COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS	)	**CASE NO. 2025-00113**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS	)	**CASE NO. 2025-00114**

REBUTTAL TESTIMONY OF
ELIZABETH J. "BETH" MCFARLAND
VICE PRESIDENT, TRANSMISSION
ON BEHALF OF
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: September 30, 2025

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INTRODUCTION

Q. Please state your name, position, and business address.

A. My name is Elizabeth J. ("Beth") McFarland. I am Vice President of Transmission for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 820 West Broadway, Louisville, Kentucky 40202.

Q. What is the purpose of your rebuttal testimony?

A. I rebut certain positions advanced by Randy Futral, who testified on behalf of the Attorney General ("AG") and Kentucky Industrial Utility Customers, Inc. ("KIUC"), concerning miscellaneous transmission expenses in the test year for account 566. I also rebut the criticisms of Jason W. Hoyle, a witness for Kentucky Solar Energy Industries Association ("KY SEIA"), and James Fine, a witness for Joint Intervenors Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association ("Joint Intervenors"), regarding the Companies' study and conclusions pertaining to zero avoided transmission capacity costs attributable to Rider NMS-2 customers.

MISCELLANEOUS TRANSMISSION EXPENSES

Q. What is Mr. Futral's criticism of the Companies' miscellaneous transmission expenses in account 566 for the test year?

A. The miscellaneous expenses in the forecast test year are increased from previous years for both KU and LG&E. Mr. Futral claims the increases are not supported and should be disallowed unless adequate evidence supporting the increase is introduced.

Q. How do miscellaneous transmission expenses in the test year compare to the base year?

A. For KU, base year miscellaneous transmission expenses in account 566 are $32.5 million, and test year expenses are $36.2 million, an approximate increase of 11.2 percent. For LG&E, base year miscellaneous transmission expenses in account 566 are $13.1 million, and test year expenses are $14.3 million an approximate increase of 9.6 percent.

Q. Did the Companies explain the increases in response to data requests?

A. Yes. As Mr. Futral acknowledges in his testimony, in response to AG-KIUC 2-14 the Companies provided the following explanation for the increases in miscellaneous transmission expense in the test year, broken down by category:

Kentucky Utilities:

The 11.2% ($3.627 million) projected increase in FERC 566 in the test year is due primarily to the following:

- $2.693 million higher depancaking expense in the test year due to the projected increase in the Midwest Independent System Operator (MISO) rate.
- $0.310 million higher Reliability Coordinator and Independent Transmission Operator contractual cost increases in the test year.
- $0.325 million higher substation administrative contract labor and material expenses in the test year.
- $0.109 million higher NERC fees
- $0.070 million periodic ARC Flash expense occurring every 5 years, including the forward test year.

- $0.049 million higher FAC-008 BES Walkdown expense in the test year.[1]

Louisville Gas & Electric Company:

The 9.6% ($1.257 million) projected increase in FERC 566 in the test year is due primarily to the following:

- $1.016 million depancaking expense is higher in the test year due to the projected increase in the Midwest Independent System Operator (MISO) rate.
- $0.197 million higher Reliability Coordinator and Independent Transmission Operator contractual cost increases in the test year.[2]

Q. Can you provide the raw data support for each of these increases for both Companies as Mr. Futral requests?

A. Certainly. It is attached as Rebuttal Exhibit HDM-4 Misc Transmission Expense to Heather D. Metts' rebuttal testimony.

Q. Why are depancaking expenses projected to increase in the forecasted test year?

A. As the Companies explained in response to the data requests reproduced above, depancaking expense is driven by publicly-available MISO rates broken down by different rate schedules paid by the Companies. For business planning purposes, the Companies project future adjustments in depancaking expense using a 5-year historical average of those rates. Over the five-year period from June 2019 through June 2024, the most recent data available when the Companies created their business plan, the average increase in the largest MISO rate components, which are rate schedules 7 and

[1] The Companies filed a supplemental response to AG-KIUC 2-14(d) (KU) and AG-KIUC 2-14(c) (LG&E) on September 30, 2025. These figures reflect the updated depancaking variance provided in the supplemental response. KU Response to AG-KIUC 2-14(d); Futral Testimony, Exhibit RAF-8.

[2] LG&E Response to AG-KIUC 2-14(c); Futral Testimony, Exhibit RAF-8.

8, was 8.06 percent. The projected increases in depancaking expense roughly approximate that average increase in applicable MISO rates as further detailed in Rebuttal Exhibit HDM-4 Misc Transmission Expense.

Q. Mr. Futral acknowledges that the Companies seek deferral accounting treatment for depancaking expenses but asserts that does not justify setting expense levels in base rates unreasonably high. How do you respond?

A. I agree. But the depancaking expenses in the forecast test year are not unreasonably high. They are based on reasonably anticipated increases in MISO rates according to five-year historical averages. The projection is significantly lower, for example, than the increase in MISO rates paid by the Companies from June 2023 to June 2024, which was greater than 17 percent. Nevertheless, under the current accounting treatment for depancaking expenses, any overestimation of depancaking expense in the forecast test year would be recorded as a regulatory liability and credited back to customers in a future rate case.

