Direct Testimony, p. 11, ll. 14-15.

FIGURE 9 – INCOME TAX PAYMENTS BY MONTH AND YEAR

Month	Year				
	2020	2021	2022	2023	2024
March	(32,901)	500			(48,916,000)
April	30,000			(36,718,000)	7,259,500
May				24,314,000	
June	(63,055,000)	(94,589,000)	19,498,000		20,300,000
July	40,000				
September	66,346,000	70,945,000	(5,100,000)	4,481,000	(16,450,000)
November			(1,103,842)	2,879,908	
December	24,631,307	19,521,000	(8,033,181)	34,399,459	

It is obvious that the Company's history of tax payments supports an income tax expense lead of less than 365 days. The Company and Staff's expense lead proposals in this case (which are the same) are reasonable and supported by the Company's history of making quarterly payments.

Q. Are there any other factors the Commission should consider?

A. Yes. I have previously described the normalization method of regulation of utility income taxes and ADIT. The difference between income tax recoveries and income tax payments has already been accounted for via the reduction of rate base by the ADIT balance. Making Mr. Riley's adjustment to cash working capital would double count this effect. Figure 4 in this testimony best describes this from an independent source when it says, "Under normalization rules, the regulated utility records a reserve against rate base for the difference between the income tax allowance determined in this manner and the amount of income taxes actually paid (i.e., accumulated deferred income taxes or ADIT)."

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

1. Is it the Staff's position that the currently in effect transmission revenue requirements for MISO schedules 26-A and 9 are known and measurable? If not, why not?

   Answer: Yes

2. Is it the Staff's position that the transmission revenue requirements for MISO schedules 26-A and 9 posted on the MISO website and to be in effect beginning January 1, 2025 are known and measurable? If not, why not?

   Answer: Yes

3. Are the billing determinants identified on 2023 and 2024 MISO transmission invoices and underlying supporting schedules known and measurable at the time the invoice is issued? Please identify those that are not known and measurable, if applicable, and explain why.

   Answer: Staff did not review MISO transmission invoices

   a. Was Staff's position regarding MISO Schedule 26-A costs in Files No. ER-2016-0179 and ER-2019-0335 substantially similar with the recovery of such costs proposed by the Company in this case?

   Answer: Yes

   b. Was it Staff's position on recovery of MISO Schedule 26-A costs in File Nos. ER-2016-0179 and ER-2019-0335 (relying on the revenue requirements for 26-A charges taking effect on January 1 following the true-up cutoff date in each such case) that such amounts were known and measurable? If not, why not.

   Answer: Yes

   c. Why was Staff's position on recovery of MISO Schedule 26-A costs in File Nos. ER-2016-0179 and ER-2019-0335 in each case appropriate? If Staff contends that its position in each such case was not appropriate, please provide a detailed explanation of why not.

   Answer: Staff's positions for 26A costs in Case Nos. ER-2016-0179 and ER-2019-0335 were based on significant material increases that occurred for 26A costs calculation.

4. As MISO Long Range Transmission Planning ("LRTP") projects are competed and placed in service, does Staff expect MISO Schedule 26-A costs to increase substantially for the Company over the next 5 years? If not, why not?

   Answer: Future MISO Schedule 26-A costs are not known. Staff does not have an opinion of whether these costs will increase in the next 5 years.

Schedule MJL-R2

File No. ER-2024-0319

Accounting for Utility Income Taxes Under the Normalization Method

Tax Basis and the Computation of a Disposal Loss Deduction

Tax basis is defined by the Internal Revenue Service ("IRS")[1] as follows:

> Basis is generally the amount of your capital investment in property for tax purposes. Use your basis to figure depreciation, amortization, depletion, casualty losses, and any gain or loss on the sale, exchange, or other disposition of the property.

A disposal loss deduction is the Company's remaining or adjusted tax basis less any amount the Company is able to realize upon disposal. The IRS describes the various types of disposals as follows:

> You dispose of property when any of the following occur.
>
> - You sell property.
> - You exchange property for other property.
> - Your property is condemned or disposed of under threat of condemnation.
> - Your property is repossessed.
> - You abandon property.
> - You give property away.

