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, 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**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND 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**

JOINT POST-HEARING BRIEF OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

Dated: May 24, 2021

TABLE OF CONTENTS

INTRODUCTION

Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies") submit this brief and request the Kentucky Public Service Commission ("Commission") issue an order by June 30, 2021 approving the proposed rates, terms, and conditions set forth in the tariffs and granting the certificates of public convenience and necessity submitted with the parties' Stipulation and Recommendation.[1]

In the course of preparing their applications in 2020, due to the pandemic, the Companies delayed the filing of their applications two months from the timing previously planned so that the effective date of the base rate changes will occur in July 2021, when many in September 2020 believed the economy would be well on the way to rebounding.[2] The Companies also took several steps to moderate their requests and thus address the rate impact to customers, reducing the filed revenue requirement increase by a total of $54.1 million.[3]

On November 25, 2020, KU and LG&E filed base rate applications supported by fully forecasted test periods ending June 30, 2022 and base periods ending February 28, 2021.[4] In their applications, KU sought a $170.1 million increase in electric revenue requirements; LG&E sought a $131.1 million increase in electric revenue requirements and a $30.0 million increase in gas revenue requirements.[5] The Companies further requested certificates of public convenience and

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[1] *Stipulation and Recommendation* (filed on April 19, 2021), Stipulation Exhibit 5 (KU Tariff), Stipulation Exhibit 6 (LG&E Electric Tariff), and Stipulation Exhibit 7 (LG&E Gas Tariff). As expressly recognized in Section 5.8, two issues are reserved for the hearing: Companies' net metering proposals (Riders NMS-1 and NMS-2) and qualifying facility tariff provisions (Riders SQF and LQF).

[2] Testimony of Paul W. Thompson at 21. Indeed, this belief, in fact, is proving to be the case. See e.g, Executive Order No. 2021-326, State of Emergency, issued May 13, 2021, by Gov. Andy Beshear.

[3] Testimony of Kent W. Blake at 4-6. For example, the Companies chose not to request the increases recommended by Mr. Spanos for depreciation rates for electric and gas distribution, transmission, and common plant asset classes. The Companies also used a five-year historical average (2015-2019) of bad debt, which obviously did not include any impacts from the COVID 19 pandemic.

[4] KRS 278.190(1), (2); 807 KAR 5:001 Section 16(1)(a)2.

[5] KU Application, ¶ 6; LG&E Application, ¶ ¶ 6 and 8; Companies' Supplemental Responses to Commission Staff's First Request for Information, No. 56 (filed Feb. 26, 2021).

necessity ("CPCNs") to deploy Advanced Metering Infrastructure ("AMI") systems and related regulatory deferral accounting authority. KU and LG&E also proposed a one-year $53.5 million Economic Relief Surcredit to temper the impact of the base rate changes until the middle of 2022 when many economists were projecting a full return to a pre-COVID economy.[6] On December 9, 2020, the Commission issued orders in both cases suspending the proposed changes in base rates for six months or up to and including June 30, 2021.

The Commission, granted intervention to 13 parties in one or both proceedings: the Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention ("AG"); United States Department of Defense and All Other Federal Executive Agencies ("DoD"); Kentuckians for the Commonwealth ("KFTC"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky Solar Energy Society ("KYSES"); Kentucky Solar Industries Association, Inc. ("KYSEIA"); The Kroger Company ("Kroger"); Lexington-Fayette Urban County Government ("LFUCG"); Louisville/Jefferson County Metro Government ("Louisville Metro"); Mountain Association ("MA"); Metropolitan Housing Coalition ("MHC"); Sierra Club; and Walmart Inc. ("Walmart"). Each participated in one or both of the proceedings.

On March 5, 2021, after three rounds of discovery, the intervenors filed their testimony. On April 12, 2021, following a round of discovery, the Companies filed their rebuttal testimony.

