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Before the Public Service Commission
of the State of Missouri

Direct Testimony

of

John J. Reed

on behalf of

The Empire District Electric Company d/b/a Liberty

November 6, 2024

Liberty™

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THE EMPIRE DISTRICT ELECTRIC COMPANY D/B/A LIBERTY
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION
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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John J. Reed. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. By whom are you employed and in what capacity?

A. I am the Chairman of Concentric Energy Advisors, Inc. ("Concentric").

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of The Empire District Electric Company d/b/a Liberty ("Liberty" or the "Company").

Q. Please describe your educational and professional background.

A. I have more than 47 years of experience in the energy industry and have worked as an executive in, and consultant and economist to, the energy industry. Over the past 36 years, I have directed the energy consulting services of Concentric, Navigant Consulting, and Reed Consulting Group. I have served as Vice Chairman and Co-CEO of the nation's largest publicly-traded consulting firm and as Chief Economist for the nation's largest gas utility. I have provided regulatory policy and regulatory economics support to more than 100 energy and utility clients and have provided expert testimony on regulatory, economic, and financial matters on more than 200 occasions before the Federal Energy Regulatory Commission ("FERC"), state utility regulatory agencies, Canadian regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. My background and list of prior testimony is presented in more detail in **Direct Schedule JJR-1**.

Q. Have you previously testified before the Missouri Public Service Commission ("Commission") or any other regulatory agency?

A. Yes. I have testified on behalf of Liberty before this Commission previously, and I have appeared for other clients in Missouri on many other occasions, most recently on fuel adjustment mechanism and resource planning prudence matters. My prior testimony in Missouri is detailed below.

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Missouri Gas Energy	1/03 4/03	Missouri Gas Energy	GR-2001-382	Gas Purchasing Practices, Prudence
Aquila Networks	2/04	Aquila-MPS, Aquila L&P	ER-2004-0034 HR-2004-0024	Cost of Capital, Capital Structure
Aquila Networks	2/04	Aquila-MPS, Aquila L&P	GR-2004-0072	Cost of Capital, Capital Structure
Missouri Gas Energy	11/05 2/06 7/06	Missouri Gas Energy	GR-2002-348 GR-2003-0330	Capacity Planning
Missouri Gas Energy	11/10 1/11	KCP&L	ER-2010-0355	Natural Gas DSM
Missouri Gas Energy	11/10 1/11	KCP&L GMO	ER-2010-0356	Natural Gas DSM
Laclede Gas Company	5/11	Laclede Gas Company	CG-2011-0098	Affiliate Pricing Standards
Union Electric Company d/b/a Ameren Missouri	2/12 8/12	Union Electric Company	ER-2012-0166	Return on Equity, Earnings Attrition, Regulatory Lag
Union Electric Company d/b/a Ameren Missouri	6/14	Noranda Aluminum Inc.	EC-2014-0223	Ratemaking, Regulatory and Economic Policy
Union Electric Company d/b/a Ameren Missouri	1/15 2/15	Union Electric Company	ER-2014-0258	Revenue Requirements, Ratemaking Policies
Great Plains Energy Kansas City Power and Light Company	8/17 2/18 3/18	Great Plains Energy, Kansas City Power & Light Company, and Westar Energy	EM-2018-0012	Merger Standards, Transaction Value, Merger Benefits, Ring-Fencing,
Union Electric Company d/b/a Ameren Missouri	6/19	Union Electric Company d/b/a Ameren Missouri	EO-2017-0176	Affiliate Transactions, Cost Allocation Manual
Union Electric Company d/b/a Ameren Missouri	7/19 1/20 2/20	Union Electric Company d/b/a Ameren Missouri	ER-2019-0335	Reasonableness of Affiliate Services and Costs
Union Electric Company d/b/a Ameren Missouri	3/21	Union Electric Company d/b/a Ameren Missouri	GR-2021-0241	Affiliate Transactions
Union Electric Company d/b/a Ameren Missouri	3/21 10/21	Union Electric Company d/b/a Ameren Missouri	ER-2021-0240	Affiliate Transactions, Prudence Standard, Used and Useful Principle
Empire District Electric Company	5/21 12/21 1/22	Empire District Electric Company	ER-2021-0312	Return on Equity
Empire District Gas Company	8/21 3/22	Empire District Gas Company	GR-2021-0320	Return on Equity
Empire District Electric Company	5/22	Empire District Electric Company	EO-2022-0040; EO-2022-0193	Prudence and Carrying Costs
Evergy Missouri West	7/22	Evergy Missouri West	EF-2022-0155	Prudence, Carrying Costs and Discount Rate

Evergy Missouri West and Evergy Missouri Metro	11/23 12/23 1/24	Evergy Missouri West and Evergy Missouri Metro	EO-2023-0276; EO-2023-0277	FAC Prudence Audit
Ameren Missouri	11/23 3/24	Ameren Missouri	EF-2024-0021	Prudence Standard, Securitization

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to recommend the Commission discontinue the sharing mechanism in the Company's currently authorized Fuel Adjustment Clause ("FAC") mechanism. In support of this recommendation, I address the issue of the incentives embedded within the FAC rate schedules. I also address the inclusion of transmission cost recovery through the FAC mechanism.

