CONFIDENTIAL DESIGNATIONS

The Empire District Electric Company d/b/a Liberty

Case No. ER-2024-0261

RE: Surrebuttal Testimony of Aaron J. Doll - portions of pages 2-3, 6 and 17-18

The information is designated "Confidential" in accordance with Commission Rule 20 CSR 4240-2.135(2)(A)3, 4, and/or 7 due to the nature of the material regarding market-specific information relating to services offered in competition with others and goods or services purchased or acquired for use by a company in providing services to the customer. The confidentiality shall be maintained consistent with the referenced Rule and/or Section 386.480, RSMo., as the case may be.

Exhibit No.: _____
Issue(s): FAC, Price Sensitive Curtailments, Interruptible Credits, MPPM and AAO for Riverton Units 13 and 14
Witness: Aaron J. Doll
Type of Exhibit: Surrebuttal & True-Up Direct Testimony
Sponsoring Party: The Empire District Electric Company d/b/a Liberty
Case No.: ER-2024-0261
Date Testimony Prepared: September 2025

Before the Public Service Commission
of the State of Missouri

Surrebuttal and True-Up Direct Testimony

of

Aaron J. Doll

on behalf of

The Empire District Electric Company d/b/a Liberty

September 17, 2025

Liberty™

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20 CSR 4240-2.135(2)(A)3,4,7

PUBLIC VERSION

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THE EMPIRE DISTRICT ELECTRIC COMPANY D/B/A LIBERTY
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION
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SUBJECT **PAGE**

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Aaron J. Doll. My business address is 602 South Joplin Avenue, Joplin, Missouri.

Q. Are you the same Aaron J. Doll who provided direct and rebuttal testimony in this matter on behalf of The Empire District Electric Company d/b/a Liberty ("Liberty" or the "Company")?

A. Yes.

Q. What is the purpose of your surrebuttal & true-up direct testimony in this proceeding before the Missouri Public Service Commission ("Commission")?

A. The true-up portion of my testimony describes the extension for the Elk River Wind purchased power agreement ("PPA") that is incorporated into the FAC base factor update as described in Company witness Todd W. Tarter's true-up direct testimony. My surrebuttal responds to specific rebuttal issues raised by the Staff of the Commission ("Staff") and the Office of the Public Counsel ("OPC") and clarifies the Company's positions on those topics. In particular, I address:

- OPC Witness Mantle — the Company's Fuel Adjustment Clause ("FAC") base calculation;
- Staff Witness Mastrogiannis – Inclusion of Production Tax Credits ("PTC") within the FAC subaccounts and level of sharing for transmission revenues and expenses;

- OPC Witness Marke — price-sensitive curtailments (mechanics, customer protection, and system impacts);
- Staff Witness Jennings — the methodology and valuation of the interruptible credit;
- OPC Witnesses Payne and Mantle — application of the MPPM; and
- OPC Witness Robinett — the continued need for the AAO for Riverton Units 13 and 14.

As to these topics, I correct factual assumptions where necessary, provide additional context from the Company's planning and operations, and explain how the Company's proposals are designed to maintain reliability and minimize total customer cost.

II. TRUE-UP DIRECT

Q. Describe the extension to the Elk River Wind PPA.

A. **[redacted]

[redacted]

[redacted]**

[1] Current executed weighted average REC transactions: 2025-$2.47/REC, 2026-$3.88/REC, 2027-$4.49/REC, $2028-$4.70/REC.

III. FAC BASE CALCULATIONS

Q. OPC Witness Mantle claims the Company has intentionally "low balled" the FAC base to improve the optics of the general rate case. Do you agree?

A. No. This is not a new theme in Ms. Mantle's testimony. In Case No. ER-2019-0335[2], she advanced similar allegations of "gamesmanship" and "manipulation" of the FAC base. In this case, as in prior cases, the Company developed its FAC base using standard, transparent methods and provided workpapers identifying inputs that have been available to Staff and OPC.