The Commission Staff, and all of the parties, participated in an informal conference on April 15 and 16, 2021. On April 19, 2021, all of the parties (collectively the "Stipulating Parties"), entered into and filed a *Stipulation and Recommendation* ("Stipulation).[7] The Stipulation, with two exceptions, is a unanimous settlement between the Companies and the 13 parties who represent every customer rate class and a wide range of diverse interests. The Stipulation is a

[6] KU Application, ¶ 15; LG&E Application, ¶ 13.
[7] On May 7, 2021, the Companies filed a *Joint Errata to Stipulation Exhibit 1, Depreciation Rates*.

unanimous, comprehensive written agreement that recommends with two exceptions fair, just, and reasonable resolutions of all the issues in these cases.[8]

On April 26 through April 28, 2021, the Commission held a hearing, and received evidence in the form of testimony from all the parties and the Stipulation. On May 3, 2021, the Commission issued an order permitting one round of post-hearing data requests, establishing a briefing schedule and directing the case to stand submitted for a decision on June 2, 2021.[9]

ARGUMENT

I. Stipulation and Recommendation

The Stipulation, entered into between the Companies and all 13 intervening parties, reflects a reasonable disposition of the issues, including a 34 percent reduction in the total revenue requirements, consensus on revenue allocations, rate design, and terms and conditions of service, and agreement on the public convenience and necessity for AMI systems and their associated ratemaking treatment. In addition, the Stipulation provides important and valuable consideration that cannot be achieved through litigation of these cases including:

a. commitments by the Companies not to seek to have new base rates put into effect prior to July 1, 2025 (though they may file base rate applications in calendar year 2024 if the rates will not go into effect prior to July 1, 2025),[10]

b. increased shareholder contributions to low-income customers,[11]

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[8] The Stipulation, as expressly recognized in Section 5.8, reserved two issues for the hearing: Companies' net metering proposals (Riders NMS-1 and NMS-2) and qualifying facility tariff provisions (Riders SQF and LQF).
[9] The Commission's May 3, 2021 Order expressly noted that the issues pertaining to the cogeneration tariff and net metering issues were reserved for further discovery and potentially a second hearing.
[10] Stipulation, Article I, Section 1.1, subject to Stay-Out Exceptions in Section 1.2.
[11] Stipulation, Article V, Section 5.7 Low-Income Assistance ("The Utilities' current annual shareholder contributions for low-income assistance (i.e., contributions to Association of Community Ministries, Inc. ("ACM"), Home Energy Assistance ("HEA"), and Wintercare) will be increased by the same percentages as the overall increases in revenue requirements resulting from these proceedings.").

c. and consideration of possible customer programs.[12]

For all these reasons, the Commission should afford great weight to the Stipulation when deciding these cases.

A. Overview

The record shows that the parties had various positions on a wide range of issues. As Mr. Blake discussed in his testimony, during the course of the settlement conference, each party represented its own client's interests and considered the interests of all the Companies' customers as well, which led to the revenue requirements, revenue allocation and rate design proposed in the Stipulation.[13] The parties worked to mitigate the impact on customers to the extent possible, while still providing the Companies an opportunity to recover their costs of providing safe and reliable service. The Stipulation represents a remarkable achievement in complicated cases under challenging conditions given the difficult and sometimes emotionally charged topics.

The Stipulation provides a balanced, detailed, and comprehensive recommendation for the resolution of all revenue requirement issues, and in doing so, presents a transparent calculation of the revenue requirements recommended by the Stipulating Parties. While the Companies, any other party or the Commission could selectively argue for or against a specific adjustment, the fact that all parties with their varying interests, ultimately agree upon the resulting revenue requirements, evidences that the Stipulation results in a fair, just, and reasonable outcome.

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[12] Stipulation, Article V, Sections 5.2(j) and 5.6.
[13] Stipulation Testimony of Kent W. Blake at 3-4.