Q. Please expand on the support already provided for the other increases to miscellaneous transmission expense in the forecast test year.

A. Nearly all contributors to the increase in miscellaneous transmission expense in the test year are non-discretionary. The Companies are facing contract increases for mandatory contract services from base year to test year including services provided by their Reliability Coordinator (17% increase) and Independent Transmission Operator (2% increase). Increases in NERC fees (13% increase) in the test year are based on publicly-available budget estimates from NERC.[3] Amounts allocated for an ARC flash study ($42k for LG&E and $70k for KU) in the test year are incremental to the base year because the study is scheduled to be completed in the test year. Substation administrative expenses are increased from the base year to the test year just over $300k for KU but are lower in the test year for LG&E. The increases in substation administrative expense for KU include approximately $190k in incremental costs for relocating a substation office/warehouse in Lexington, $100k associated with backfilling 3 existing positions for safety and related new employee training, commercial driver's licenses (CDL), and expenses for new employee equipment (tools, communications and uniforms), $70k for enhanced employee substation training starting in 2026, and $40k for the rollout of incremental and enhanced safety programs.

AVOIDED TRANSMISSION CAPACITY COSTS FOR RIDER NMS-2

Q. Are there currently any avoided transmission capacity costs created by net exports from Rider NMS-2 customers?

A. No. As my direct testimony and Exhibit BJM-3 to my testimony demonstrate, the Companies performed a study to determine whether there are any potential cost savings on the transmission system through avoided transmission infrastructure upgrades due to net metering customers. The Companies created two sets of models, one including net metered generation and one that did not and thus had higher summer peak load levels. Standard simulation and analyses were applied to both models to identify any overloads or voltage violations. Two of the simulations showed no MVA flow or

[3] *See* 2024 NERC Business Plan and Budget Overview, available at: https://www.nerc.com/gov/bot/FINANCE/BusinessPlanandBudget/NERC%20Final%202024%20Business%20Plan%20and%20Budget%20Overview.pdf, at p.16.

voltage violations without NMS-2 distributed generation. The third (P3) simulation, which modeled a loss of a single generator unit, followed by system adjustments and additional P1 contingency simulations, showed a potential for MVA flow and voltage violation in one extreme scenario without net-metered distributed generation, but the impacts on both MVA flow and voltage were very small and considered insignificant per LG&E/KU Transmission Study Criteria, meaning there is not enough impact to effect any change on transmission system upgrades.[4]

Q. Please summarize the criticisms of the intervenor witnesses on the Companies' analysis and conclusions regarding avoided transmission costs due to NMS-2 customers.

A. Kentucky SEIA's witness, Mr. Hoyle, opines that: (1) the Companies failed to consider the impact of solar generation in winter peak models because it was assumed to be zero; (2) the avoided cost study did identify *some* risk reduction in one modeled scenario due to net-metered distributed generation and that risk reduction should be compensated; (3) the Companies' modeling fails to consider the impact of net-metered resources in combination with other efficiency programs; and (4) the model does not consider the opportunity cost of transmission capacity. Mr. Fine, a witness on behalf of the Joint Intervenors, asserts that the Companies failed to follow the Commission's direction on calculating avoided transmission costs and failed to consider certain opportunities for avoided costs in high DER scenarios.

Q. Do you agree with any of these intervenor criticisms?

[4] McFarland Direct Testimony, Exhibit BJM-3.

A. No. And it is noteworthy that no intervenor has offered a realistic alternative analysis of avoided transmission capacity costs attributable to the Companies' NMS-2 customers. Instead, the intervenors have simply offered critiques of the Companies' analysis without proposing their own viable framework. I will address each of those criticisms in turn.

Q. Was it appropriate for the Companies to exclude winter peak models from the avoided transmission cost analysis?

A. Yes, winter peaks across the system have historically occurred in the early morning before sunrise or evening after sunset when these resources are not producing energy and thus not contributing to offset peak demand.[5] Mr. Hoyle suggests that battery storage co-located with solar generation could shift DER exports to meet periods of higher demand. But as Mr. Hornung describes in his rebuttal testimony, battery storage does not qualify as an eligible electric generating facility under Kentucky's net metering statutes and Rider NMS-2 makes no provision for addressing or compensating energy storage. Finally, while distributed wind-generation could theoretically contribute to meet winter peak demand, the fact is there are no such resources currently on Rider NMS-2.

Q. What is the value of the reduced risk of MVA flow violation and voltage violation found in the Summer 90/10 model attributable to net-metered DERs?

A. The value is zero. The study resulted in a minor change to two constraints, however, the impact to these violations attributed to DER installations is so minimal that they do

[5] KU Response to KY SEIA's Requests for Information, No. 3(a) (Jul. 16, 2025).

not meet the Companies criteria for significant impact as outlined in the LG&E/KU TSR Study Criteria document.

Q. How do you respond to Mr. Hoyle's criticism that the Companies' avoided transmission cost analysis does not consider the impact of DERs in combination with efficiency or demand response programs?