The IRS provides further details on the calculation of a loss on disposition via sale as follows:

Gain or Loss From Sales and Exchanges

You usually realize gain or loss when property is sold or exchanged. A gain is the amount you realize from a sale or exchange of property that is more than its adjusted basis. A loss occurs when the adjusted basis of the property is more than the amount you realize on the sale or exchange.

Table 1-1. How To Figure Whether You Have a Gain or Loss

IF your...	THEN you have a...
adjusted basis is more than the amount realized,	loss.
amount realized is more than the adjusted basis,	gain.

[1] References to the IRS and guidance provided by the IRS in this section were obtained from https://www.irs.gov/publications/p544

Adjusted basis. The adjusted basis of property is your original cost or other basis increased by certain additions and decreased by certain deductions. Increases to basis include costs of any improvements having a useful life of more than 1 year. Decreases to basis include depreciation and casualty losses.

Many of the Company's retirements qualify as sales per the IRS rules because the Company frequently realizes salvage proceeds.

The IRS also provides further details on abandonments as follows:

Abandonments

The abandonment of property is a disposition of property. You abandon property when you voluntarily and permanently give up possession and use of the property with the intention of ending your ownership but without passing it on to anyone else. Generally, abandonment is not treated as a sale or exchange of the property. If the amount you realize (if any) is more than your adjusted basis, then you have a gain. If your adjusted basis is more than the amount you realize (if any), then you have a loss.

When the Company disposes of an asset instead of selling it, the disposal also meets the above definition of an abandonment.

As is the case with either a disposal via sale or abandonment, the remaining (or adjusted) tax basis of an asset is conceptually inseparable from the disposal loss deduction. Similarly, the remaining (or adjusted) tax basis of an asset is conceptually inseparable from tax depreciation deductions.

Timing or Temporary Book versus Tax Differences

Generally Accepted Accounting Principles ("GAAP")[2] define temporary differences as follows:

ASC 740-10-20

Temporary Difference - A difference between the tax basis of an asset or liability computed pursuant to the requirements in Subtopic 740-10 for tax positions, and its reported amount in the financial statements that will result in taxable or deductible amounts in future years when the reported amount of the asset or liability is recovered or settled, respectively. Paragraph 740-10-25-20 cites examples of temporary differences. Some temporary differences cannot be identified with a particular asset or liability for financial reporting (see ASC 740-10-05-10 and ASC 740-10-25-24 through 25-25), but those temporary differences do meet both of the following conditions:

a. Result from events that have been recognized in the financial statements.

b. Will result in taxable or deductible amounts in future years based on provisions of the tax law.

[2] References to GAAP in this section were obtained from ASC 740: Income Taxes

Reductions in the tax basis of an asset via depreciation or disposal loss deductions are temporary differences. GAAP provides the following example of a temporary difference further guidance that authoritatively demonstrates this point:

> d. Expenses or losses that are deductible before they are recognized in financial income. The cost of an asset (for example, depreciable personal property) may have been deducted for tax purposes faster than it was depreciated for financial reporting. Amounts received upon future recovery of the amount of the asset for financial reporting will exceed the remaining tax basis of the asset, and the excess will be taxable when the asset is recovered.

> **740-10-25-21** The examples in (a) through (d) in paragraph 740-10-25-20 illustrate revenues, expenses, gains, or losses that are included in taxable income of an earlier or later year than the year in which they are recognized in pretax financial income. Those differences between taxable income and pretax financial income also create differences (sometimes accumulating over more than one year) between the tax basis of an asset or liability and its reported amount in the financial statements. The examples in (e) through (i) in paragraph 740-10-25-20 illustrate other events that create differences between the tax basis of an asset or liability and its reported amount in the financial statements. For all of the examples, the differences result in taxable or deductible amounts when the reported amount of an asset or liability in the financial statements is recovered or settled, respectively.