B. Stipulation Recommended Revenue Requirements are Reasonable

The Stipulation reduces KU's proposed revenue requirement increase by $54.0 million relative to KU's adjusted filed position,[14] for a stipulated increase of $115.9 million;[15] it reduces the proposed revenue requirement increase for LG&E's electric operations by $51.1 million relative to LG&E's adjusted filed position,[16] for a stipulated increase of $77.3 million;[17] and it reduces the proposed revenue requirement increase for LG&E's gas operations by $8.8 million relative to LG&E's adjusted filed position,[18] for a stipulated increase of $24.2 million.[19] In accordance with the Commission's policy, the calculations used to arrive at each stipulated revenue requirement as adjusted from the revenue requirements requested in the applications are clearly set forth in the Stipulation.[20] The calculations include adjustments to depreciation expense and the return on equity and updates to pension expense and the long-term debt rate. The Stipulation further addresses the various possible adjustments to net operating income by recommending that, on balance, except as modified by the Stipulation and its exhibits, the Companies' filed positions should be approved.[21]

1. Depreciation

The largest and perhaps most contentious issue in these cases are the proposed increases to the depreciation rates for Mill Creek Units 1 and 2 and Brown Unit 3. While none of the intervenors contest the calculation of the proposed depreciation rates or dispute the Companies'

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[14] KU Supplemental Response to Commission Staff's First Request for Information, No. 56 (filed Feb. 26, 2021).
[15] Stipulation, Article II, Section 2.1.
[16] LG&E Supplemental Response to Commission Staff's First Request for Information, No. 56 (filed Feb. 26, 2021).
[17] Stipulation, Article II, Section 2.1.
[18] LG&E Supplemental Response to Commission Staff's First Request for Information, No. 56 (filed Feb. 26, 2021).
[19] Stipulation, Article III, Section 3.1.
[20] Stipulation, Article II, Section 2.3, Article III, Section 3.3.
[21] Stipulation, Article V, Section 5.9 ("The Parties recommend to the Commission that, except as modified in this Stipulation and the exhibits attached hereto, all other relief requested in the Utilities' filings in these Rate Proceedings, including without limitation all rates, terms, conditions, certificates of public convenience and necessity, regulatory waivers, and deferral accounting, should be approved as filed or as later corrected or amended by the Utilities in their responses to data requests.").

analysis of the remaining economic lives of these generation units, the intervenors vigorously opposed the increase in depreciation expense as simply being too large under the circumstances. The Stipulation resolves this controversy and recommends that, for the purposes of these proceedings, the stipulated electric revenue requirement increases reflect continuing to use the Companies' currently approved depreciation rates for Mill Creek Units 1 and 2 and Brown Unit 3. The Stipulating Parties further agree that the Commission should approve the Companies' other proposed depreciation rates as filed in the Companies' applications for ratemaking purposes.[22] This adjustment, as well as the associated impact of these depreciation adjustments on the Companies' capitalization and the amortization of excess accumulated deferred income taxes, reduces the Companies' electric revenue requirement increases by $33.0 million for KU and $36.5 million for LG&E.[23]

At the hearing, the Companies' witnesses explained the differences between the Stipulation's depreciation rates when compared to other evidence in the record.[24] Mr. Blake explained the difference between the depreciation rates filed in the direct case and the depreciation rates included in the Stipulation by clarifying that the direct case depreciation rates included changes to the depreciation rates for Mill Creek Unit 1, Mill Creek Unit 2, Brown Unit 3, and other units, as well as the impacts of excess ADIT and the offsetting capitalization effects.[25] He also made clear that AG-KIUC witness Kollen's depreciation adjustments did not address the excess ADIT impacts or the Private Letter Ruling impact.[26] Mr. Garrett explained that the Companies' response to Kroger 2-7 reflects the impact on the revenue requirement of the depreciation rates in

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[22] 4/26/21 Hearing, VR 9:53:15 – 9:58:20 (Blake), 16:12:10 – 16:18:24 (Garrett), VR 16:18:24 (Garrett); *see* Stipulation, Article II, Section 2.2(B).
[23] *See* Rebuttal Testimony of Christopher M. Garrett at Rebuttal Exhibit CMG-7.
[24] A complete set of agreed depreciation rates for the utilities is attached as Stipulation Exhibit 1, as corrected by the May 7, 2021 filing of *Joint Errata to Stipulation Exhibit 1, Depreciation Rates.*
[25] 4/26/21 Hearing, VR 9:53:15 – 9:58:20.
[26] *Id.*

effect prior to these rate case proceedings for all generating units, not just Mill Creek Unit 1, Mill Creek Unit 2, and Brown Unit 3.[27]