Q. What recommendation did Ms. Mantle make in Case No. ER-2019-0335 based on her allegations?

A. She proposed reducing the utility's FAC sharing mechanism from 95%/5% to 85%/15%.

Q. What does Ms. Mantle recommend here?

A. She recommends a 50%/50% sharing mechanism for Liberty.

Q. Does Ms. Mantle describe exactly how she believes the Company manipulated the FAC base?

A. No. Ms. Mantle raises broad concerns about the provenance of the data used in the Company's fuel modeling, but she does not identify any specific mechanism by which the FAC base was allegedly altered – either within the model itself or during post-processing. Her rebuttal testimony critiques the Company's direct testimony for not detailing how inputs were annualized or normalized, for not further substantiating the reasonableness of hourly market prices beyond their correlation to gas prices, and for

[2] In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Decrease Its Revenues for Electric Service.

not elaborating on the continued exclusion of natural gas hedging in this case. While the Company intends to address her concerns regarding perceived disclosure gaps, it is important to clarify that these issues are entirely unrelated to any form of manipulation. Rather, several of Ms. Mantle's statements reflect a misunderstanding of key market fundamentals. Her testimony selectively emphasizes procedural elements that are immaterial to the outcome, while downplaying or overlooking material market dynamics, many of which are outside the Company's control.

Q. What statements reflect misunderstanding of market fundamentals?

A. The following are two examples:

1) **Bidding discretion**: Ms. Mantle states, "Liberty chooses when and at what price it bids its generating units into the energy markets." In SPP, unit offers are constrained by cost-based reference levels and market-power mitigation; operational constraints (minimum run times, start costs, ramp rates, fuel transport, emissions) bind decision-making; and available capacity must be offered into the real-time balancing market. Utilities do not have unfettered discretion to "choose when and at what price it bids."

2) **Congestion-hedging process (ARR/TCR)**: Ms. Mantle claims the Company exerts "substantial control" over fuel and purchased-power costs because it "chooses how much of its Auction Revenue Rights to convert to Transmission Congestion Rights." This framing is misleading because it spotlights a less material step, Transmission Congestion Rights ("TCR") conversion, while omitting the material step that precedes it: obtaining the Auction Revenue Rights ("ARR") in the first place.

- ARR nomination and allocation are governed by SPP's rules, feasible-flow tests, system topology, and historical patterns. Utilities have limited control over what ARR entitlements are actually awarded; we cannot "choose" to receive ARRs at will.

- TCR conversion, the step Ms. Mantle highlights, is a secondary hedge decision made *after* ARRs have been allocated. Its effect is incremental relative to whether ARRs were awarded at all. By focusing on conversion, and skipping over entitlement, Ms. Mantle creates the impression that the Company has broad discretion over congestion outcomes. That is incorrect and does not accurately portray how congestion risk is actually managed.

Q. Do other OPC witnesses support the claim that the Company artificially lowered the base?

A. No. OPC witness Schaben contends in her direct testimony that the TCR revenue embedded in the Company's direct case (**[redacted]**) is too low and should be increased to [redacted]**. All else being equal, increasing expected TCR revenues would reduce the FAC base (by approximately **[redacted]**) and lower the overall revenue requirement (by **[redacted]**). If OPC believed the Company was manipulating the base downward, it is difficult to reconcile that theory with their simultaneous claim that TCR revenues were understated, a change that would further lower the base. The positions are inconsistent.

Q. Does OPC show that Liberty "manipulated" the FAC base?

A. No. OPC's testimony repeats a pattern it has advanced against other Missouri investor-owned utilities in prior cases, alleging "low-balling" of the base to justify tightening the sharing mechanism. However, it identifies no concrete step where Liberty altered inputs, modeling, or post-processing to bias the result. It elevates a less-material aspect of congestion hedging, TCR conversion, to imply broad Company control, while downplaying the materially determinative step of ARR nomination/allocation, which is governed by SPP rules and largely outside the Company's control. OPC also presents no competing production-cost run or quantified alternative base, and its own witness's proposal to **increase** expected TCR revenues would, if anything, lower the base, undercutting the "low-ball" narrative.

Q. Where should the Commission look for modeling specifics and figures?

A. The modeling framework, updated assumptions, and the revised base factor and offsets, may be found in Liberty witness Todd W. Tarter's true-up direct and accompanying schedules (TWT-1/-2), which describe the Encompass methodology, updated gas assumptions, and ARR/TCR/REC treatments.