Accumulated Deferred Income Taxes ("ADIT")

ADIT is comprised of deferred tax assets and liabilities that are recorded on a company's balance sheet. Deferred tax assets offset or reduce future tax payments, while deferred tax liabilities are amounts owed to the IRS in future periods. ADIT is generally calculated as the difference in book basis and tax basis of an asset multiplied by the applicable tax rate. Notably, the reducing tax basis *is* the tax deduction. ADIT is based on the tax deduction in comparison to the book value of the asset but ADIT is not the tax deduction or an amount to be paid back to customers. The most common component of ADIT for a regulated utility is deferred tax liabilities resulting from accelerated tax depreciation (or other reductions in tax basis such as abandonment, disposal, retirement, or impairment losses), as compared to book depreciation. For most assets, companies recognize depreciation ratably over the life of an asset when calculating and reporting net income for financial reporting ("book") purposes. However, the federal tax code allows companies to calculate taxable income in a manner that recognizes the depreciation expense associated with investment in that asset much sooner – on an accelerated basis. This effectively reduces that company's net income used to calculate income taxes, and therefore tax expense, early in the life of an asset relative to what it would be if based on net income used for financial reporting purposes that did not accelerate that depreciation expense. However, later in the life of the asset, when the company is still recognizing book depreciation expense (ratably) and the asset has been fully depreciated for tax purposes, the company's taxes due to the taxing authority in that period are higher than they would be if based on book income. This higher tax amount due later in the life of an asset is the payment of the taxes that were avoided earlier in the life of the asset through the recognition of accelerated tax depreciation. Hence the description as deferred taxes. But it is critical for this discussion to note that accelerated depreciation does nothing to change the *total tax payments* due from a company to the IRS over an asset's life. It only can and does impact the *timing* of tax payments – it defers them from early in the asset life to later in the asset life. When an asset is retired earlier than anticipated, and therefore prior to being fully depreciated, a deferred tax balance may still exist at the point of retirement – meaning the company in question has not paid all of the taxes that will be due to the IRS. However, those taxes will still come due when the remaining net book value of the asset in question reduces the company's net income, as it eventually must.

The follow excerpt from GAAP authoritatively demonstrates that temporary differences do not reduce total tax payments[3]:

> **740-10-25-28** A contention that those temporary differences will never result in taxable amounts, however, would contradict the accounting assumption inherent in the statement of financial position that the reported amounts of assets and liabilities will be recovered and settled, respectively; thereby making that statement internally inconsistent. Because of that inherent accounting assumption, the only question is when, not whether, temporary differences will result in taxable amounts in future years.

Example – Calculation of ADIT

GAAP provides the following illustrative example: [4]

> **>> Example 10: Change in Timing of Deductibility**
>
> **740-10-55-113** This Example demonstrates an application of the measurement requirements of paragraph 740-10-30-7 for a tax position that meets the paragraph 740-10-25-6 requirements for recognition. Measurement in this Example is based on a change in timing of deductibility.
>
> **740-10-55-114** In 20X1 an entity took a tax position in which it amortizes the cost of an acquired asset on a straight-line basis over three years, while the amortization period for financial reporting purposes is seven years. After one year, the entity has deducted one-third of the cost of the asset in its income tax return and one-seventh of the cost in the financial statements and, consequently, has a deferred tax liability for the difference between the financial reporting and tax bases of the asset.
>
> **740-10-55-115** In accordance with the requirements of this Subtopic, the entity evaluates the tax position as of the reporting date of the financial statements. In 20X2, the entity determines that it is still certain that the entire cost of the acquired asset is fully deductible, so the more-likely-than-not recognition threshold has been met according to paragraph 740-10-25-6. However, in 20X2, the entity now believes based on new information that the largest benefit that is greater than 50 percent likely of being realized upon settlement is straight-line amortization over 7 years.
>
> **740-10-55-116** In this Example, the entity would recognize a liability for unrecognized tax benefits based on the difference between the three- and seven-year amortization. In 20X2, no deferred tax liability should be recognized, as there is no longer a temporary difference between the financial statement carrying value of the asset and the tax basis of the asset based on this Subtopic's measurement requirements for tax positions. Additionally, the entity should evaluate the need to accrue interest and penalties, if applicable under the tax law.