In agreeing to the continued use of the Mill Creek Unit 1, Mill Creek Unit 2, and Brown Unit 3 current depreciation rates, the Stipulating Parties recognized that doing so would likely result in significant remaining net book values and uncollected decommissioning costs for these generating assets when they are retired. The Stipulating Parties thus agreed that the Companies should recover and earn a return on the remaining book value, retirement costs, and decommissioning costs of these prudently incurred assets through a Retired Asset Recovery Rider ("RARR").[28] Stipulations Exhibits 8 (KU) and 9 (LG&E) present the RARR mechanism for each utility. As Mr. Blake explained, "[t]his approach helps customers by reducing revenue requirements in the near term while also ensuring recovery of, and a return on, the Companies' prudent investments in these generating facilities."[29]

Once approved, the Companies will make separate filings with the Commission in the future to establish the specific costs to be collected through the charges assessed by these riders. With each retirement, LG&E or KU will make a filing to incorporate the accurate Retirement Costs[30] in the RARR and respond to discovery to provide the Commission with reasonable reporting on the RARR when they begin recovering amounts through it.[31] Under the RARR, the Commission will continue to have authority to review the prudency of amounts to be recovered through the RARR, particularly new capital investments made beyond the test period in this case.[32]

[27] 4/26/21 Hearing, VR 16:12:10.
[28] Stipulation, Article II, Section 5.3.
[29] Stipulation Testimony of Kent W. Blake at 18.
[30] Stipulation, Article V, Section 5.3 (""Retirement Costs" include the net book value, materials and supplies that cannot be used economically at other plants owned by the Utilities, and decommissioning or removal costs and salvage credits, net of related accumulated deferred income tax ("ADIT"). Related ADIT shall include the tax benefits from tax losses.").
[31] 4/26/21 Hearing, VR 9:36:52.
[32] 4/26/21 Hearing, VR 9:40:25; 9:50:41 – 9:53:05.

2. Return on Equity ("ROE")

The Stipulation provides that, for the purposes of these proceedings, a 9.55% ROE is reasonable for the Companies' electric and gas operations.[33] A 9.55% ROE reduces the Companies' adjusted proposed electric revenue requirement increases by $16.7 million for KU and $11.0 million for LG&E and reduces LG&E's adjusted proposed gas revenue requirement increases by $3.4 million.[34] The stipulated ROEs are reasonable for several reasons.

First, the value is consistent with and supported by the record evidence. The Companies presented evidence supporting a 10.0% ROE.[35] AG-KIUC witness Baudino provided ROE testimony recommending a 9.0% ROE[36] and the DoD provided ROE testimony supporting a 9.3% ROE.[37] The stipulated 9.55% ROE fits squarely within this range of recommendations.

Moreover, the record evidence also shows the stipulated ROE is consistent with that being provided to other vertically-integrated utilities according to Regulatory Research Associates, which indicated that the average award for vertically integrated utilities in 2020 was 9.55%.[38] That average award remains consistent with two very recent awarded ROEs to vertically-integrated electric utilities of 9.6%.[39]

Third, the market changes that have occurred since the Commission last authorized a ROE for a vertically-integrated utility, which was in the Kentucky Power proceeding, further support

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[33] Stipulation, Article II, Section 2.2(A); Article III, 3.2.(A). Consistent with the Commission's recent precedent of awarding mechanism ROEs that are 20 basis points below awarded base rate ROEs, the Parties have also agreed that an ROE of 9.35% is appropriate for the Companies' Environmental Cost Recovery and Gas Line Tracker mechanisms. *Id.*

[34] Stipulation Testimony of Kent W. Blake at 8.

[35] Testimony of Adrien M. McKenzie, CFA at Exhibit No. 2.

[36] Direct Testimony and Exhibits of Richard A. Baudino at 3.

[37] Direct Testimony and Exhibits of Christopher C. Walters at 3.

[38] Companies' Response to Commission Staff's Fifth Request for Information, No. 3.