My testimony raises the question of whether the continuation of the FAC sharing provision, at least as it is now structured, is consistent with good regulatory policy and practice, and when and where incentives are useful in ratemaking. In addressing this concern my testimony will consider two basic threshold questions with regard to the Company's FAC: 1) how should incentives be applied in the FAC, if at all, and 2) which costs should appropriately be subject to incentives? Lastly, I will provide discussion of the broader U.S. experience with FAC mechanisms.

III. FAC SHARING PROVISIONS

Q. Are fuel adjustment clauses common in U.S. utility ratemaking?

A. Yes. Nearly every state in the United States has some form of energy cost recovery mechanism for regulated utilities. These adjustment clauses are designed to align the costs associated with purchasing fuel to generate electricity, or purchased power agreement ("PPA") costs, with the rates that are charged to customers. Typically, adjustments to FAC rates are made periodically, often monthly or quarterly, and are based on actual fuel and purchased power expenses incurred by the utility. By incorporating fuel adjustment clauses into rate structures, regulators promote transparency and stability in rates, allowing for timely adjustments to reflect fluctuations in fuel prices (which may be large, volatile, unpredictable, and beyond the control of the utility) while minimizing the financial impact on both customers and the company. FAC mechanisms help to strengthen the tie between the rates that customers pay and the costs incurred to serve those customers.

Q. To what expenses do FAC mechanisms typically apply?

A. FAC mechanisms for electric utilities primarily apply to fuel, purchased power, and transmission expenses. However, these expenses are typically addressed outside of base rate proceedings because as mentioned above they are less stable, more unpredictable, and largely outside of the utility's management control, which are the criteria for distinguishing these costs from those addressed through base rate proceedings.

Q. What are incentive mechanisms, and are they commonly included in utility ratemaking?

A. Incentive mechanisms in utility regulation are frameworks designed to encourage utilities to improve performance, enhance efficiency, or achieve specific policy objectives. These mechanisms often involve financial rewards or penalties linked to the utility's ability to meet predefined targets or standards, such as reducing energy consumption, increasing renewable energy generation, or improving service reliability. Common incentive mechanisms include performance-based incentive mechanisms, where utilities are rewarded for achieving specified goals within their control and are measured against a baseline target. Other incentive mechanisms include revenue sharing arrangements, where utilities share cost savings or revenues with customers, and performance benchmarking, which compares a utility's performance to industry standards or best practices. These mechanisms aim to align the interests of utilities and customers, fostering innovation, investment in infrastructure, and the advancement of policy goals.

Q. To which expenses or activities do incentive mechanisms typically apply?

A. Incentive mechanisms in utility ratemaking typically apply to costs or activities within the control of the utility. Incentive mechanisms that are program-based rather than cost-based apply to activities, conduct, or programs within the control of the utility. Incentive mechanisms only make sense where management behavior can materially affect performance. One would not reasonably apply incentive mechanisms to costs or revenues that are based largely on items outside of management's control such as the weather, compliance with laws (e.g., taxes), macroeconomic conditions (e.g., inflation), and established accounting practices (e.g., depreciation).

Q. What is the intersection between fuel adjustment clauses and incentive mechanisms?

A. The intersection is and should be very limited. First, fuel adjustment clauses are utilized for costs that are large, volatile, and not within the control of the utility company. Second, incentive mechanisms properly apply to costs or conduct that is within the control of the utility in an effort to promote efficiency or enhanced performance. However, there may be instances where an overlap might occur, such as off-system sales ("OSS"), which I will discuss later in my testimony.

Q. Should incentive mechanisms or automatic sharing mechanisms be included in fuel cost recovery clauses?

A. No. Incentive mechanisms as they relate to fuel cost recovery clauses should be limited because they are contrary to the purpose of FACs and can create perverse incentives. Additionally, sharing mechanisms do not serve as a substitute for or enhance Commission oversight.

First, if fuel expenses were easily predictable and not subject to significant variation, there would be no need for FACs. It is precisely because utilities' fuel and power costs are large, unpredictable, and volatile that FACs are a required ratemaking tool. For this reason, automatic sharing mechanisms are incongruous with FACs; the utility and its customers are either being penalized or receiving undue windfalls for fluctuations in costs that are beyond the utility's control.

Second, embedding an automatic sharing mechanism in a utility's FAC creates a perverse incentive for the utility to seek the highest level of base fuel cost possible, even if only to avoid a fuel cost penalty that generally is outside the utility's control.

Finally, an automatic sharing mechanism is not a substitute for Commission oversight. An automatic sharing mechanism does not reduce the regulatory burden, does not eliminate the Commission's duty to review fuel adjustment clause filings and the utility's prudence, and does not create any actual incentives in a way that systematically benefits a utility or its customers.

Q. What is the overlap between fuel adjustment clauses and incentives with respect to OSS?

A. For vertically integrated electric utilities, OSS refers to the practice of a utility that controls its generation selling its excess electric energy, capacity, or attributes (e.g., RECs) to entities outside of its regulated service territory or customer base. Prior to the development of organized markets like the Southwest Power Pool ("SPP"), electric utilities dispatched generation to meet on-system loads and contractual commitments, and they maintained power marketing functions to optimize the use of generation through off-system transactions. These off-system purchases and sales took advantage of generation surpluses and shortfalls and load diversity, and they sought to have the most efficient generator operate to meet load regardless of which utility controlled that generator. OSS in regulated, non-organized markets are typically subject to regulatory oversight to ensure fairness and protect the interests of customers. OSS in non-organized markets can provide additional revenue for the utility, potentially leading to benefits such as reduced costs for customers or increased investment in infrastructure. In that form of markets, those activities have often been captured within FACs and been subjected to revenue sharing or other incentives because management performance in seeking out and capturing off-system value has a significant impact on the benefits derived from these activities. As discussed later in this testimony, the concept of OSS in an organized generation market is an artifact of the pre-organized markets like SPP since a utility no longer dispatches to meet on-system load, although the language of some FACs has not been updated to reflect the new wholesale market regime.

