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
MICHAEL E. HORNUNG
MANAGER, PRICING/TARIFFS
ON BEHALF OF
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: September 30, 2025

TABLE OF CONTENTS

-INTRODUCTION

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

A. My name is Michael E. Hornung. I am a Manager of Pricing/Tariffs for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies") and an employee of LG&E and KU Services Company. My business address is 2701 Eastpoint Parkway, Louisville, Kentucky 40223.

Q. What is the purpose of your rebuttal testimony?

A. I rebut a number of different arguments and assertions by various intervenors' witnesses. First, I rebut testimony by Joint Intervenors witness James Fine and Sierra Club witness Jeremy I. Fisher concerning a number of issues regarding the Companies' proposed Extremely High Load Factor ("Rate EHLF") standard rate schedule. Second, I explain why, contrary to the arguments of Mr. Fine and Kentucky Solar Industries Association, Inc. witness Jason W. Hoyle, there is no need to address in these proceedings the criteria for closing the Companies' Rider NMS-2 net metering schedules, and I address a number of other Rider NMS-2-related arguments. Third, I rebut Mr. Hoyle and explain why the Companies' proposed qualifying facility ("QF") related tariff revisions are reasonable. Fourth, I address the testimony of Walmart witness Lisa Perry concerning her proposal to require the Companies to collaborate with Walmart and others to develop a new electric vehicle ("EV") charger rate. Fifth and finally, I address the testimony of Kentucky Broadband and Cable Association witness Patricia D. Kravtin concerning the Companies' proposed Rate PSA pole attachment rates.

THE COMPANIES' PROPOSED RATE EHLF REMAINS REASONABLE AS FILED, SUBJECT TO THE MODIFICATION SPECIFIED IN THE CPCN CASE STIPULATION

Q. Do you have any overarching comments concerning intervenor testimony on the Companies' proposed Rate EHLF?

A. Yes. Importantly, all intervenor testimony concerning Rate EHLF supports it, at least in concept. AG-KIUC witness Lane Kollen expressly supports it as proposed, subject to the modification stipulated in Case No. 2025-00045, namely that Rate EHLF apply only to new customers, not existing customer loads;[1] it is a modification the Companies fully support and ask the Commission to require in its final order in these cases. Walmart witness Lisa Perry also supports Rate EHLF as proposed.[2] Sierra Club witness Jeremy Fisher also supports it, albeit with certain proposed revisions the Companies do not support, which I address below.[3] Finally, Joint Intervenors witness James Fine agrees with the need for Rate EHLF, though he would essentially rewrite it wholesale.[4]

Q. How do you respond to assertions by Messrs. Fisher and Fine that the proposed 100 MVA and 85% load factor eligibility thresholds for Rate EHLF are too high?[5]

A. The Companies' 100 MVA demand threshold is reasonable; a lower threshold could encompass too many customers who do not have the same potential planning and financial impacts as the large, high load factor customers the Companies intended

[1] Kollen at 96.
[2] Perry at 6.
[3] Fisher at 5-22.
[4] Fine at 44-58.
[5] Fisher at 6, 7-10, and 12-14; Fine at 45-52.

Rate EHLF to address. The purpose of the rate is to address large, impactful customers of the kind not currently taking service from the Companies. As I explained in my direct testimony, because any one or just a few such customers could require the Companies to acquire additional generation resources to supply their needs and the needs of existing customers, increased minimum billing demands, extended contract terms, and enhanced collateral requirements are appropriate for such customers, but they are not appropriate for other, lower-demand customers.

Indeed, if there were a need for a Rate EHLF-like rate schedule to address customers with lower demand and load factors than the proposed Rate EHLF, the Companies would likely already have a separate rate schedule for them. Today, the Companies have only one customer on service that would qualify for Rate EHLF, and that customer takes service under a special contract.[6]

Q. Messrs. Fisher and Fine both propose aggregating load to meet Rate EHLF thresholds.[7] Would that be something the Companies could support?

A. No, the Companies cannot support such aggregation. The applicable Commission regulation is clear on this point: "The utility ***shall*** regard each point of delivery as an independent customer and meter the power delivered at each point. Combined meter readings ***shall not*** be taken at separate points …."[8] Although the Commission may permit deviations from the rule,[9] it is unclear why that would be appropriate or necessary here. The Companies have stated they would not allow customers to game their tariffs by attempting to spread what is really a single load across multiple

[6] Companies' Response to Walmart 1-8(a).
[7] Fisher at 6, 10-12; Fine at 45-50.
[8] 807 KAR 5:041 Sec. 9(2) (emphases added). *See also* Companies' Response to JI 2-26.
[9] 807 KAR 5:041 Sec. 22.

locations.[10] For colocation data centers, i.e., multi-building data center campuses where each building has a different tenant, an important reason aggregation would be unnecessary is the built-in portfolio diversity of having multiple entities taking service at the same site, which would tend to decrease the risk that the whole campus would cease to take service.