Of particular note in this example is the requirement to compare the book basis in an asset to the tax basis in an asset to calculate ADIT each period. This example also demonstrates when and how the respective bases in an asset converge and that when they do, ADIT is reduced to zero. Finally, this example demonstrates that analysis and decisions that occur during the life of an asset (in this example an extension of the tax "life" of the asset) change the tax basis in an asset, which results in a change to ADIT. While in this example ADIT is reduced to zero as a result of an extension of the tax "life", the opposite is also true that the tax basis would reduce to zero and ADIT would increase if the remaining tax life is suddenly reduced to zero, as is the case when an asset is retired.

Interpretive accounting guidance further spells out the theory and steps associated with accounting for deferred income taxes as follows:[5]

[3] ASC 740 Income Taxes
[4] ASC 740 Income Taxes
[5] PricewaterhouseCoopers, LLP Income Tax Guide.

The tax provision for a given year as computed under ASC 740 represents not only the amounts currently due, but also the change in the cumulative future tax consequences of items that have been reported for financial reporting purposes in one year and taxable income purposes in another year (i.e., deferred tax). Under ASC 740, the current and deferred tax amounts are computed separately, and the sum of the two equals the total provision. The total tax expense is meant to match the components of pretax income with their related tax effects in the same year, regardless of when the amounts are actually reported on a tax return. Therefore, it is necessary to determine which filing positions a reporting entity would take based on information available at the time the provision is calculated.

In ASC 740, the computation of the tax provision focuses on the balance sheet. A temporary difference is created when an item has been treated differently for financial reporting purposes and for tax purposes in the same period, and when it is expected to reverse in a future period and create a tax consequence. The tax effect of these differences, referred to as deferred taxes, should be accounted for in the intervening periods. A deferred tax asset or liability is computed based on the difference between the book basis for financial reporting purposes and the tax basis of the asset or liability.

This asset and liability method, required by ASC 740, measures the deferred tax liability or asset that is implicit in the balance sheet; it is assumed that assets will be realized, and liabilities will be settled at their carrying amounts. If the carrying amounts of assets and liabilities differ from their tax bases, implicit future tax effects will result from reversals of the book-and tax-basis differences.

The basic ASC 740 model is applied through the completion of the following five steps:

Step 1: Identify temporary differences. There are two categories of temporary differences: (1) taxable temporary differences that will generate future tax (i.e., deferred tax liabilities) and (2) deductible temporary differences that will reduce future tax (i.e., deferred tax assets). Temporary differences are most commonly identified and quantified by (1) preparing a tax balance sheet and comparing it with the financial statement balance sheet and (2) reviewing the reconciliation of book income with taxable income.

Step 2: Identify tax loss carryforwards and tax credits. A reporting entity may have US federal, state and local, and foreign tax loss carryforwards and certain tax credits. Tax loss carryforwards typically include net operating losses (NOLs) and capital losses, which, depending on the relevant jurisdiction's applicable tax law, may be carried back to prior periods and/or forward to future periods to offset taxable income. Tax credits may include research and development credit (R&D credit), foreign tax credits, the US federal corporate alternative minimum tax credit (CAMT credit), investment tax credits, and other tax credits. Tax credits generally provide a "dollar-for-dollar" benefit against taxes payable.

Step 3: Determine the tax rate to apply to temporary differences and loss carryforwards. The applicable tax rate is the rate, based on enacted tax law, that will be in effect in the period in which temporary differences reverse or are settled. TX 4.3 discusses several factors that should be considered in determining the applicable rate.

Step 4: Calculate deferred tax assets and liabilities. For gross temporary differences and tax loss carryforwards, this entails multiplying the gross balance by the applicable tax rate. Tax credits generally provide a "dollar-for-dollar" benefit and therefore are already tax-effected.