Q. Please describe your understanding of Liberty's current FAC.

A. There are two separate processes for Liberty's framework for ratemaking: (1) "base" rate proceedings; and (2) the use of adjustment clauses. First, Liberty undergoes periodic reviews of its "base" cost of service through base rate reviews. Apart from the costs examined through base rate proceedings, certain changes in costs are recovered through specific rate adjustment mechanisms, including fuel, purchased power, and transmission costs.

The Company's FAC tariff requires Liberty to make periodic FAC filings to review the Company's actual energy costs. These filings allow the Commission and the Company to adjust FAC rates based on a comparison of energy costs included in base rates to the actual energy costs the Company incurs to provide electric service to its Missouri customers.

The Company's base rates are often reset multiple years apart during general rate cases. Therefore, the cost of fuel included in base rates and to which the fuel rate is compared often does not reflect then-current market conditions or wholesale market operations.

Q. Describe your understanding of the mechanics of Liberty's FAC.

A. Liberty's FAC accumulates the Company's Total Energy Cost ("TEC"), defined generally as variable fuel, purchased power, eligible transmission expense, and net emissions costs, less OSS revenue and renewable energy credit revenue. These costs accumulate during six-month accumulation periods. Each six-month accumulation period is followed by a six-month recovery period ("RP") during which ninety-five percent (95%) of the over- or under-recovery of TEC during the previous six-month accumulation period relative to the amount in base rates is returned to or collected from customers. As further explained below, the remaining 5% of the cost differential is "shared" by the utility. The 95% of cost changes charged to customers is implemented through either a decrease or an increase of the FAC per kWh rate. Because the total amount charged through the FAC will rarely, if ever, match the actual costs, Liberty's FAC is designed to true-up the difference between the revenues billed and the revenues authorized for collection during recovery periods, including interest at Liberty's short-term interest rate.

Liberty is also subject to periodic FAC prudence audits by the Commission and its Staff. Any disallowance the Commission orders as a result of a FAC prudence review would include interest at Liberty's short-term interest rate and would be accounted for as an adjustment item when calculating the per kWh rate for a future recovery period.

Q. You note that Liberty's FAC includes a 95%-5% ("95/5") sharing provision. Please describe that provision in more detail.

A. Liberty's FAC includes a 95/5 sharing mechanism by which the Company passes on 95% of over- or under-recoveries to its customers. If actual total energy costs exceed the base rate amount, Liberty recovers 95% of the difference through the FAC and absorbs 5%. If actual fuel costs drop below the amount in base rates, Liberty's FAC credits customers with 95% of the difference and retains 5% for the utility.

Q. Why did the Commission include this sharing mechanism in Liberty's FAC?

A. I understand the Commission included this 95/5 sharing mechanism in Liberty's FAC as a response to Missouri Statute RSMo. §386.266, *Rate schedules for interim energy charges or periodic rate adjustment* (the "FAC statute" or the "statute"). The statute states that "[t]he commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities."[1] The Commission promulgated rules to govern the provision of FACs beginning in 2006, eventually culminating in rule 20 CSR 4240-20.090.[2] I understand the Commission intended the sharing provision to represent an incentive

[1] RSMo. §386.266(1).
[2] https://www.sos.mo.gov/CMSImages/AdRules/csr/current/20csr/20c4240-20A.pdf.

for the Company to operate efficiently in its fuel and purchased power procurement activities, thereby presumably providing benefits to customers.

Q. Why is it important that incentives align with benefits to customers?

A. The sharing provision should represent an incentive to control costs that are within the Company's control and provide the benefits of that cost control primarily to customers and partially to the Company. Good regulatory policy ensures the alignment of costs and benefits. If there is no such alignment because costs are disallowed for recovery based on factors that are outside the control of the utility, then misalignment becomes a threat to the reasonableness of rates. Furthermore, the ability to only partially recover prudently incurred costs for which the customer is concurrently receiving full benefits represents a misalignment between the duty to serve and the opportunity to earn a fair return on investment.

Q. Does the FAC statute specifically call for sharing?

A. No, nothing in the statutes requires the Commission or the Company to include a sharing provision in the FAC. However, what is required in the statute is a finding by the Commission that the adjustment mechanism "is reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity."[3]

Q. Do the Commission rules governing FAC mechanisms (20 CSR 4240-20.090) specifically call for sharing?

A. No. The rule is not prescriptive with regards to the incentives to improve the efficiency and cost-effectiveness of fuel and purchased-power procurement activities, and it

[3] Missouri Statute 386.266, 5. (1).

states, "[A]ny incentive mechanism or performance-based program shall be structured to align the interests of the electric utility's customers and shareholders."[4]

Q. How did the Commission first establish the FAC sharing provision?

A. As the Office of the Public Counsel ("OPC") has detailed in other proceedings,[5] in its development of initial FAC rules in docket EX-2006-0472 and again in docket EX-2016-0294, the Commission discussed a number of issues with stakeholders, including the State's utilities, consumer groups, OPC, and Staff. Of importance was the Commission's commitment to protecting the utilities' opportunity to earn a fair return.[6] The Commission first authorized an FAC for Aquila in 2007 in Docket No. ER-2007-0004.