IV. STAFF RECOMMENDATIONS RELATED TO PTC AND TRANSMISSION REVENUES AND EXPENSES

Q. What does Staff witness Mastrogiannis state regarding the PTC account being included in the FAC subaccounts?

A. Ms. Mastrogiannis states that the update to account 456230 for PTC revenue wind, being updated to account 409115 Provision Federal Income Tax – Production Tax Credits, should not be included as an FAC subaccount due to it not being related to fuel and purchased power.

Q. Do you agree with Staff's approach?

A. No. This account is to reflect the Company's share of the production tax credits related to the generation at the wind farms. Customers should receive the benefit of PTCs through the FAC because it ensures that the financial advantages of renewable energy generation are passed directly to customers faster than if they were included in the base rates. Additionally, in Case No. ER-2021-0312, Ms. Mastrogiannis states "Staff included subaccounts for Paygo, tax equity distributions, PTCs, and RECs in the FAC. Staff determined that it is appropriate to include these since all of these components are tied to Empire's new wind generation."[3]

Q. Staff witness Mastrogiannis indicates in rebuttal she opposes the inclusion of 100% transmission costs and revenues within the FAC. Has your position changed regarding this topic?

A. No. The Company continues to support that transmission expenses and revenues should be eligible for inclusion within the FAC at 100%. For further details refer to my rebuttal testimony and John Reed's surrebuttal testimony.

V. <u>INVOLUNTARY INTERRUPTIONS BASED ON VOLL STUDY RESULTS</u>

Q. OPC witness Dr. Marke raises the concept of involuntary interruptions. What is the Company's position on using "high-price" triggers to interrupt retail load?

A. We have strong concerns with price-triggered retail curtailment. The approach presents concerning safety risks, does not align with the timing of gas and power price formation, and can degrade system reliability by reducing available generation at critical hours.

Q. What are the primary safety risks?

A. A price-based trigger cannot reliably identify and protect vulnerable customers in real time. Without a verified medical-baseline/critical-care registry with automatic exemptions and positive notification/confirmation prior to de-energizing, there is a material risk of interrupting customers who depend on electricity for life-sustaining equipment. Those risks outweigh any prospective commodity savings.

[3] Case No. ER-2021-0312, Mastrogiannis rebuttal testimony p. 8.

Q. Do you have concerns with market mechanics to implement price-triggered curtailment?

A. Yes. Although price-triggered demand response programs are a good fit for this thesis, deploying them broadly against a large customer base rather than individually based on customer selection makes this challenging. The decisive prices arrive too late or are too uncertain to drive safe retail actions. Physical spot gas is procured ahead of flow while daily index prices are published afterward; day-ahead Locational Marginal Prices ("LMPs") can diverge materially from real-time, and real-time LMPs are only known just before the 5-minute interval and any impact would be dependent on your Day-Ahead ("DA")/Real-Time ("RT") DA/RT position exposure. A tariff keyed to "high prices" would either trigger after consumption or rely on volatile forecasts, neither is an appropriate basis for retail shutoffs.

Q. What are the system-level consequences in regard to "not buying gas" or curtailing to avoid price spikes?

A. If gas is not secured, gas-fired units cannot be committed and offered when the system is in need of supply. That reduces available supply, can worsen scarcity pricing, and degrades measured performance. Repeated unavailability/under-performance can reduce accredited capacity within performance-based accreditation frameworks, weakening resource-adequacy positions and ultimately increasing costs through replacement capacity or penalties not to mention jeopardize reliability.

Q. Can the Company do something with high-price signals to provide value to customers?

A. Possibly. High-price signals could be used as a planning and operational metric for distribution-side storage, rather than for retail shutoffs. High-price/constraint hours can guide siting and dispatch of feeder-level or community batteries (and other non-wires solutions) that charge off-peak and discharge during stressed hours. This approach mitigates peaks and congestion without exposing medically vulnerable customers, and it supports reliability and accreditation outcomes.

Q. Will the Company engage with OPC in the future on this topic?

A. Absolutely. The Company is always interested in exploring opportunities to increase value for customers, so long as it is done safely, reliably, and with an eye toward avoiding unintended consequences.