The limited aggregation permitted to qualify for the Companies' Green Tariff Option #3 does not undermine this position.[11] That aggregation is purely voluntary for customers desiring to qualify to pay a *premium* to obtain renewable energy, and it is strictly limited to that sole purpose.[12] Therefore, it does not inform or serve as precedent for load aggregation generally or for Rate EHLF specifically.

Q. How do you respond to Mr. Fisher's position that Rate EHLF must have a mechanism for renewable energy procurement?[13]

A. Mr. Fisher states that the Companies' existing Solar Share and Green Tariff offerings almost suffice for prospective Rate EHLF customers,[14] but he recommends either:

> 1. Design[ing] a broader version of their Green Tariff for EHLF customers that opens the cap on the scale of renewable energy that can be procured and allows for storage, demand management, and transmission improvements; or
>
> 2. Modify[ing] the Green Tariff provision such that it is available to EHLF customers, opens the cap, and allows for storage, demand management, and transmission improvements.[15]

[10] Companies' Response to Sierra Club 2-3(a).
[11] *Contra* Fisher at 11.
[12] Kentucky Utilities Company P.S.C. No. 20, First Revision of Original Sheet No. 69 ("A Customer with multiple accounts may aggregate those accounts for the sole purpose of meeting the 10 MVA requirement."); Louisville Gas and Electric Company P.S.C. Electric No. 13, First Revision of Original Sheet No. 69 ("A Customer with multiple accounts may aggregate those accounts for the sole purpose of meeting the 10 MVA requirement.").
[13] Fisher at 17-22.
[14] Fisher at 21.
[15] Fisher at 22.

He further recommends allowing Rate EHLF customers to be able to pay for Green Tariff resources in lieu of paying for the Companies' generating resources.[16]

The Companies do not believe Mr. Fisher's suggested Green Tariff changes are necessary for at least two reasons. First, any customer may implement its own behind-the-meter assets, including renewable energy generation and battery energy storage, if they desire. Second, having the Green Tariff does not preclude the Companies from entering into a special contract (with Commission approval) if a Rate EHLF customer desires and the Companies agree to a renewable energy or other arrangement. Therefore, there is no need to modify Rate EHLF or the Green Tariff at this time; the Companies retain all the flexibility they need to accommodate future Rate EHLF customers' reasonable renewable energy goals.

Q. Would the Companies support effectively eliminating the Rate EHLF minimum demand charge ratchet of 80% of contract capacity (by raising it to 100%) and imposing a load flexibility requirement for Rate EHLF as Mr. Fine recommends?[17]

A. No. Regarding the Rate EHLF minimum demand charge ratchet, the Companies have already proposed the most aggressive arrangement on their tariff books for Rate EHLF, and by a considerable margin. Rate EHLF requires the monthly billing demand to be the greater of (1) the maximum measured load in the billing period, (2) the highest measured load in the preceding eleven billing periods, or (3) 80% of the maximum contract capacity. In contrast, Rate RTS has the same requirements for just the base demand charge—though only a 50% of contract capacity provision—

[16] Fisher at 22.
[17] Fine at 46-47.

and minimum billing demands for the intermediate and peak periods of the greater of (1) the maximum measured load in the billing period, (2) 50% of the highest measured load in the preceding eleven billing periods. Rate FLS, which like Rate RTS, has three time-differentiated demand charge periods (base, intermediate, and peak), does have a base demand charge minimum of the customer's contract capacity, but the peak and intermediate demands are billed as the greater of maximum demand in that billing period or 50% of the highest measured load in the preceding 11 billing periods. Importantly, the peak and intermediate demand charges are significantly higher than the base demand charge. Therefore, the proposed Rate EHLF demand charge ratchet is far more aggressive than the ratchets for Rates RTS and FLS, and it is reasonable for Rate EHLF customers' expected service characteristics.

Turning to Mr. Fine's proposed load flexibility requirement, it is more of a suggestion than a proposal; he neither provides any evidence to support a load flexibility requirement nor articulates what such a requirement might be. Although the Companies do not oppose load flexibility and will certainly explore it with Rate EHLF customers as a potential future option, not a service requirement, the Companies do not view it as a substitute for a load factor eligibility criterion for Rate EHLF. Moreover, with only one exception, the Companies' standard rates are for firm power service, not interruptible service; some eligible customers have elected to participate in the Companies' curtailable service riders, but the Companies have not required it of them.

The only exception is Fluctuating Load Service (Rate FLS), under which only one customer has ever taken service, which allows for limited-duration curtailments (no more than ten minutes each on five minutes' notice, with no more than 20 curtailments per month) to address system contingencies resulting from unplanned outages or de-rates of the Companies' generating units.[18] Due to its limitations, this curtailability, though useful in system operations to address acute system contingencies, has no explicit effect on generation planning. It therefore does not serve as a useful precedent for serving very large, high load factor customers

In sum, the Companies are open to exploring *voluntary* load flexibility with Rate EHLF customers, but that should have no effect on the Rate EHLF minimum demand charge ratchet.