Q. How did the Commission establish the first FAC for the Company?

A. In the Commission's Order in Docket No. ER-2008-0093, Liberty (then The Empire District Electric Company) was granted its first fuel adjustment clause, which included the 95/5 sharing mechanism that is in place today. In its decision, the Commission emphasized that while the statute does not provide specific guidance on when a fuel adjustment clause should be approved, it must reasonably be designed to provide the utility with a sufficient opportunity to earn a fair return on equity.[7] In granting the FAC, it determined that Liberty's situation met the three pronged test for determining whether a fuel adjustment clause was appropriate for the Company's fuel and purchased power costs. That three pronged test asked if 1) the costs were a substantial portion of the Company's costs, 2) the costs were variable and could rapidly eat up the

[4] 20 CSR 4240-20.090 14(B).
[5] Direct Testimony of Lena Mantle, Exhibit LMM-D-2, Docket No. EO-2023-0276/0277.
[6] *See for example,* Report and Order ER-2008-0093, July 30, 2008.
[7] Report and Order ER-2008-0093, July 30, 2008, p. 35.

returns the Company might otherwise earn, and 3) large portions of the costs were beyond the control of the Company. The Commission concluded that given the market conditions in place at the time, "[I]t would be impossible for Empire to earn its Commission allowed return on equity without a fuel adjustment clause."[8]

Q. How did the Commission establish the 95/5 sharing provision in Liberty's first FAC?

A. The Commission concluded that a prudence review is necessarily limited by the availability of people with the time and training to devote to a detailed examination of actions related to fuel and purchased power expenses. Instead, a 95/5 sharing provision would protect customers by giving Liberty an incentive to be prudent in its decision making.[9]

Q. Do you believe the sharing provision, as originally structured, continues to be appropriate to include in the Company's FAC?

A. No. While I understand the Commission's rationale for the inclusion of an FAC incentive mechanism in 2008, i.e., before the implementation of a centrally dispatched wholesale electric market, market dynamics have changed substantially and warrant the reconsideration of such a sharing provision. I believe that incentives should apply to costs that result from actions that are within the control of the Company. Nearly all of the costs included in the Company's current FAC are no longer within its control and should not be subject to sharing of either positive or negative cost differentials. The only exception to this general approach may be the direct procurement of fuel for generating plants, but even an incentive for this limited category of costs should be

[8] Report and Order ER-2008-0093, July 30, 2008, p. 39.
[9] Report and Order ER-2008-0093, July 30, 2008, pp. 44, 47.

structured much differently than it is in the current FAC and is probably better dealt with through prudence reviews that already take place for FAC costs and in base rate proceedings.

Q. How are prudence reviews handled under the current FAC methodology?

A. The current requirement for prudence reviews is that all costs subject to recovery through the FAC are to be reviewed at least every 18 months. This appropriately incentivizes the Company to effectively manage its fuel and purchased power procurement activities. These prudence audits can result in disallowances should the Commission determine the Company's conduct was imprudent given what was known or knowable when various resource planning decisions were made.

Q. Has the Commission previously opined about the sufficiency of prudence reviews in FAC mechanisms?

A. Yes, the Commission stated in Liberty's first FAC approval that "an after-the-fact prudence review is not a substitute for an appropriate financial incentive."[10]

Q. Why is prudence an appropriate standard for recovery of FAC costs and why should it be revisited for Liberty's FAC at this time?

A. The most obvious changed circumstance that warrants a revision to the FAC is that the need for the efficiency incentive that the Commission wished to provide is now obviated due to the regional operation of the generation fleet by an independent system operator (SPP), replacing the utility's operation of the power resources it has in its portfolio. Again, consistent with the principle that incentives should apply to results that are within the utility's control, the 95/5 sharing mechanism no longer fits with that principle for the load served through SPP and related transmission expenses.

[10] Report and Order ER-2008-0093, July 30, 2008, p. 44.

Under traditional cost-based ratemaking, a utility is permitted to include prudently incurred costs in the revenue requirement used to set its rates. The standard for the evaluation of whether costs are prudently incurred is built on four features, all of which are familiar to the Commission. First, prudence relates to actions and decisions. Costs themselves are neither prudent nor imprudent. It is the decision or actions that led to cost incurrence that must be reviewed and assessed, not the results of those decisions. In other words, prudence is a measure of the quality of decision-making, and does not reflect how the decisions turned out. The second feature is a presumption of prudence, which is often referred to as a rebuttable presumption. The burden of showing that a decision is outside of reasonable bounds falls, at least initially, on the party challenging the utility's decisions. The third feature is the total exclusion of hindsight from a properly constructed prudence review. A utility's decisions must be judged based upon what was known or reasonably knowable at the time the decision was made by the utility. The final feature is that decisions being reviewed need to be compared to a range of reasonable behavior; prudence does not require perfection or achieving the lowest possible cost. This standard recognizes that reasonable people can differ and that there is a range of reasonable actions and decisions that is consistent with prudence. Simply put, a decision can only be labelled as imprudent if it can be shown that such a decision was outside the bounds of what a reasonable person would have done under those circumstances.