A. The purpose of the Companies' impact study filed with my testimony was to isolate the effects of DERs operated by net-metering customers on potential transmission infrastructure upgrades. That effect was determined to be zero. Whether there would be a theoretical impact from DERs in combination with myriad other factors that affect capacity on the transmission system, including efficiency upgrades or demand programs, does not directly bear on the question of whether there is avoided cost due to the presence of DERs or the value of exports from DERs. And as a practical matter, it would be extremely difficult if not impossible to isolate the impact of DERs, by themselves, in such a scenario, except to model that impact in isolation, which is what the Companies have done in this case.

Q. Is it appropriate to consider the opportunity cost of transmission capacity in assessing the avoided cost due to net-metered DERs?

A. No. DERs have the potential to increase overall transmission capacity by reducing flows on the transmission system, freeing up additional capacity that could be marketed. However, any potential additional capacity would have to be marketed as non-firm capacity due to the non-firm nature of distributed generation resources – which the companies do not plan for and is marketed on an as-available basis. Intermittency, seasonality, and the inability to dispatch these resources would put the overall reliability of the transmission system at risk if we considered these resources for the purposes of providing incremental firm transmission capacity in the long-term planning and operation of the grid.

Q. Does Mr. Hoyle offer a competing calculation for avoided transmission capacity cost?

A. No, Mr. Hoyle does not have a different proposal.

Q. Please respond to Mr. Fine's suggestion that the Companies failed to follow the Commission's guidance for calculating avoided transmission capacity costs in the 2020 rate cases.

A. In the 2020 rate cases, the Commission performed its own avoided transmission capacity cost calculation using a modified version of the Minnesota VOS approach that the Companies cannot replicate.[6] While the Commission ordered certain NMS-2 export rates based on avoided transmission capacity costs which it found to be prudent and reasonable, it did not prospectively require the Companies to use a particular methodology for calculating avoided transmission capacity costs due to NMS-2 customers in the future, nor did it establish a "benchmark" for avoided transmission capacity as Mr. Fine suggests in his testimony. In fact, the Companies have been unable to replicate the Commission's modeling of avoided transmission capacity costs because the underlying data, workpapers and formulas for the calculation were not provided.[7]

Q. Mr. Fine suggests that the Companies have failed to assess the possibility of avoiding transmission expansion projects for their own new generation resources in high DER scenarios. Have they?

[6] 9/24/21 Final Order, Case Nos. 2020-00349, 2020-00350, at 52-54.
[7] *See* KU Response to Commission's Fourth Requests for Information, No. 13(c) (Sept. 23, 2025).

A. No. The primary objective of transmission planning is to provide firm transmission service from designated network resources (DNRs) to load in a least cost manner while complying with all rules and regulations every hour of the year. NERC Reliability Standard TPL-001 and the LGE/KU Open Access Transmission Tariff sets the standards at which the Companies plan and operate their transmission system. NMS resources are not considered firm generation for the reasons of their intermittency and inability to be dispatched as needed. Additionally, Mr. Fine generally mischaracterizes the need for transmission investment proposed by the Companies as being related to generation expansion.[8] As outlined in the Transmission System Hardening and Resiliency Program (TSHARP) document and my direct testimony, the majority of the proposed investment being sought for transmission is aimed at improving the resiliency of the transmission system through replacement of aged assets.

Q. How do you respond to Mr. Fine's suggestion that "dumb and disconnected" DERs can add burdens to the grid but "connected" DERs can be optimized?

A. Generally this aligns with Mr. Waldrab's direct testimony concerning the conditions necessary to optimize DERs and realize avoided capacity savings. But as Mr. Conroy notes in his rebuttal testimony, Rider NMS-2 does not contain a mechanism for the Companies to exert control over the dispatchability of distributed generation resources that would be necessary to create the potential for avoided costs.

Q. Is Mr. Fine's proposed avoided transmission capacity cost calculation reasonable?

A. Unlike Mr. Hoyle, Mr. Fine offers an alternative proposal for calculating avoided transmission capacity costs due to net-metered DERs. But it is not accurate or

[8] Fine Testimony at 27.

reasonable. Specifically, Mr. Fine proposes a value for avoided transmission capacity costs of $0.0191/kWh for both utilities that is determined using past transmission rates. These rates are determined using historical investments on the transmission system that are already in operation. Any avoided transmission capacity cost that DERs provide would be in the offset of future investment or upgrade needs which is proven to be zero based on the study attached as Exhibit BJM-3 to my testimony.

CONCLUSION

Q. Do you have a recommendation for the Commission?

A. Yes, I recommend that the Companies' forecasted miscellaneous transmission expenses be approved as proposed and that the Companies' filed position for NMS-2 export rates be approved.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Elizabeth J. McFarland**, being duly sworn, deposes and says that she is Vice President, Transmission for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Elizabeth J. McFarland

Elizabeth J. McFarland

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of September 2025.

Kimberly C Bruck

Notary Public

Notary Public ID No. KYNP14646

My Commission Expires:

10-16-2028