VI. INTERRUPTIBLE CREDIT VALUATION

Q. Please summarize the purpose of your testimony in this section.

A. I evaluate the basis for the interruptible (demand response) credit and the comparison presented by Staff witness Jennings, who used operating-cost figures for a combined-cycle gas turbine ("CCGT") from the Company's Integrated Resource Plan ("IRP"). I explain why that comparison materially understates the value of interruptible capacity, and I recommend a more appropriate benchmark tied to the Cost of New Entry (CONE) on an accredited capacity basis. Below is some helpful background for this section:

- In the Southwest Power Pool ("SPP"), there is no centralized capacity market; Load Responsible Entities ("LRE") satisfy Resource Adequacy ("RA") requirements using accredited resources and must meet seasonal Planning Reserve Margins ("PRM").
- CONE is the annualized cost of capacity of a reference unit (capital carrying charges plus fixed O&M). RTOs use CONE as the benchmark for the valuation of capacity.

- Accredited Capacity is the capacity that is counted for purposes of complying with RA requirements after adjusting for performance/availability.

Q. Did you review Staff witness Jennings' calculation for the costs of operating a Combined Cycle Gas Generator ("CCGG") utilizing data from the Company's latest Integrated Resource Plan ("IRP")?

A. Yes.

Q. What concerns do you have with his calculations?

A. I have three primary areas of concern:

1. <u>Category Mismatch (Operating Cost vs Capacity Valuation)</u>. Mr. Jennings built a benchmark from operating-cost line items, specifically:
    a. fixed O&M,
    b. ongoing Capex, and
    c. firm natural gas delivery.

    That construct omits the capital carrying charges of a new plant, which are a dominant component of capacity value. Using only operating costs to value an RA product will dramatically understate the appropriate comparison.
2. <u>Firm fuel delivery treatment</u>. For capacity accreditation purposes, it may not be appropriate in all cases to include firm fuel transport as a fixed cost. Because SPP's CONE is anchored to a simple-cycle combustion turbine (SCCT), units with on-site backup fuel may reasonably meet reliability requirements without year-round firm gas service. Consistent with that construct, firm fuel delivery is not presently treated as a fixed component in SPP's CONE. If that element is excluded from the IRP-based proxy created by Witness Jennings, the remaining

fixed line items equate to approximately $1.81/kW-month, which appears materially below a reasonable proxy for accredited capacity value.

3. <u>Installed Capacity vs Accredited Capacity</u>. The operating-cost approach does not address capacity accreditation ("UCAP"). RA compliance and pricing are based on accredited capacity, not installed capacity ("ICAP")

Q. What is a fair benchmark for an interruptible credit in SPP?

A. In a footprint without a capacity market, the reasonable proxy is CONE on an accredited basis.

Q. What is SPP's current CONE rate and how was it constructed?

A. The current value is $85.61/kW-year, or $7.13/kW-month. By construction, CONE is the sum of Capital Recovery Costs (annualized carrying charges on overnight capital) plus Fixed O&M, expressed on a $/kW-year basis.

Q. Is the Capital Recovery Costs the same thing as the *Ongoing Capex* that Mr. Jennings used in his calculation?

A. No. Ongoing Capex is a modest allowance for periodic sustaining capital to keep an existing unit in service. Capital Recovery Costs represent the annualized cost of the initial investment (return on and of capital, taxes, depreciation, i.e.,). They are not interchangeable.

Q. What is SPP's Capital Recovery Cost rate and Fixed O&M in its current $85.61/KW-Month CONE rate?

A. As reflected in materials from the former Capacity Margin Task Force (CMTF) and referenced by SPP witness Nickell[4], the Capital Recovery Costs are $78.32/kW-year, and Total Fixed O&M is $7.29/kW-year, summing to $85.61/kW-year (=$7.13/kW-

[4] FERC Case No. ER18-1268.

month). The below Table AJD-1 (from DR 497) compiles the inputs Staff used from the Company's 2025 IRP; Table AJD-2 reproduces the CMTF roll-up used in SPP's filing[5].

Table AJD-1

2024 Fixed O&M ($/kW-year)	$ 17.80
Firm Gas Delivery ($/kW-year)	$ 27.05
Ongoing Capex ($/kW-year)	$ 3.86
Total	**$ 48.71**

Table AJD-2

Capital Recovery Costs	$ 78.32
Fixed O&M	$ 7.29
Total Fixed Costs	**$ 85.61**

Q. Is it reasonable to value interruptible capacity using only fixed annual operating costs from an IRP table?

A. No. Limiting the analysis to fixed operating items (with or without firm gas delivery) devalues interruptible capacity and is inconsistent with how capacity is procured and priced for RA. A more appropriate comparison is CONE (accredited), not a partial operating-cost subtotal.