Q. Why is the Companies' proposed Rate EHLF contract term reasonable despite Messrs. Fisher's and Fine's arguments that it should be longer?[19]

A. The proposed 15-year initial term for a retail electric service agreement under Rate EHLF is reasonable and does not require the addition of a ramp period. The Companies' 15-year contract term compares favorably to the contract terms listed in Mr. Fisher's Table JIF-1, notably exceeds the 12-year term—inclusive of a four-year ramp period—recently approved for AEP Ohio.[20]

Moreover, there is no need for a ramp period; it is not in data center customers' interests to *plan* to prolong unnecessarily their ramp periods. When a Rate EHLF customer signs a retail electric service agreement, it will include a ramp schedule, as large customer contracts typically do. That ramp schedule's demand milestones will be the customer's contract demands for minimum demand charge

[18] Kentucky Utilities Company P.S.C. No. 20, Original Sheet No. 30.3.
[19] Fisher at 6, 14-17; Fine at 53-55.
[20] Fisher at 8.

purposes. In the data center world, where speed to market is key, there is no reason to expect such customers would seek to prolong unnecessarily the ramp period.

The Companies' own experience with prospective data center customers shows this to be true. The Companies' engineering, procurement, and construction agreement with the Camp Ground Road data center project sets out demand milestones that would have the data center campus at a full 525 MW of demand within four years of the first data center building taking service. Considering the ramp periods listed in Table JIF-1, the Companies' experience appears to be consistent with ramp period constraints, again suggesting constraints are unnecessary.

Finally, there is the practical matter that imposing ever more onerous terms on prospective customers will likely drive them away. The Companies understand and agree with the need to protect all customers by having an adequate and appropriate initial term for customers of such magnitude, but their 15-year Rate EHLF contract term is already longer than what most of the utility tariffs Mr. Fisher lists in Table JIF-1 require. Thus, to avoid repelling the very customers the Companies proposed Rate EHLF is designed to serve, the Commission should not require an additional ramp period beyond the proposed 15-year contract term.

Q. Are the Companies' proposed Rate EHLF collateral requirements sufficient?

A. Yes. The only intervenor witness who suggested Rate EHLF's collateral requirements might be insufficient is Mr. Fine, who agrees with the Companies' Rate EHLF exit fee definition, but he asserts the collateral requirement "could be strengthened."[21] Mr. Fine suggests that AEP Ohio's collateral requirement of "50% of the customer's total minimum charges for the full term of the contract [would be] a more protective approach to collateral than proposed by the Companies."[22] Mr. Fine omits that the AEP Ohio data center tariff provisions do not include generation cost because Ohio is a retail choice state,[23] making the posting of "50% of the customer's total minimum charges for the full term of the contract" much less burdensome to the customer than would be a comparable requirement for a Rate EHLF customer. In short, all Mr. Fine provides to support his position is the bare assertion that the collateral requirement "could be strengthened" and a citation to another utility's tariff provision that, in this important respect, is not reasonably comparable to Rate EHLF. The Commission should therefore disregard this argument.

Q. Messrs. Fisher and Fine argue the Companies have not properly addressed cost allocation issues concerning Rate EHLF,[24] and Mr. Fisher asks the Commission to require the Companies to file a cost of service study and an analysis of other means of avoiding potential cost-shifting from Rate EHLF customer to other

---

[21] Fine at 55.
[22] Fine at 55.
[23] *See, e.g., Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers*, Case No. 24-508-EL-ATA, Direct Testimony of Matthew S. McKenzie at 26-27 (May 13, 2024) ("Under the proposed Schedule DCP and Schedule MDC/FLT (discussed in greater detail below), customers may shop for generation supply service from a competitive retail electric supply ("CRES") provider. AEP Ohio expects that all data center customers will choose to be supplied by a CRES provider. If, however, a customer served under Schedules DCP or MDC/FLT elects not to shop, AEP Ohio proposes to conduct a special SSO auction for data center customers. … AEP Ohio proposes to conduct a separate SSO auction for data centers because including data center load in the regular SSO auction could add unacceptable risk and complications for participating suppliers, thus increasing prices for all SSO customers."), available at https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A24E13B43247C00950.
[24] Fisher at 22-27; Fine at 53-58.

customers,[25] while Mr. Fine asks the Commission to open a new proceeding on Rate EHLF-related cost causation "as soon as possible."[26] How do you respond?

A. Though all of these topics are reasonable to discuss at the appropriate time, that time is not now or "as soon as possible." The Companies currently have no Rate EHLF customers, and the Companies' forecast test year data includes no Rate EHLF customers or related revenue and costs; the Companies' base rates, when set following these proceedings, will not change due to Rate EHLF customer effects until *after* the Commission approves new rates in later base rate cases, which will include new cost of service studies to allocate appropriate costs to the Rate EHLF customer class. Thus, the time to address these matters is in those future base rate cases when they will affect customers' rates, not in these cases or in a new cost-causation proceeding to be opened "as soon as possible."