[39] *Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Docket No. E-2, Sub 1219, Order at 91-92 (NC UC Apr. 16, 2021); *Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Docket No. E-7, Sub 1214, Order at 86-97 (NC UC Mar. 31, 2021).

the stipulated ROE. Mr. McKenzie, on behalf of the Companies, presented evidence in his rebuttal testimony demonstrating that Treasury and Utility bond yields increased significantly from November 2020 to April 2021, and further explained that economic forecasters anticipate yields on Treasury securities will continue to increase significantly over the near-term.[40]

Finally, as noted by Mr. Blake, the Stipulating Parties considered the financial risk of the four-year stay-out commitment to the Companies in negotiating the stipulated return on equity.[41]

3. Controversy over Scheduled Plant Outage Expense Resolved

The ratemaking treatment of the Companies' scheduled plant outage expense was also a controversial issue in these proceedings. To resolve this issue in prior cases, the stipulating parties which include many of the Stipulating Parties here, agreed to use a five-year historical average[42] and an eight-year average[43] of generator outage expenses in their revenue requirements pursuant to the stipulations and recommendations reached in the 2018 and 2016 rate cases, respectively. In accordance with these approved stipulations, the Companies also used deferral accounting to record and recover the difference between actual generator outage expenses and the level included in base rates.

In previous cases, and again in the present cases, intervenors expressed concern about the Companies' use of deferral accounting to account for the differences between actual plant outage expenses and those to be embedded in base rates, arguing the treatment did not create enough incentive to control costs. In reaching the Stipulation here, the Companies compromised on this issue. To resolve this matter, the Stipulating Parties agreed to recommend using the Companies'

[40] Rebuttal Testimony of Adrien M. McKenzie, CFA at 14-15.
[41] Stipulation Testimony of Kent W. Blake at 5.
[42] Case Nos. 2018-00294 and 2018-00295, Stipulation and Recommendation, Article I, Section 1.2(F) (Ky. PSC Mar. 1, 2019).
[43] Case Nos. 2016-00370 and 2016-00371, Stipulation and Recommendation, Article II, Section 2.2(F) (Ky. PSC Apr. 19, 2017).

normalized level of plant outage expenses as filed effective with the change in base rates on July 1, 2021 in calculating the Companies' electric revenue requirements.[44] To further resolve this running dispute, the Stipulating Parties agreed to recommend effective July 1, 2021, that the Companies will *not* establish any regulatory assets or liabilities to account for the differences between actual plant outage expenses and those to be embedded in base rates established in these proceedings.[45]

C. Advanced Metering Infrastructure

The Stipulation specifically adopts the Companies' proposal for full deployment of AMI.[46] As Mr. Bellar described in his direct testimony,[47] the Companies' AMI proposal in these cases is vastly different than their prior AMI proposals.[48] The Companies have demonstrated that the current AMI proposal[49] is the most cost-effective means by which to accomplish the critical task of obtaining customer usage data. Under the Companies' cost benefit analysis, full AMI deployment is approximately $53.3 million favorable to the status quo.[50] As Mr. Bellar explained at the hearing: (1) the Companies have proposed AMI because the evidence shows it is the best way to measure consumption in a least-cost manner that is also conducive to customer service goals;[51] and (2) investor interest in AMI exists because investors are interested in companies that can deploy innovative technology in a cost-effective manner.[52]

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[44] Stipulation, Article V, Section 5.1.
[45] *Id.* The regulatory assets and liabilities established prior to these rate proceedings relating to scheduled plant outage expenses will continue to be amortized according to the Commission's past orders.
[46] Stipulation, Article V, Section 5.2.
[47] Testimony of Lonnie E. Bellar at 57-61.
[48] The Companies' most recent AMI proposal prior to the AMI proposal in these cases was made in *Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for Full Deployment of Advanced Metering Systems*, Case No. 2018-00005.
[49] The current proposal is described as "AMI + AMR in Gas-Only Territory" in testimony and in the Companies' cost-benefit analysis at Exhibit LEB-3 of Mr. Bellar's Direct Testimony.
[50] Testimony of Lonnie E. Bellar, Exhibit LEB-3 at 4.
[51] 4/28/21 Hearing, VR 14:04:42.
[52] 4/28/21 Hearing, VR 14:06:40.