This approach is well established and expected by investors in providing a regulatory framework for balancing the interests of customers and utility investors. While it is not the only workable framework, it is the one which is in use in nearly every utility regulatory jurisdiction in North America. Utilities are typically not allowed to recover more than their actual costs when favorable results are achieved and are not asked to bear the results of what turned out to be unfavorable outcomes if the decisions leading to a result were reasonable. While there may be a desire to have the higher costs of unfortunate outcomes, including extraordinary weather occurrences, shared between customers and investors, that type of risk sharing is not appropriate when the utility operates under a cost-based regulatory regime with the acknowledged standard for cost recovery being the traditional prudence standard. Utilities are acutely aware of the need to act in a prudent manner to recover their costs, and regulators have proven to be highly capable in evaluating the prudence of utility decision making.

Q. Are the Commission's periodic prudence audits now a sufficient incentive for the Company to ensure that its FAC costs are just and reasonable?

A. Yes, based on the new market paradigm. Focusing on the remaining aspects of FAC costs that are within the utility's control, such as fuel procurement, prudence audits evaluate the actions, decisions, and circumstances that were in place at the time resource planning and procurement decisions were made. These resource planning decisions are within the Company's control, and therefore the review and audit of these decisions is a meaningful incentive to encourage the utility to procure long-term fuel and purchased power costs effectively, and to maximize the benefits derived from the fuel and generation portfolios. Stated simply, the risk of cost disallowance resulting from a Commission finding of imprudent decision-making is a fully sufficient incentive for utilities to engage in rational and prudent fuel procurement and other activities that remain within their control.

Q. Does the current FAC sharing mechanism provide any efficiency incentive to the Company?

A. No. As stated earlier, the underlying energy costs and revenues in the FAC are volatile, unpredictable and largely beyond the utility's control. It is therefore virtually impossible to estimate the amount of energy and transmission cost that should be included in base rates that are set as much as four years in advance of the costs actually being incurred. The estimation of costs to be incurred multiple years beyond the update period that is used to calculate base rates involves variables and forecasts that are far from the "known and measurable" standard for inclusion in customer rates. Therefore, differences between base rate cost levels and actual costs incurred years later have almost nothing to do with management performance. These differences relate to national and global fuel markets, the actions of numerous power market participants, federal and state renewable energy policies, environmental policies, economic growth, end-use customer choices, energy efficiency programs, and, significantly, the weather. Penalizing or rewarding management through cost sharing for cost differences driven by these forces will have no impact on management performance and provide no customer benefits.

Second, the sharing provision at least partially divorces rates from costs and can materially affect the Company's opportunity to earn a fair return on equity. This is contrary to a statutory requirement for FACs and weakens the Company's financial profile and its ability to attract the capital required to meet customers' needs at just and reasonable rates.

Third, the sharing mechanism currently used in the FAC places undue and unneeded importance on the estimate of fuel and purchase power costs included in base rates. It is important to remember that the reason the FAC exists in the first place is that these costs are unpredictable. The reason why any cost or category of costs is singled out for a cost tracker or an adjustment clause is because it is not in either the customers' or the utility's best interest to rely on base rate cases to adjust these cost levels. While OPC has made arguments about why an FAC "mutes" price signals (e.g., costs accumulate over several months, recovery periods follow the periods when actual costs are incurred, etc.),[11] the "muting" of price signals is not pertinent when the alternative is undercharging or overcharging customers for the costs that are incurred to serve them.

These costs are too significant to subject them to a multi-year guessing game, and the frequency of base rate changes should not have to be increased just to deal with unforeseeable changes in these costs. The need to file frequent rate cases just to avoid a mismatch in these costs and rates is clearly not efficient nor cost effective for customers.

Q. Are you aware of OPC Witness Lena Mantle's FAC testimony in Evergy Missouri West's ("EMW") ongoing proceeding in Docket ER-2024-0189?

A. Yes, I am aware that OPC Witness Mantle is proposing a 75/25 sharing mechanism in EMW's current rate case "as a result of resource planning decisions that have resulted in a dependence on spot market energy."[12]

Q. What are your reactions to OPC's FAC sharing proposal?

A. In my view, Ms. Mantle's recommendation is punitive rather than grounded in sound regulatory theory or principle. A sharing provision of 95/5, let alone one set at 75/25, is counter to the goals of regulatory efficiency and limits a utility's opportunity to earn a fair return. As I have outlined above, the underlying energy costs and revenues in the

[11] Docket No. ER-2024-0189, Direct Testimony of Lena Mantle, June 27, 2024, Exhibit LMM-D-2, pp. 10-11.
[12] Docket No. ER-2024-0189, Direct Testimony of Lena Mantle, June 27, 2024, p. 1.

FAC are volatile, unpredictable and largely beyond the utility's control. The sharing provision at least partially divorces rates from costs and can materially affect the utility's opportunity to earn a fair return on equity, and places undue and unneeded importance on the estimate of fuel and purchase power costs included in base rates. Ms. Mantle's proposal for EMW appears to be a reaction to what in her view is an overreliance on the market, rather than sound regulatory and ratemaking principles. Her recommendation has no applicability to Liberty's application, and if applied more generally, would represent a major departure from just and reasonable ratemaking.

Q. Is it common in other jurisdictions to not provide full cost recovery of fuel expenses?

A. No, this is quite uncommon. Nearly all traditionally regulated states in the United States have some form of energy cost recovery mechanism, and fuel and purchased power costs are traditionally considered "pass through" costs in utility ratemaking as these costs are large, volatile, and largely beyond the control of the utility. Specifically, the Company operates in three other retail jurisdictions and has a FERC approved Generation tariff, each of which provides full cost recovery of fuel expenses.