On a related topic, Mr. Fine asserts the minimum demand charge ratchet of 80% is too low for Rate EHLF;[27] I disagree. The Companies' monthly minimum demand charge of 80% of contract demand applicable during each billing period is appropriate for a rate schedule with an 85% *average* monthly load factor eligibility requirement; one would expect a degree of month-to-month variation around the 85% average monthly load factor, and the 80% minimum contract demand charge provides a reasonable floor for that variation. Moreover, it is important to bear in mind that the minimum billing demand in any given billing period for a Rate EHLF customer is (1) the maximum measured demand in that billing period, (2) the highest measured

[25] Fisher at 27.
[26] Fine at 57-58.
[27] Fine at 54-55.

demand in the previous eleven billing periods, or (3) 80% of the contract capacity then applicable, *whichever is highest*. Thus, a Rate EHLF customer should nearly always have a monthly billing demand higher than 80% of the then-applicable contract capacity, and there is no clear reason to change the minimum billing demand ratchet *before there is a single Rate EHLF customer*; again, this is a topic appropriate to address in future base rate cases, not here.

THERE IS NO NEED TO ADDRESS IN THESE PROCEEDINGS THE CRITERIA FOR CLOSING THE COMPANIES' RIDER NMS-2 SCHEDULES, AND THE COMPANIES' PROPOSED RIDER NMS-2 RATES AND THEIR UNDERLYING COMPONENTS ARE REASONABLE

Q. Messrs. Hoyle and Fine offer a number of arguments about the appropriate standards to use when evaluating whether the Companies have reached the 1% net metering capacity level set out in KRS 278.466(1) and whether it would be appropriate for the Companies to cease offering Rider NMS-2 service to new customers at that point.[28] Are these arguments premature?

A. Yes. The Companies are not proposing to close Rider NMS-2 in this proceeding. All we have proposed to do is add text to the Companies' tariffs that alerts customers of the Companies' intention to seek Commission approval to close the Rider NMS-2 tariffs at some point after reaching the statutory threshold. As I stated in my direct testimony, "This addition is purely to provide customers notice of the anticipated closing of the rider to new customers[.]"[29] The Companies anticipate there will be a Commission proceeding to address issues like those Messrs. Hoyle and Fine raise when the Companies make the necessary filings with the Commission at some point

[28] Hoyle at 4-6, 37-41, 53-54; Fine at 41-44.
[29] Hornung Direct at 19.

in the future; the Commission does not have to decide them now, and it is premature to do so.

Q. Mr. Hoyle asserts that the Companies Rider NMS-2 rates should account for renewable generators plus battery energy storage, not just renewable generation.[30] Is Mr. Hoyle mistaken?

A. Yes. Kentucky's net metering statutes clearly state what qualifies as an eligible electric generating facility, and it includes only facilities that generate electricity using solar, wind, biomass, biogas, or hydro energy;[31] nowhere does it mention energy storage of any kind. Following the statutory definition, the Companies' Rider NMS-2 also does not address or compensate energy storage.

This does not mean the Companies do not recognize the possible value of distributed energy resources, including storage, they can both monitor and control, as Mr. Waldrab addressed in his direct testimony.[32] Indeed, the Companies are planning to develop a Bring Your Own Device – Batteries pilot program to explore this potential. But a program of that kind, not Rider NMS-2 rates, would the appropriate way to compensate customers with energy storage who are willing to allow the Companies to monitor and control those resources.

Q. Why would it be inappropriate to retain all existing Rider NMS-2 avoided cost components and use recalculated current values as Mr. Hoyle proposes?[33]

A. The Companies have provided significant additional evidence in these cases of what their actual avoided costs are—and are not—related to Rider NMS-2 customers. It

[30] Hoyle at 4-6, 41, 50-51, 54-56, 57.
[31] KRS 278.465(2)(b).
[32] Waldrab Direct at 41.
[33] Hoyle at 57.

would be inappropriate to overlook that evidence and instead retain "recalculated" existing values of Rider NMS-2 rate components. Moreover, as Mr. Conroy observes in his rebuttal testimony, one reason not to simply retain existing components is that there have been no identifiable transmission, distribution, carbon, or ancillary service cost savings created by Rider NMS-2 customers, notwithstanding that all customers have been paying NMS-2 customers rates that assumed such avoided costs for four years. Simply retaining existing "recalculated" Rider NMS-2 components would require all customers to continue to pay Rider NMS-2 customers for avoided costs the Companies have not actually avoided and have no reason to expect they will. The Commission should therefore reject this proposal.

Q. Although no intervenor witness proposes a value for a jobs benefit component of Rider NMS-2, Messrs. Hoyle and Fine both argue for the existence of one.[34] How do you respond?