Step 5: Evaluate the need for a valuation allowance. Under ASC 740, deferred tax assets resulting from deductible temporary differences, loss carryforwards, and tax credit carryforwards must be recorded, and then subjected to a test for realizability. A valuation allowance must be established for deferred tax assets if it is "more-likely-than-not" that they will not be realized. TX 5 discusses the valuation allowance assessment in detail.

Traditional Ratemaking and the Normalization Method of Accounting for Income Taxes

First, utility revenue requirements reflect income tax expenses at the statutory rate applied to book net income before taxes, rather than basing the revenue requirement on its actual current period tax payments (i.e., the utility revenue requirement is calculated based on an income tax expense associated with the level of income determined using book depreciation rates – not accelerated tax depreciation). Reflecting income taxes in rates based on actual current period tax payments would result in a violation of the IRS' normalization rules,[6] which would have significant negative consequences for the Company and for its customers. By reflecting income tax expense in the

[6] A requirement spelled out in the federal tax code that dictates the regulatory treatment of plant-related ADIT and associated penalty for violation of the requirements.

revenue requirement at the statutory rate applied to adjusted book net income rather than taxable income, utility ratemaking results in customers effectively providing the funds the utility needs to pay its current and net deferred tax liabilities (ADIT) to the IRS. Said another way, customers pay rates as if the taxes were not being deferred. The revenues that are collected from customers that are related to deferred taxes, which the utility will not pay until some later date, become cash available to the utility to invest in its system until the time when those deferred taxes come due for payment to the IRS. In this way, deferred tax liabilities collected from customers can be thought of as an interest free loan from the IRS, because the cash available to the utility offsets the need to use other forms of financing to acquire that cash – financing that would obviously have a cost of capital associated with it. Customers are compensated for the long-term use of their funds through a rate base reduction which lowers their rates; i.e., the annual general rate revenue requirement is reduced by the product of the ADIT rate base reduction multiplied by the Company's WACC. The reduction of rate base for deferred tax liabilities is an acknowledgement that the utility has collected amounts from customers that will not be paid to the IRS until future periods – amounts which therefore reduce the amount of the Company's investment in rate base that must be financed by traditional debt and equity forms of financing. This lower rate base level results in a lower revenue requirement used to set customer general rates. That lower annual general rate revenue requirement is the benefit customers receive from ADIT.[7]

Example - Traditional Ratemaking and the Normalization Method

Schedule MJL-R3 provides a simplified example of how ADIT is treated for traditional ratemaking over a 20-year period using a hypothetical investment of $1,000 on lines one through 15. Through this example, one can observe the life cycle of ADIT associated with an isolated asset. This example demonstrates what I briefly described earlier – that income taxes paid by the utility change in their timing because of ADIT,[8] but do not change in the total amount of taxes ultimately paid.

In this example, accelerated tax depreciation as compared to book depreciation results in a deferred tax liability, which, as I described earlier, is the most common component of ADIT for the Company or any utility. Lines one through three indicate a $1,000 investment in year one, the accumulation of $50 of book depreciation in the reserve for depreciation each year over the 20-year period, and the resulting net plant balance. Lines four through eight is the calculation of ADIT by year.[9] This demonstrates the effect of accelerated tax depreciation, which reduced taxable income early in the asset life, allowing the utility to avoid the payment of taxes until the time that book depreciation "catches up" with the accelerated tax depreciation that is allowed by the federal tax code. ADIT must ALWAYS equal zero at the end of the life of an investment because both the book basis and tax basis must equal zero at that time – meaning all of the investment has eventually been expensed both for tax purposes and book purposes – and there is no remaining ADIT when the book and tax basis converge at zero. Note this effect in line 8 of the example, where ADIT becomes zero in year 21. Line 9 – Rate Base is the net plant investment on line three less ADIT – since the ADIT provided cash that displaced the need for traditional financing of that amount of rate base for a period of time - on line 8, which is the proper treatment of ADIT for traditional ratemaking as I discussed previously. Lines 11 through 15 is a summation of the revenue

[7] Net deferred tax liabilities in particular.