Q. Staff witness Jennings asserts that increasing the interruptible credit "benefits the one at the cost of the many." Do you agree?

A. No. Properly set, the interruptible credit reflects avoided capacity costs for the entire customer base. In practice:

- The Company has maintained RA compliance and made off-system capacity sales that reduced revenue requirements for all customers, enabled in part by capacity length supported by interruptible load.

5 https://www.spp.org/Documents/28746/CMTF%20Agenda%20&%20Background%20Materials%2020150513.zip

- The Company has operated near SPP's RA margin in recent years. Falling below the LRE requirement would trigger deficiency charges (subject to prudence review) that ultimately costs customers.
- Importantly, a load-modifying resource is not merely one-for-one with generation. Reducing 1 MW of peak load lowers the obligation to serve that MW and the obligation to carry reserves on that same MW. With the Summer PRM ~16% (rising to 17% in 2029) and Winter PRM ~36% (rising to 38% in 2029), the capacity value of 1 MW of DR exceeds 1 MW of nameplate generation on a responsibility basis.

Q. On behalf of the Midwest Energy Consumers Group, Kavita Maini proposed a credit level in her rebuttal testimony. Is the credit level reasonable?

A. The credit rate is reasonable and in line with other proxies for the value of capacity. It is below CONE and, because it is paid in exchange for an accredited, testable capacity product that reduces both load and required reserves, it represents a fair, system-beneficial proxy for avoided capacity in a tight SPP RA environment.

VII. MPPM

Q. OPC witnesses Payne and Mantle allege that the Company is calculating the MPPM incorrectly. Do you agree?

A. No. The Company calculates the MPPM exactly as the Commission approved in Case No. EA-2019-0010, and as later clarified in the Fourth Partial Stipulation and Agreement in Case No. ER-2021-0312.

By contrast, OPC's approach would alter the bargain post hoc. Ms. Mantle introduces elements that were never part of the adopted methodology (for example, crediting Ozark Beach Dam or counting rooftop-solar amounts above the 2% Missouri

RES solar carve-out) and, at other times, seeks to strip out core pieces of the construct altogether. A clear example of a similar effort is her proposal in Case No. ER-2021-0312[6] to eliminate the PPA Replacement component—offered without analysis or evidentiary rationale. That kind of proposal is not a “clarification”; it is an attempt to renegotiate a settled methodology because she does not prefer the construct.

This pattern of adding new terms that were never agreed to and discarding agreed terms without reason raises threshold concerns about revisiting a Commission-approved deal. As we show later in this testimony, the Company did not support those additions, and the disputed provisions were removed in the final compromises. In short, the Company is applying the MPPM as approved; OPC is attempting to change the deal.

Q. Where in the original MPPM construct are credits for Ozark Beach Dam that reduced the PPA replacement?

A. Nowhere. I am not aware of any discussion, example, or provision in Case No. EA-2019-0010 or in the Fourth Partial Stipulation and Agreement (Case No. ER-2021-0312) that includes Ozark Beach credits in the MPPM calculation. Ozark Beach has operated since 1913; if such credits were intended, they would appear in the Non-Unanimous Stipulation and Agreement (Case No. EA-2019-0010) or the Fourth Partial Stipulation and Agreement (Case No. ER-2021-0312). They do not.

Q. Was the 1.25% credit addressed in Case No. EA-2019-0010 or Case No. ER-2021-0312?

A. It was not part of the original MPPM construct in Case No. EA-2019-0010. In Case No. ER-2021-0312, the 1.25% credit for Missouri wind projects was proposed by OPC

[6] Case No. ER-2021-0312, Mantle surrebuttal, p. 26.

as part of the Fourth Partial Settlement and Agreement, but the Company rejected its inclusion, and it was not included in the final settlement document.