A. What I stated in my direct testimony concerning a "jobs benefits" component remains true and is my response to the testimony of Messrs. Hoyle and Fine: The Commission recently approved net metering rates for Duke Energy Kentucky that did not include a jobs benefit component, which Duke argued should be zero because the Commission lacks jurisdiction over such non-energy benefits.[35] Indeed, the Commission repeatedly stated it lacked jurisdiction over such matters for at least a decade:

---

[34] Hoyle at 53; Fine Exh. JF-2.

[35] *Electronic Application of Duke Energy Kentucky, Inc. for an Adjustment to Rider NM Rates and for Tariff Approval*, Case No. 2023-00413, Order at 13 and 43-44 (Ky. PSC Oct. 11, 2024), *rehearing denied* Case No. 2023-00413, Order at 9 and 12 (Ky. PSC Nov. 20, 2024).

- "Notably absent from the Commission's jurisdiction are environmental concerns, which are the responsibility of other agencies within Kentucky state government."[36]
- "[I]ssues of environmental externalities, such as air and water pollution from generating electricity and mining fuel to supply the generating plants, are all issues beyond the scope of the Commission's jurisdiction."[37]
- "The Commission has no jurisdiction over environmental impacts, health, or other non-energy factors that do not affect rates or service. Lacking jurisdiction over these non-energy factors, the Commission has no authority to require a utility to include such factors in benefit-cost analyses of DSM programs."[38]

The Companies acknowledge the Commission took a different view in the Companies' and Kentucky Power Company's 2020 rate cases, though it is unclear what changed to expand the Commission's jurisdiction between October 2018, when the Commission made the last statement quoted above, and mid-2021, when the Commission issued the relevant rate case orders.[39]

---

[36] *The 2008 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2008-00148, Order at 5-6 (PSC Ky. July 18, 2008).
[37] *The 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2011-00140, Order at 4 (Ky. PSC July 8, 2011).
[38] *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441, Order at 28-29 (Ky. PSC Oct. 5, 2018).
[39] *Electronic Application of Kentucky Power Company for (1) a General Adjustment of Its Rates for Electric Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) Approval of a Certificate of Public Convenience and Necessity; and (5) All Other Required Approvals and Relief*, Case No. 2020-00174, Order (Ky. PSC May 14, 2021); *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00349, Order (Ky. PSC Sept. 24, 2021); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and*

THE COMPANIES' PROPOSED QF TARIFF REVISIONS ARE CONSISTENT WITH THE COMMISSION'S QF REGULATION, AND IT WOULD BE INAPPROPRIATE TO ADD NEW AVOIDED COST COMPONENTS TO RIDER SQF

Q. Why is it appropriate for the Companies not to offer to enter into power purchase agreements ("PPAs") with behind-the-meter ("BTM") QFs?

A. Contrary to Mr. Hoyle's arguments, it would serve no purpose to have PPAs for BTM QFs.[40] A BTM QF can provide only as-available energy; only when and insofar as the QF produces energy in excess of the QF customer's needs can energy flow onto the Companies' grid. Under the Commission' QF regulation, purchase rates for as-available energy "shall be based on the purchasing utility's avoided energy costs estimated at time of delivery."[41] A PPA for any such customer would serve no purpose; all it would state is that the Companies would purchase energy from the BTM QF at the Companies' then-effective tariffed rates for such purchases. Thus, it is appropriate for the Companies not to offer to enter into PPAs with BTM QFs.

Q. Do you agree with the Rebuttal Testimony of Charles R. Schram that BTM QFs should not receive capacity payments?[42]

A. Yes, though for different reasons; I defer to Mr. Schram concerning how and when utilities make capacity payments in utility-scale capacity acquisition contexts. But I would note that not providing capacity compensation to BTM QFs is consistent with and symmetrical to the Commission's position that the Companies cannot provide

Gas Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit, Case No. 2020-00350, Order (Ky. PSC Sept. 24, 2021).

[40] *See* Hoyle at 4-6, 24-29.

[41] 807 KAR 5:054 Sec. 7(2)(a).

[42] Hoyle at 4-6.

Green Tariff customers demand charge credits,[43] and it is consistent with the operation of the Companies' Solar Share Program.[44] In both of those programs, participating customers pay the full cost of the relevant solar resources, but they do not receive demand charge offsets, i.e., no capacity compensation.

Q. Is it reasonable to separate QF PPA contract duration from pricing duration as Mr. Hoyle proposes?[45]

A. No, and such a bifurcation of terms is not something the Commission's QF regulation allows or contemplates.[46] Under the Commission's regulation, a QF seeking a PPA may choose "either avoided costs at the time of delivery or avoided costs at the time the legally enforceable obligation is incurred";[47] this means that a QF chooses a pricing methodology at the beginning of the contract term and that methodology does not change for the duration of the contract.

That being said, the Companies recognize the financing difficulty Mr. Hoyle raises concerning contract terms of only seven years. Indeed, that is why the Companies proposed 20-year terms for QF PPAs in their 2020 base rate cases.[48] And the Companies are willing to entertain longer-term PPAs for buy-all, sell-all QFs (i.e.,

---

[43] *Electronic Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source Under Green Tariff Option #3*, Case No. 2020-00016, Order at 21-22 (Ky. PSC May 8, 2020).