[8] Particularly the tax deductions (in the case of accelerated depreciation) that result in book-tax differences and produce ADIT.

[9] The difference between the book basis of the asset and tax basis multiplied by the applicable tax rate.

requirement by year. Of note, income tax expense on line 14 is included in the revenue requirement at the statutory rate as I described is the proper treatment for traditional ratemaking previously (the 25% statutory tax rate on line 7 has been applied to the return on rate base on line 11).[10]

Schedule MJL-R3 further demonstrates the calculation of a tax return, including the impacts on current and deferred income tax liabilities and expenses. Line 16 identifies Net Income Before Income Tax ("NIBIT"), which is the summation of the return on rate base from line 11 and income taxes on line 14.[11] Line 18 is the change in cumulative tax timing differences in the current period, i.e., this is the difference in book income and taxable income in the current period that results from adding book depreciation back to NIBIT, while subtracting tax depreciation from NIBIT. The result becomes net income as adjusted for (accelerated) tax depreciation and given this example produces taxable income on line 19. Taxable income is multiplied by the tax rate to produce line 20, which are the tax payments owed to the IRS in each current period. Line 21 provides the annual activity for deferred tax expense and deferred tax liabilities, as calculated above in the revenue requirement.[12] Total income tax expense on line 22 equals income taxes included in the revenue requirement on line 14 in each period – this demonstrates that the taxes reflected in the revenue requirement are equal to the taxes due in the period along with the taxes deferred in the period – those deferred taxes being a temporary source of cash to the utility. Note that the summation of current tax expense on line 20 is $201 over the 20-year period and equals the summation of income taxes included in the revenue requirement over that same 20-year period. This part of the example evidences that, although greater income tax amounts were included in the revenue requirement than paid to the IRS earlier in the 20-year period, ultimately the total income tax cost included in the revenue requirement (both the current and deferred or ADIT elements of tax expense) is paid to the IRS.

[10] Ignoring any interest deduction for ease of illustration.
[11] Presuming all other costs included in the revenue requirement are recovered dollar for dollar with no resulting contribution to net income.
[12] The year over year change in ADIT from line 8.