Q. Have other forms of sharing mechanisms been established by regulators?

A. Yes, although this is also quite uncommon. A small number of states do include some provision to share at least some categories of cost changes among customers and the utility. However, upon closer examination, it is clear that almost none have a mechanism like that which Liberty has currently in Missouri. Rather, the sharing is most commonly applied to profit margins *after* the utility is provided its full recovery of costs to serve customers.

I am aware of ten other regulatory jurisdictions (out of 52 in the U.S.) in which at least one utility has some form of sharing related to its FAC: Colorado, Hawaii, Idaho, Kentucky, Montana, Oregon, South Dakota, Washington, Wisconsin and Wyoming. However, as shown below there is only one other state that has a state-wide policy of sharing fuel costs for utilities in organized power markets, and that state, Wisconsin, has a much more constructive approach than is currently in use in Missouri.

In three of these states (Colorado, Kentucky, and South Dakota) sharing between the utility and customers is limited to the margins (i.e., profits) from off-system power or REC sales, which is a practice more applicable to states without a wholesale market. In those states, after providing full cost recovery, the utility is able to optimize and share in the profits derived from the portfolio of costs that the utility incurs to serve its customers. This is a far different model, which focuses on profit sharing, not placing full cost recovery at risk due to factors largely or entirely outside the utility's control. If there is no sharing of OSS or REC margins in an FAC, which is more common, the utility retains that benefit between rate cases. As discussed further below, there is virtually no traditional off-system sales activity that is applicable to Liberty because all of its energy clears through the SPP market and all of its generation is dispatched based on pool-wide load and resources.

Four states, Idaho, Oregon, Wyoming, and Washington, include sharing for variations between a benchmark and actual fuel and energy costs, but they differ importantly from Liberty in Missouri because they do not operate in organized wholesale markets. Hawaii also does not operate in an organized market, and its FAC sharing is limited to 2% of fossil fuel purchases. Sharing provisions for several of these states include earnings tests, tiered sharing, and deadbands.

The remaining two states, Montana and Wisconsin, operate in an organized wholesale electric market (as does Missouri) and have some form of sharing of costs in the FAC.[13] As later discussed, one state, Wisconsin, has adopted processes to help ensure that unforeseen cost differences tracked in the FAC do not create major earnings threats or opportunities for the regulated utilities. Provided below is a brief summary of each of Idaho, Hawaii, Montana, Oregon, Wyoming, Washington, and Wisconsin's FAC sharing provisions:

Idaho, Oregon, & Washington

Idaho Power's FAC mechanism includes a sharing provision under which annual rate adjustments reflect 95% of the difference between base rates and projected rates for certain costs. These costs are the sum of fuel expense and purchased power expense (excluding purchases from cogeneration and small power producers), less the sum of off-system surplus sales revenue and revenue from market-based special contract pricing.[14] An energy cost adjustment mechanism is in place for Avista that allows the company to defer 90% of the difference between actual net power costs and those included in rates.[15]

In Oregon, Portland General Electric has an Annual Power Cost Variance that includes 90% sharing outside of an asymmetrical deadband. No sharing occurs if actual costs between -$15M and +$30M compared to the forecast, and sharing is subject to a +/- 100 basis point earnings test.[16]

[13] Only a portion of Montana operates in wholesale electric market, representing approximately 10% of Montana's total load.
[14] Idaho Power Tariff, Schedule 55 Power Cost Adjustment.
[15] Avista Corporation, Form 10-K for the Fiscal Year ended December 31, 2023, p. 46.
[16] Portland General Electric, Annual Power Cost Variance Mechanism, Schedule 126.

In Washington, Avista Corp.'s energy recovery mechanism includes a graduated sharing of differences from a benchmark level. Avista's graduated scale includes a deadband of plus or minus $4M with no sharing, and tiered sharing thereafter. These sharing provisions are treated as deferrals rather than adjustments to the subsequent fuel period rate.[17] A similar power cost adjustment mechanism is in place for Puget Sound Energy ("PSE") that allows for variations in power costs between baseline power costs and actual power costs to be apportioned, on a graduated scale, between the company and customers. The power cost baseline levels are set, in part, based on normalized assumptions about weather (temperature, wind, and solar variables), hydroelectric, and power market conditions and forecasts. Excess power costs or savings are apportioned between PSE and its customers pursuant to the graduated scale and will trigger a surcharge or refund when the cumulative deferral trigger is reached. PSE's graduated scale includes a deadband of plus or minus $17M, with tiered sharing above and below that deadband.[18]

Montana & Wyoming

For Montana-Dakota Utilities ("MDU"), the difference between actual fuel and purchased power costs and those included in base rates are shared 90/10 between customers and shareholders through the fuel clause in Montana. There are no cost sharing provisions in the FACs for the other power companies in Montana, as far as I am aware. In Wyoming, fuel is shared 85/15 and purchased power is shared 95/5 for

[17] Avista Corporation, Form 10-K for the Fiscal Year ended December 31, 2023, pp. 45-46.
[18] Puget Sound Energy Inc. Form 10-K for the Fiscal Year ended December 31, 2023, pp. 9-10.