Notably, the Companies proposed ratemaking treatment of AMI will attempt to achieve a result under which customers will not see a revenue requirement increase associated with the implementation of AMI.[53] As Mr. Blake explained, the Companies will use the amortization of the regulatory assets and liabilities associated with the AMI project to address the up-front cost of and long-term benefit from the AMI project to try to achieve that outcome.[54]

The cost favorability and proposed ratemaking treatment allowed AG witness Paul Alvarez to opine that the AMI proposal has the potential to "be among the most successful for customers of any in the United States to date."[55] That opinion supports including approval of AMI in the Stipulation, along with the ratemaking proposal that was refined and clarified as described in Article 5.2 of the Stipulation. Of course, all Stipulating Parties agreed that, in approving the AMI ratemaking proposal, the Commission is not foregoing its authority to review the costs, regulatory assets, and regulatory liabilities in future base rate cases or other regulatory proceedings.[56]

D. Allocation and Rate Design

The revenue allocations recommended in the Stipulation are fair, just, and reasonable in the context of the Stipulation as a whole and are worthy of Commission approval.[57] To reach agreement on the stipulated allocations, experienced advocates representing all customer classes worked together using accepted cost-allocation principles to reach equitable allocations and rate designs, which included: (1) the existing subsidy of the Residential Class remains in place as their rates will either increase at the system average increase (KU and LG&E gas rates) or only slightly above the system average increase (LG&E electric rates); (2) the subsidy supported by the

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[53] Testimony of Kent W. Blake at 16; *see also* Exhibits KWB-1 and KWB-2.
[54] *Id.*
[55] Direct Testimony of Paul J. Alvarez at 9.
[56] Stipulation, Article V, Section 5.2(H).
[57] *See* Stipulation Exhibit 2 for stipulated allocations.

industrial rate schedules should be eliminated; (3) the lighting rate schedules generally receive no increases; and (4) the remaining commercial rates receive above average increases. The Stipulation also reflects fundamental ratemaking principles like gradualism and recognizes legitimate differences between customer classes based on the cost of service studies in the record. For example, the revenue allocations between the various commercial and industrial rate classes recognize that large industrial customers face national and often global competition and can choose where to locate, remain, or expand based on important input costs, including energy costs.[58] Commercial customers, on the other hand, tend to locate where people reside regardless of energy costs due to the nature of their businesses. The resulting stipulated revenue allocations therefore ensure that industrial customer classes continue to provide reasonable rates of return while keeping their rates low enough for the Companies' service territories to remain competitive to retain and expand such customers' load, which is a benefit for all customers. In addition, all of the stipulated allocations between such customer classes find support in either the Companies' 6-CP or LOLP cost-of-service studies.[59]

The stipulated rate designs and rates are also fair, just, and reasonable. First, the Stipulation provides that the Companies' residential Basic Service Charges will remain unchanged,[60] which is a compromise position that is reasonable in the context of the entire Stipulation.[61] Second, the stipulated rate designs for the Companies' Rates TODS, TODP, RTS, and FLS, which will collect the allocated revenue increases primarily through demand charges rather than energy charges, are

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[58] *See* 4/27/21 Hearing, VR 17:04:24 – 17:08:36; *see also* Rebuttal Testimony of William Steven Seelye at 107-109.
[59] *See, e.g.,* Rebuttal Testimony of William Steven Seelye, Rebuttal Exhibit WSS-8; *see also* Direct Testimony and Exhibits of Stephen J. Baron at 32.
[60] Stipulation, Article IV, Section 4.3.
[61] The Companies presented cost-of-service evidence in these proceedings to support increasing their current residential Basic Service Charges. *See, e.g.,* Direct Testimony of William Steven Seelye at 16-21. Other parties who addressed residential Basic Service Charges argued against increasing residential Basic Service Charges from their current levels. *See, e.g.,* Direct Testimony of Glenn A. Watkins at 72-88; Direct Testimony of James Owen at 36-41.

likewise reasonable.[62] These stipulated energy charges still exceed the Companies' variable cost of production, so they do not create an energy-cost subsidy for customers on these rates.[63] Also, because the underlying cost increases reflected in rate increases in these proceedings are fixed costs, not variable production costs, it is reasonable and appropriate to increased demand charges for these rate schedules to collect the stipulated revenue increases.