AMEREN MISSOURI
UTILITY INCOME TAX EXAMPLE
ER-2024-0319

Line		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	Total
Traditional Ratemaking Revenue Requirement:																							
1	Original Cost of Plant	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	
2	Depreciation Reserve	-	50.00	100.00	150.00	200.00	250.00	300.00	350.00	400.00	450.00	500.00	550.00	600.00	650.00	700.00	750.00	800.00	850.00	900.00	950.00	1,000.00	
3	Net Plant	1,000.00	950.00	900.00	850.00	800.00	750.00	700.00	650.00	600.00	550.00	500.00	450.00	400.00	350.00	300.00	250.00	200.00	150.00	100.00	50.00	-	
4	Book Basis	1,000.00	950.00	900.00	850.00	800.00	750.00	700.00	650.00	600.00	550.00	500.00	450.00	400.00	350.00	300.00	250.00	200.00	150.00	100.00	50.00	-	
5	Tax Basis	1,000.00	800.00	600.00	400.00	200.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6	Cumulative Tax Timing Difference	-	150.00	300.00	450.00	600.00	750.00	700.00	650.00	600.00	550.00	500.00	450.00	400.00	350.00	300.00	250.00	200.00	150.00	100.00	50.00	-	
7	Tax Rate	25%																					
8	ADIT or Deferred Tax Liability	-	37.50	75.00	112.50	150.00	187.50	175.00	162.50	150.00	137.50	125.00	112.50	100.00	87.50	75.00	62.50	50.00	37.50	25.00	12.50	-	
9	Rate Base	1,000.00	912.50	825.00	737.50	650.00	562.50	525.00	487.50	450.00	412.50	375.00	337.50	300.00	262.50	225.00	187.50	150.00	112.50	75.00	37.50	-	
10	WACC	7%																					
11	Return on Rate Base	70.00	63.88	57.75	51.63	45.50	39.38	36.75	34.13	31.50	28.88	26.25	23.63	21.00	18.38	15.75	13.13	10.50	7.88	5.25	2.63	-	603.75
12	O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Depreciation	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	-	1,000.00
14	Income Taxes	23.33	21.29	19.25	17.21	15.17	13.13	12.25	11.38	10.50	9.63	8.75	7.88	7.00	6.13	5.25	4.38	3.50	2.63	1.75	0.88	-	201.25
15	Total Revenue Requirement	143.33	135.17	127.00	118.83	110.67	102.50	99.00	95.50	92.00	88.50	85.00	81.50	78.00	74.50	71.00	67.50	64.00	60.50	57.00	53.50	-	1,805.00
Income Tax Provision:																							
16	Net Income Before Income Tax	93.33	85.17	77.00	68.83	60.67	52.50	49.00	45.50	42.00	38.50	35.00	31.50	28.00	24.50	21.00	17.50	14.00	10.50	7.00	3.50	-	805.00
17	Permanent Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Temporary Differences	(150.00)	(150.00)	(150.00)	(150.00)	(150.00)	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	-	-
19	Taxable Income	(56.67)	(64.83)	(73.00)	(81.17)	(89.33)	102.50	99.00	95.50	92.00	88.50	85.00	81.50	78.00	74.50	71.00	67.50	64.00	60.50	57.00	53.50	-	805.00
20	Current Tax Payable / Expense	(14.17)	(16.21)	(18.25)	(20.29)	(22.33)	25.63	24.75	23.88	23.00	22.13	21.25	20.38	19.50	18.63	17.75	16.88	16.00	15.13	14.25	13.38	-	201.25
21	Deferred Tax Liability / Expense	37.50	37.50	37.50	37.50	37.50	(12.50)	(12.50)	(12.50)	(12.50)	(12.50)	(12.50)	(12.50)	(12.50)	(12.50)	(12.50)	(12.50)	(12.50)	(12.50)	(12.50)	(12.50)	-	-
22	Total Income Tax Expense	23.33	21.29	19.25	17.21	15.17	13.13	12.25	11.38	10.50	9.63	8.75	7.88	7.00	6.13	5.25	4.38	3.50	2.63	1.75	0.88	-	201.25
Analysis of Cash Flows by Stakeholder:																							
23	Company	(842.50)	151.38	145.25	139.13	133.00	76.88	74.25	71.63	69.00	66.38	63.75	61.13	58.50	55.88	53.25	50.63	48.00	45.38	42.75	40.13	-	603.75
24	Customers	(143.33)	(135.17)	(127.00)	(118.83)	(110.67)	(102.50)	(99.00)	(95.50)	(92.00)	(88.50)	(85.00)	(81.50)	(78.00)	(74.50)	(71.00)	(67.50)	(64.00)	(60.50)	(57.00)	(53.50)	-	(1,805.00)
25	IRS	(14.17)	(16.21)	(18.25)	(20.29)	(22.33)	25.63	24.75	23.88	23.00	22.13	21.25	20.38	19.50	18.63	17.75	16.88	16.00	15.13	14.25	13.38	-	201.25
26	Construction Crews	1,000.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,000.00
27	Check	-	0.00	0.00	(0.00)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Schedule MJL-R3

Schedule MJL-S1

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF MITCHELL LANSFORD

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

Mitchell Lansford, being first duly sworn states:

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

/s/ Mitchell Lansford
Mitchell Lansford

Sworn to me this 17th day of January, 2025.

Schedule MJL-S1

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a	)	
Ameren Missouri's Tariffs to Adjust Its	)	File No.: GR-2024-0369
Revenues for Natural Gas Service.	)	

AFFIDAVIT OF MITCHELL LANSFORD

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

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

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

/s/ Mitchell Lansford
Mitchell Lansford

Sworn to me this 2nd day of May, 2025.