MDU.[19,20] Rocky Mountain Power's Energy Cost Adjustment includes 80/20 sharing.[21]

Hawaii

Hawaiian Electric Company's Energy Cost Recovery Clause (ECRC) includes a "Fossil Fuel Cost Risk Sharing Component" which shares 2% the difference between expected and actual *fossil fuel* costs, symmetrically. Sharing is capped annually, at +/- $2.5 million for Oahu, and lesser amounts for HECO's smaller island service territories.[22]

Wisconsin

Electric utilities in Wisconsin file an annual Fuel Cost Plan forecast and then track the actual fuel cost variance against that rate for deferral and future recovery or refund. There is a symmetrical 2% band of tolerance before deferral increases or decreases take effect. Under-collections that exceed the 2% annual tolerance band are recoverable unless utility earnings for that year exceed the authorized ROE. The cost recovery or refund on deferrals is addressed in the next FAC filing.[23] Importantly, the fuel factor is reset annually, whereas in Missouri it is reset only during base rate proceedings.

Q. You stated earlier that FAC sharing mechanisms in states that operate in non-organized markets do not provide a point of comparison for Missouri. Why is that?

A. Electric utilities operating in non-organized markets, which is how Liberty Missouri operated until the SPP market became fully functional in 2014, operate very differently,

[19] Montana-Dakota Utilities Co. Fuel and Purchases Power Cost Tracking Adjustment Rate 58 (Montana).
[20] Montana-Dakota Utilities Co. Power Supply Cost Adjustment Rate 50 (Wyoming).
[21] Rocky Mountain Power, Energy Cost Adjustment Mechanism, Schedule 95.
[22] Hawaiian Electric Company Energy Cost Recovery Clause, Revised Tariff Sheet No. 63, rates for Oahu.
[23] Wisconsin Administrative Code, Chapter PSC 116.03 Fuel Cost Plan.

and as such have many more opportunities to affect FAC costs through management actions, and can respond to incentives in ways that are no longer applicable to Liberty or other electric utilities in Missouri. Under the earlier non-organized operating model, utilities focused their dispatch and fuel procurement decisions on meeting their on-system requirements, and they engaged in wholesale market operations that allowed them to reduce costs through short-term and medium-term bilateral power sales and purchases which took advantage of heat-rate differentials, fuel cost differentials, load diversity, and transmission availability. All of those actions could be incentivized through the FAC sharing mechanism. Under the structure of the organized SPP market, those actions are collectively made by SPP for participating utilities such as Liberty, and transmission system planning and development occurs on a regional basis rather than for individual utilities. While there may still be limited opportunities for utilities to engage in bilateral transactions in SPP, those opportunities are more in the nature of resource planning and procurement than the extensive operational decisions that were made under the earlier market structure. Because today's market structure is so different, the effectiveness of and justification for FAC incentives should also be much different.

In a pre-organized market era there were power generation efficiencies to be found and thus it was reasonable to incentivize these activities via a sharing provision. However, in the organized market era with centralized dispatch, efficiencies are already implicit in the prevailing market price. In that way, the rationale for the inclusion of the sharing provision in earlier versions of Liberty's FAC is no longer applicable or appropriate.

IV. TRANSMISSION EXPENSE IN THE FAC

Q. Please describe your understanding of how transmission expenses are currently incurred by the Company.

A. Liberty is a *Network Integration Transmission Service* ("NITS") customer in the SPP market. As a NITS customer, Liberty optimizes its load-serving efficiency by utilizing a market geared toward maximizing economic commitment and dispatch efficiency. Liberty supports bulk electric transmission system investment through the "Schedule 11" charges. Schedule 11 charges primarily represent assets for which annual transmission revenue requirements are updated annually through formula rate mechanisms approved by FERC. Schedule 11 charges are either directly assigned, regionally allocated, or zonally allocated, to load. As a Load Serving Entity, Liberty pays those charges to SPP.

Q. Who has oversight of the transmission revenue requirement, and who has oversight of the development of new transmission projects?

A. FERC has to approve the transmission revenue requirement through a process that permits full involvement of regulators, customers, and other interested parties. Any costs, the prudence of the decisions underlying the costs, and whether the assets are used and useful can all be challenged at FERC. The development of additional transmission projects within SPP is governed by the SPP planning and interconnection processes and is administered through stakeholder engagement that includes regulators, generators, load serving entities, and others. In keeping with the energy transition, SPP and MISO are planning significant transmission buildouts to address current and future energy needs.

Q. Who has oversight of transmission cost allocation in SPP and therefore the costs that are charged through Schedule 11?

A. The Regional State Committee ("RSC") within SPP has the primary responsibility for determining Schedule 11 charges through cost allocation. The RSC is composed of one designated regulatory commissioner from each state within the SPP Region.

Q. Are these transmission costs within the control of the Company?

A. Largely no. While the Company is a participant in SPP's transmission planning process, it has only limited control over the projects being planned and no control over cost allocation. An electric utility's share of regional transmission expenses are not the type of costs to which any form of cost sharing should apply, especially since these costs will become an even larger expense as the energy transition continues. The expanded buildout will produce expenses that are likely to increase significantly, are certainly material, and are beyond the control of the company.

Q. Are all of Liberty's transmission expenses recovered through the FAC?

A. No. Transmission expenses are primarily recovered through base rates. As described in the testimony of Company Witness Aaron J. Doll, the Company incurs Schedule 1-A and Schedule 12 transmission expenses, which, as noted by Witness Doll, are largely not subject to FAC treatment. Liberty is recovering through its FAC less than 20% of eligible SPP transmission expense and approximately 50% of eligible MISO transmission expense. When transmission expenses increase in accordance with regional expansion plans and base rates are not updated, the Company will not be able to recover its share of those costs.