II. Issues in the Direct Case

A. Net Metering

Much has been said in these proceedings concerning the Companies' net metering proposals. Rather than recite all of the relevant arguments and evidence at length, it is helpful to crystalize the handful of truly pertinent issues. Doing so clearly shows that the Companies' proposed Rider NMS-2 is fair, just, and reasonable for *all* customers.

First, Kentucky's recently amended Net Metering Statutes distinguish between the two distinct roles of net metering customers regarding their serving utilities: customer and generator. As a customer, *i.e.*, a consumer of electric service from a serving retail electric supplier, the Net Metering Statutes could not be clearer that (1) a net metering customer must pay the full applicable retail rate(s) for all energy consumed in each billing period and (2) the serving utility has an unambiguous right—but not an obligation—to create separate rates for net metering customers to ensure full cost recovery for serving such customers.[64] Notably, the unrebutted evidence in these proceedings is that the Companies' current net metering customers are receiving significant subsidies and that, even under Rider NMS-2, future net metering customers will likely receive subsidies in their role as customers.[65] But it is equally important to note that the Companies are

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[62] *See* Stipulation Exhibit 5 (stipulated KU tariff); Stipulation Exhibit 6 (stipulated LG&E electric tariff).
[63] *See* 4/27/21 Hearing, VR 17:08:40 – 17:09:48.
[64] KRS 278.465(4)(b); KRS 278.466(5).
[65] *See, e.g.*, Rebuttal Testimony of William Steven Seelye at 67-72.

not proposing to address those subsidies in these proceedings; they are not proposing to create separate net metering rates for future net metering customers as customers. Therefore, any assertion that the Companies' proposed Rider NMS-2 compensation rates lack cost of service evidence is both unsupported and entirely beside the point: cost of service evidence is relevant when setting rates for electric service taken from a utility, not for compensation rates paid to producers for energy they provide.[66]

And regarding that second role, *i.e.*, as a producer of energy onto a retail electric supplier's system, Kentucky's current Net Metering Statutes are not silent; rather, they speak explicitly to that role, requiring that energy produced onto a utility's system by a net metering customer be compensated in the form of a dollar-denominated bill credit for all energy produced onto the utility's system during a billing period.[67] It is only the amount of the rate to be paid to *future* net metering customers—current net metering facilities will keep their current arrangement for 25 years—that is at issue in these proceedings concerning Rider NMS-2.

Kentucky's Net Metering Statutes do not state that the Commission should ensure that net metering customers recover their costs or earn a return on their investments. Indeed, the statutes do not even state a policy goal of encouraging net metering or targeting a minimum amount of net metering capacity in each retail electric supplier's service territory; rather, the General Assembly recently instituted a firm ceiling on the amount of net metering capacity each utility must serve. Thus, arguments concerning net metering customers' return on investment or the projected effect of Rider NMS-2 on future net metering growth find no basis in statute and are directionally contrary to the General Assembly's recent amendments to KRS 278.466(1) to establish a firm ceiling on net metering capacity.

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[66] *See* Rebuttal Testimony of Robert M. Conroy at 5.
[67] KRS 278.466(3) and (4); KRS 278.465(4)(a).

The question before the Commission, therefore, is not what compensation rate for future net metering customers will incentivize growth in such generating facilities; rather, the question is what compensation rate for intermittent, as-available energy that is unsupported by any legally enforceable obligation regarding the net metering customer is fair, just, and reasonable for *all* customers to pay. The Companies believe that rate is already established: it is their avoided production cost of energy as approved by the Commission in Rider SQF. If the Commission were to deviate from that cost, a small adjustment for avoided losses (no more than 6%) might be plausible. But there simply is no evidence for any other increase to the proposed Rider NMS-2 compensation rate: there is no evidence in these proceedings of *any* avoided distribution, transmission, or generation capacity cost resulting from net metering. Moreover, all of the other categories of supposed benefits of net metering that certain intervenors have proposed be included are either benefits directly received by net metering customers (so-called "host benefits") that are unnecessary to compensate because to do so would be double-compensation, or they are externalities, such as claimed environmental or health benefits, which the Commission has clearly stated it cannot take into account to the extent they do not affect utility rates.[68] Therefore, the Companies' proposed Rider NMS-2 compensation rate, perhaps adjusted for system losses, is the most fair, just, and reasonable rate for all customers to pay for intermittent, as-available energy unsupported by legally enforceable obligations.