[44] Kentucky Utilities Company P.S.C. No. 20, First Revision of Original Sheet No. 72; Louisville Gas and Electric Company P.S.C. Electric No. 13, First Revision of Original Sheet No. 72.

[45] Hoyle at 4-6, 29-32, 57.

[46] 807 KAR 5:054 Sec. 7(2)(b).

[47] 807 KAR 5:054 Sec. 7(2)(b).

[48] *See, e.g.,* Case No. 2020-00349, Order at 10 (Ky. PSC Sept. 24, 2021); Case No. 2020-00350, Order at 10 (Ky. PSC Sept. 24, 2021).

not BTM QFs) on a case-by-case basis, which is appropriate and permissible under the Commission's QF regulation.[49]

Q. Mr. Hoyle argues the Companies' proposed liability-exemption expansion is unreasonable.[50] How do you respond?

A. The goal of the Companies' proposal is to reduce costs associated with liability risk, which is a benefit to all customers. The more liability risk the Companies have, the more risk mitigation costs they will incur (e.g., higher insurance premiums). Therefore, the Companies believe their liability-limitation proposals are reasonable.

Q. Mr. Hoyle argues for QF capacity credits sufficient to allow QF owners to recover their full resource costs.[51] Is that an appropriate basis for establishing QF capacity rates?

A. No. The Commission's QF regulation clearly states that a utility's avoided costs, not what would make QF owners whole, are the appropriate and sole basis for setting QF capacity rates.[52] Thus, Mr. Hoyle's contentions on this issue have no merit.

Q. Would it be appropriate, as Mr. Hoyle argues, to include avoided transmission capacity, distribution capacity, and ancillary services costs in the Companies' Rider SQF rates.[53]

A. No. Again, the Commission's QF regulation clearly states what QF rates should include, and they are limited to avoided energy costs, avoided generation capacity costs, and line loss savings.[54] As Mr. Schram's direct testimony showed, the

[49] 807 KAR 5:054 Sec. 7(4) and (9).
[50] Hoyle at 32-33.
[51] Hoyle at 4-6, 11-16.
[52] 807 KAR 5:054 Sec. 7(2), (4), and (5).
[53] Hoyle at 4-6, 41.
[54] 807 KAR 5:054 Sec. Sec. 7(2), (4), and (5).

Companies' proposed QF rates, including their SQF rates, fully account for these items. It would therefore be inappropriate to follow Mr. Hoyle's recommendation to include avoided transmission capacity, distribution capacity, and ancillary services costs in the Companies' Rider SQF rates.

<u>THERE IS NO COST-OF-SERVICE BASIS FOR NEW EV CHARGER RATES</u>

Q. How do you respond to Ms. Perry's request that the Commission require the Companies "to work with interested stakeholders to develop a new EV rate specifically for public-facing EV chargers and to either seek Commission approval of such rate or provide an update on the stakeholder process within six months following the issuance of a Final Order in this case"?[55]

A. Ms. Perry provides no cost-based justification for the rate she proposes the Commission compel the Companies to develop. Importantly, the Commission has stated it does not have jurisdiction over the rates EV charger owners charge to their customers;[56] if Walmart is not charging customers a sufficient amount to recoup its EV charger-related costs, it is free to change its prices. But there is no evidence in the record of this case to support a different rate or rates for the Companies to serve EV chargers; Walmart did not ask for or provide any. The Commission should therefore disregard this request.

---

[55] Perry at 28-31.

[56] *Electronic Investigation of Commission Jurisdiction over Electric Vehicle Charging Stations*, Case No. 2018-00372, Order (Ky. PSC June 14, 2019).

THE COMPANIES' RATE PSA POLE ATTACHMENT CHARGES ARE REASONABLE AND CONSISTENT WITH THE REQUIREMENTS OF THE COMMISSION'S SEMINAL ORDER IN ADMINISTRATIVE CASE NO. 251

Q. Is it reasonable and consistent with past Commission-approved practice to formulate pole attachment rates on a combined-Companies basis?[57]

A. Yes, and the Companies have used a combined rate for over a decade.[58] Indeed, what appears to be the predecessor organization to the KBCA, the Kentucky Cable Telecommunications Association ("KCTA"),[59] was a signatory to the settlement agreement in the Companies' 2014 base rate cases, which resulted in having the same pole attachment rates for both Companies.[60] Notably, the Companies had proposed *different* pole attachment rates for LG&E and KU in those cases.[61] Also, the KCTA entered into a stipulation with the Companies in their 2016 base rate cases, which resulted in the PSA rates the Companies have today, which are the same for both Companies.[62] It is therefore unclear why this long-established and Commission-approved arrangement—to which what appears to be KBCA's predecessor organization twice explicitly agreed—should now change.