Q. Do you believe that transmission expenses should be recovered through the FAC?

A. Yes. There are two issues that I recommend that the Commission reconsider regarding transmission expenses. The first is the level of sharing, and as I discuss throughout this testimony, I believe that 100% of the costs that flow through the FAC should be recoverable. The benefits provided by a robust transmission system are clear, the rates are approved by FERC, and the Company has limited control over these costs. Whether actual costs are higher or lower than costs that were estimated in a base rate case has no bearing on whether the costs should be recoverable. Subjecting these costs to sharing, in which a meaningful level of costs may not be recoverable, is tantamount to disallowing a FERC approved rate for transmission service and as such should not be part of the FAC policy.

The second issue is which transmission expenses should be eligible for FAC treatment. As I discuss next, I recommend that as a matter of sound regulatory policy the Commission should allow all of Liberty's share of regional transmission expenses to be eligible for FAC treatment.

Q. You suggest that the Commission should "reconsider" FAC treatment of transmission expenses. Has the Commission previously opined on the issue of inclusion of transmission expenses in the FAC?

A. Yes. The Commission has previously stated that transmission costs associated with "prudently incurred fuel and purchased-power costs" should flow through the FAC, and has referenced the FAC statute in its decisions.[24] The FAC statute allows the Commission to "…approve rate schedules authorizing an interim energy charge, or periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its *prudently incurred fuel and purchased-power costs, including*

[24] See for example, Docket No. ER-2019-0374, Amended Report and Order, July 23, 2020.

transportation."[25] The Commission also explained in ER-2014-0351 that although SPP began operating an organized electricity integrated marketplace in 2014, effectively making all of Liberty's power production costs purchased power costs, that change in procedure had "not made Empire's fuel and purchased power costs more or less subject to Empire's control or predictable."[26] On that basis, the Commission has previously declined to provide FAC recovery for all of a utility's share of regional transmission expenses, but has relied on an examination of what portion of those transmission expenses relate to net purchased power intervals[27] and PPAs with parties other than the RTO. It is that conclusion that I believe the Commission should reconsider.

Q. Why is it time for the Commission to reconsider its prior ruling as to what the term "purchased power" costs should include and exclude for purposes of the FAC?

A. The Commission has concluded that "transportation" costs for purchased power are eligible for recovery, yet it has adopted a very narrow definition of what constitutes "purchased power." It is understandable that, at the time the FAC clauses were originally adopted, purchased power costs were expected to be a portion of a utility's resource portfolio, with the bulk of the resource portfolio being made up of power produced by the utility's own generation resources. As the markets and resource mix has evolved, the Company has become a full participant in an organized market. All of the power it produces is sold to that market, and all of the power it requires is purchased from that market. There is no difference in the transmission expense incurred to deliver

[25] Emphasis added.
[26] Docket No. ER-2014-0351, Report and Order, June 24, 2015, p. 24.
[27] This calculation considers net energy purchased during intervals (hours) when Empire is a net purchaser (i.e., purchases more energy than it sells).

power purchased under traditional PPAs and to deliver power purchased under RTO transactions.

Q. Do you believe that circumstances have changed since the Commission's past rulings?

A. Yes, I do, in two important ways. First, as part of the ongoing energy transition, there is much greater emphasis on connecting new generating resources and improving reliability, causing significant new transmission investment to be planned for the SPP region. At the same time, the share of SPP transmission expense recovered by the Company through the FAC has fallen from 34% to 19%, heightening the risk of the Company's ability to earn a fair and reasonable return. This is because the Company can incur higher transmission costs than it recovers through base rates. This creates significant issues of regulatory lag and recoverability of costs, which creates a less favorable climate for investment in Missouri's utilities. Currently the SPP transmission capital expenditures are planned to increase due to a record level of investment that is expected to produce a benefit-to-cost ratio above eight.[28] The importance of the buildout itself, as well as the importance of timely cost recovery, results in changed circumstances that warrant a reconsideration of this FAC policy as it applies to the utility's share of regional transmission expenses.

Q. Is timely cost recovery related to investor confidence?

A. Yes. Timely recovery for major investments is a critical element of how investors make decisions and a critical element of a supportive regulatory environment. Timely cost recovery bolsters investor confidence by ensuring that costs are recouped promptly,

[28] SPP 2024 Integrated Transmission Planning Assessment Report, October 7, 2024, p.1 https://spp.org/documents/72605/2024%20itp%20report%20draft%20v0.6.pdf.

thereby providing the utility with a reasonable opportunity to earn its allowed return. This supports further capital infusion into critical infrastructure projects, be they transmission, generation, or distribution. Bolstering investor confidence and protecting the Company's ability to earn a fair return ultimately provides customers with benefits in the form of reliability, resilience, environmental improvements and affordability. For these reasons, providing recovery for Liberty's share of regional transmission expenses through the FAC is sound regulatory policy.

V. CONCLUSION

Q. Please summarize your recommendations regarding the Company's FAC mechanism.

A. I recommend the Commission discontinue the sharing mechanism in the Company's FAC mechanism, and that 100% of the Company's Schedule 11, Schedule 12, and Schedule 1-A transmission expenses be eligible for inclusion in the FAC mechanism.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

VERIFICATION

I, John J. Reed, under penalty of perjury, on this 6th day of November, 2024 declare that the foregoing is true and correct to the best of my knowledge and belief.

/s/ John J. Reed