Q. Was rooftop solar addressed in Case No. EA-2019-0010 or Case No. ER-2021-0312?

A. It was not part of the original MPPM construct in Case No. EA-2019-0010. In Case No. ER-2021-0312, rooftop solar was mentioned only at settlement as a Company concession to recognize the 2% Missouri RES solar carve-out—nothing beyond that.

Q. Did the Company also concede to adding Ozark Beach credits, a 1.25% multiplier on Missouri wind or rooftop solar credits beyond the 2% carve-out?

A. No. Ms. Mantle's Rebuttal Schedule LMM-R-3 reflects proposed changes to core MPPM terms. The Company was willing to acknowledge the 2% solar carve-out, but it did not accept additional language expanding credits. We stated we could not agree to those added terms; OPC removed them; and the executed settlement does not include the deleted language. A term proposed, rejected, and removed before execution is not part of the bargain.

Q. The Elk River Wind power purchase agreement (PPA) has been extended (as described earlier in my testimony). Should that affect the PPA-replacement treatment under the MPPM?

A. No. When the MPPM agreement was executed and later clarified, the Elk River Wind PPA was scheduled to expire in December 2025. That timing aligned with the Company's IRP and our then-current capacity and energy needs. Since that time, however, SPP's resource adequacy (RA) framework has changed materially: the Winter Planning Reserve Margin moved from no enforceable penalty for not meeting

15%, to 36% within only a few years, with filings[7] stating it will rise to 38% in 2029/2030. In that evolving environment, the Company had to preserve RA compliance in a way that remained least-cost for customers. We evaluated several interim options to bridge to new capacity and, on balance, an extension of the Elk River Wind PPA was the most practical "bridge" resource, one that also lowers fuel costs for the next 3.5 years.

Q. **[redacted]

A. [redacted]**

In light of those facts, it would be reasonable to recognize that the Company acted prudently to sustain reliability and reduce costs under rapidly changing RA requirements. The Company respectfully submits that it should not be penalized for

[7] FERC Filing No. ER25-89.

executing an agreement that provides clear, quantifiable value to customers while responsibly bridging to new capacity.

Q. Please summarize your position relating to the MPPM?

A. The Company applies the MPPM exactly as the Commission approved in Case No. EA-2019-0010, as later clarified in the Fourth Partial Stipulation and Agreement in Case No. ER-2021-0312. Proposals that were raised but not adopted, such as Ozark Beach credits, the 1.25% Missouri wind multiplier, or incremental rooftop-solar credits beyond the 2% RES carve-out were removed from the negotiated text and are not part of the approved methodology. Settlement agreements reflect negotiation and compromise; terms that were proposed, rejected, and deleted cannot be imported now. If parties wish to change parameters, the proper course is a prospective proposal, not a retroactive reinterpretation of a finalized agreement.

At the same time, the resource-adequacy landscape in SPP has shifted materially since the MPPM was crafted, particularly with respect to rising Planning Reserve Margins. **[redacted]**

Considering the above, Liberty's position is straightforward: the Company continues to apply the MPPM as approved, and the ERW extension is a prudent, customer-focused bridge executed within a rapidly changing RA environment. I respectfully submit that the record shows the ERW extension delivers clear, quantifiable value and was undertaken to protect customers and reliability, not to game the MPPM. Accordingly, the Company should not be penalized for taking a prudent step that benefits customers while maintaining compliance with the approved methodology. If stakeholders desire different treatment going forward, that discussion should occur through a prospective adjustment to the MPPM, not through retroactive re-interpretation.

VIII. RIVERTON NATURAL GAS AAO REQUEST

Q. OPC Witness Robinett states that the Company no longer needs the Accounting Authority Order ("AAO") related to Riverton Unit 13 and Unit 14 due to the recent implementation of Senate Bill 4. Is the Company in agreement?

A. Yes. Now that new natural gas facilities qualify for Plant In Service Accounting ("PISA") treatment, the Company, consistent with its direct testimony, is no longer requesting an AAO to track costs associated with the construction of Riverton Unit 13 and Unit 14.

IX. CONCLUSION

Q. Does this conclude your surrebuttal & true-up direct testimony at this time?

A. Yes.

VERIFICATION

I, Aaron J. Doll, under penalty of perjury, on this 17th day of September, 2025, declare that the foregoing is true and correct to the best of my knowledge and belief.

/s/ Aaron J. Doll