---

[57] *See* Kravtin at 8-11.

[58] *See Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2014-00371, Order Appx. A (Ky. PSC June 30, 2015); *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2014-00372, Order Appx. A (Ky. PSC June 30, 2015).

[59] Charter Communications was a member of the KCTA and is a member of the KBCA, and the two entities used the same Washington, D.C. law firm in proceedings before the Commission.

[60] Case No. 2014-00371, Order Appx. A (Ky. PSC June 30, 2015); Case No. 2014-00372, Order Appx. A (Ky. PSC June 30, 2015).

[61] Case No. 2014-00371, Settlement Testimony of Kent W. Blake Exh. 1, Settlement Agreement, Settlement Exh. 4, KU Tariff, Kentucky Utilities Company P.S.C. No. 17, Original Sheet No. 40 (Apr. 20, 2015) (showing KU's proposed attachment charge of $9.69 and the settled rate of $7.25); Case No. 2014-00372, Settlement Testimony of Kent W. Blake Exh. 1, Settlement Agreement, Settlement Exh. 5, LG&E Electric Tariff, Louisville Gas and Electric Company P.S.C. Electric No. 10, Original Sheet No. 40 (Apr. 20, 2015) (showing LG&E's proposed attachment charge of $9.11 and the settled rate of $7.25).

[62] *Application of Kentucky Utilities Company For an Adjustment of Its Electric Rates and For Certificates of Public Convenience and Necessity*, Case No. 2016-00370, Order Appx. A (Ky. PSC June 22, 2017); *Application of Louisville Gas and Electric Company For An Adjustment of Its Electric and Gas Rates and For Certificates of Public Convenience and Necessity,* Case No. 2016-00371, Order Appx. A (Ky. PSC June 22, 2017).

Q. Ms. Kravtin argues against use of forecast data for establishing Rate PSA rates.[63] How do you respond?

A. First, contrary to Ms. Kravtin's assertions, use of forecast data is entirely consistent with embedded cost ratemaking. Moreover, the Commission's regulations expressly provide for a fully forecasted test year methodology and the Companies have utilized that methodology in all of their rate cases since 2014. There is nothing improper about using forecast data to establish pole attachment rates in the same manner as used for establishing all other rates.

Second, the Companies' net plant calculations are based on historical costs through January 31, 2025, not projections; only the Companies' expenses are forecasts for Rate PSA purposes. The Companies' use of forecast data is reasonable per se for the reason given above, but it is perhaps particularly reasonable for setting Rate PSA rates, which have not changed for the Companies for over ten years and might not change again for years to come.

Third, I would observe that there is nothing about the concept of embedded costs that precludes using forecast data; it is not, as Ms. Kravtin asserts, an "oxymoron" to speak of forecast embedded costs.[64] Ms. Kravtin's testimony cites the Companies' response to KBCA 2-3 that addressed this issue but ignores what the Companies actually said and the Companies' citation to and quotation of the NARUC Electric Utility Cost Allocation Manual.[65] That she does so is understandable; the NARUC manual states conclusively that embedded costs stand in contradistinction

[63] Kravtin at 11-15.
[64] Kravtin at 15.
[65] Kravtin at 14-15.

to marginal costs, not forecast costs, and explicitly says embedded costs can be forecast:

> It is important to note that the difference between an embedded cost of service study and a marginal cost of service study lies in their different concepts of cost. The embedded cost study uses the accounting costs on the company's books during the test year as the basis for the study. In contrast, the marginal cost study estimates the resource costs of the utility in providing the last unit of production.
>
> …
>
> Embedded cost studies rely on the company's historical records or projections of these records, whose accuracy can be audited and verified either at the time of filing *or at the end of the period projected*.[66]

In any event, the Commission's order in Administrative Case No. 251 does not specifically require the use of embedded costs for determining the annual carrying charge (i.e., the annual expense of owning a pole) component of the pole attachment rate. So, to the extent Ms. Kravtin equates "embedded costs" with "historical costs," that limitation does not exist with respect to expenses. And as explained above, the net plant calculations (including but not limited to bare pole cost) *are* based on historical costs. Therefore, the Companies' use of forecast data in setting Rate PSA rate was and is entirely consistent with an embedded cost methodology.

Q. How do you respond to Ms. Kravtin's assertion that the rates of return the Commission should apply for setting Rate PSA rates are the rate of return from the Companies' 2020 base rate cases rather than the rates of return established in these cases?[67]

[66] NARUC Electric Utility Cost Allocation Manual at 15 and 17 (Jan. 1992) (emphasis added).
[67] Kravtin at 15.

A. Ms. Kravtin's assertion misunderstands the Commission's final order in Administrative Case No. 251.[68] It is true that the order states:

> There should be included in the "cost of money" factor a reasonable amount representing a return on the utility's investment in the poles. For convenience and certainty of computation, the Commission finds that this return should be equal to the return on investment (or margin) allowed in the utility's last rate case.[69]

As is so often the case, context matters. That order required all electric utilities then "providing or proposing to provide CATV pole attachments" to file within 45 days of the order tariffs implementing the order's requirements.[70] Naturally, the Commission did not have time to establish afresh an appropriate rate of return for each affected utility within 45 days solely for the purpose of implementing pole attachment rates, so it stated in its order that the appropriate rate of return to use was the one approved in each utility's most recent rate case. What the Commission did *not* do was create a rule that pole attachment rates set in base rate cases thereafter should always use the rate of return established in the utility's previous rate case, which would be counterintuitive at best. It would be an odd result, indeed, if the rate of return for purposes of determining the Companies' pole attachment rate was different than the rate of return approved in the current cases to establish all other rates. This would mean that retail electric customers would pay a different rate of return than pole attachment customers.

Thus, the Commission should disregard Ms. Kravtin's recommendation as a misunderstanding of the Commission's final order in Administrative Case No. 251.

---

[68] *The Adoption of a Standard Methodology for Establishing Rates for CATV Pole Attachments,* Admin. Case No. 251, Order at 1 (Ky. PSC Sept. 17, 1982).
[69] *Id.* at 12.
[70] *Id.* at 19.

Q. Was the Companies' addition of common plant and cash working capital to embedded costs reasonable for calculating Rate PSA rates?[71]

A. Yes. Ms. Kravtin refers to these as "unsanctioned add-ons" but offers no basis for her contention, which directly contravenes the Commission's order in Administrative Case No. 251:

> Having determined that the CATV operator will be considered a customer of the utility, the Commission finds that such customers should be required to pay their equitable share of *all* the utility's costs in providing service.
>
> CATV operators argue that certain costs of the utility have no relationship to the services provided to them such as directory advertising, insurance and administrative overhead. *However, no classification of utility customers can or should be allowed to pick and choose the categories of expense to which it will be subject.*
>
> The annual carrying charge should be designed to recover the utility's cost in providing service. Items included in this calculation should represent an equitable share of *all* operating and maintenance expenses, taxes, and depreciation, and a cost of money return component. …
>
> …
>
> We find it reasonable to allow a contribution by CATV toward the common costs of the utility which cannot be directly allocated to any particular classification of customer. However, each utility which includes such a contribution in its rate development must provide justification for the amount of such contribution which it proposes to include.[72]

Common plant and cash working capital are common costs of the Companies, which are not recovered elsewhere in the pole attachment rate formula, and it is appropriate to recover an equitable share of such costs from pole attachment customers, just as

[71] Kravtin 16-17.

[72] Admin. Case No. 251, Order at 11-12 (Ky. PSC Sept. 17, 1982) (emphases added). *See also id.* at Appx. A at 1 ("Bell requested clarification as to whether contribution toward common costs of the utility would be allowed as part of the rate computation. The Commission has allowed such contribution when adequate justification is provided.").

the Commission's longstanding order in Administrative Case No. 251 states. That is what the common plant and cash working capital adders to the net cost rate base are intended to accomplish.

Q. How do you respond to Ms. Kravtin's assertion that Companies used a "novel" blended maintenance and carrying charge factor?[73]

A. To put it plainly, the Companies did not use a "novel" blended maintenance and carrying charge factor; rather, it is the same approach the Companies have used in previous pole attachment charge calculations. Ms. Kravtin also claims the Companies used a prohibited "revenue requirement," but the revenue requirement is really just another way of stating the annual carrying cost of a pole (multiplied by the number of poles). In other words, from an accounting perspective, the way the Companies calculated Rate PSA rates does not greatly differ from how Ms. Kravtin calculated such rates; the nomenclature differs, but not much else. Both approaches are designed to identify the cost of service. By way of example, Ms. Kravtin proposes that the pole maintenance carrying charge rate for the combined Companies should be 2.77%,[74] whereas the Companies' proposed calculations (maintenance revenue requirement divided by net cost rate base) yield a 2.11% rate.

Q. Do you have any other comments on Ms. Kravtin's testimony?

A. Yes. It appears that Ms. Kravtin agrees with the Companies that there should be separate two-user and three-user rates. It further appears that Ms. Kravtin agrees with the Companies' calculations of the "space usage factors" for the two-user and three-user rates. But Ms. Kravtin's proposed pole attachment charges ignore the nature of

[73] Kravtin at 17-18.
[74] Kravtin Exhibit 5.

future test year rate cases and omit costs appropriate to recover through pole attachment charges. Therefore, the Commission should disregard her proposed rates.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Michael E. Hornung**, being duly sworn, deposes and says that he is Manager of Pricing/Tariffs for LG&E and KU Services Company, that he 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 his information, knowledge, and belief.

Michael E. Hornung

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 17th day of September 2025.

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

CAROLINE J. DAVISON
COMM EXPIRES 01/22/2027
NOTARY PUBLIC
ID # KYNP63286
STATE AT LARGE, KENTUCKY