The Commission's recent order concerning net metering compensation rates for Kentucky Power Company does not alter the Companies' position or evidence in these proceedings.[69]

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[68] *See, e.g.,* Rebuttal Testimony of William Steven Seelye at 53-59.

[69] *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 (PSC Ky. May 14, 2021).

Certain portions of the order, such as those limiting which eligible electric generating facilities may take service under current net metering provisions (i.e., NMS-1 for the Companies) and the recovery of bill credits through an adjustment clause, are consistent with and support the Companies' positions in these proceedings on those same issues.[70]

Other portions of the order are distinguishable from the Companies' positions and evidence. For example, unlike Kentucky Power, the Companies are not PJM members and have not proposed NMS-2 rates that include components other than avoided energy cost.[71] Moreover, unlike the Kentucky Power proceeding, there is affirmative evidence in these proceedings that there is no avoided transmission capacity cost created by net metering and would not be any such savings even if there were net metering capacity equal to 1% of the Companies' system peak.[72] Likewise, there is evidence in these proceedings that the effect of net metering on distribution capacity is minimal at best: KU net metering customers' aggregate capacity is nearly 0.2% of KU's system peak load, yet there is zero net metering capacity connected to 61% of KU's substation transformers, and only 1.4% of KU substation transformers have connected net metering capacity of greater than 1% of substation transformer capacity.[73] Similarly, LG&E net metering customers' aggregate capacity is more than 0.25% of LG&E's system peak load, yet there is zero net metering capacity connected to 43% of LG&E's substation transformers, and only 2.8% of LG&E substation transformers have connected net metering capacity of greater than 1% of substation transformer capacity.[74] There is simply no evidence in these proceedings that such small net metering

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[70] *Id*. at 42, 44-46.
[71] *See, e.g., id.* at 7-8.
[72] Companies' Response to PSC 4 Strategen No. 4.
[73] KU Response to PSC 6-9.
[74] LG&E Response to PSC 6-9.

capacities—even if scaled up to 1% of each of the Companies' peak loads—would have any distribution capacity savings effect.

With regard to nearly all of the other cost categories to which the order in the Kentucky Power proceeding assigned a dollar value—avoided energy cost, avoided generation capacity, avoided environmental compliance, and carbon cost—such avoided costs can be obtained for far less than the values ascribed to them in the order.[75] The evidence in these proceedings regarding the Companies' recent solar PPA shows that these same values can be obtained with performance guarantees backed by liquidated damages and a guaranteed flat price per kWh of just $0.02782 for 20 years, which does not account for revenues from renewable energy certificates ("RECs") the Companies will receive.[76] This is consistent with national solar PPA pricing,[77] as well as the solar PPA prices the Commission recently approved for Big Rivers Electric Corporation.[78] These prices adjusted for likely offsetting REC revenues are essentially the same as the Companies' proposed NMS-2 compensation rates, particularly if the Commission determines to gross up the Companies' proposed rates a full 6% to account for total system losses. Therefore, the Commission's recent order does not undermine the validity of the Companies' proposed Rider NMS-2 compensation rates; rather, when viewed in the context of the evidence in these proceedings, it tends to support the Companies' proposal.

Finally, it is important to reiterate that none of the Companies' current net metering customers will be affected by Rider NMS-2; those customers' facilities will keep their current net metering arrangement under Rider NMS-1 for 25 years. Only future net metering customers will

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[75] *See, e.g.,* Case No. 2020-00174, Order at 39-40 (PSC Ky. May 14, 2021).
[76] *See* Rebuttal Testimony of Robert M. Conroy at 14-16 and Rebuttal Exhibit RMC-1.
[77] *See* Companies' Response to PSC 6-32.
[78] *See Electronic Application of Big Rivers Electric Corporation for Approval of Solar Power Contracts*, Case No. 2020-00183, Big Rivers' Filing in Response to Commission Order on Confidential Treatment Application Exhs. 1-3 (PSC Ky. Apr. 23, 2021).

be affected by Rider NMS-2, meaning that they will get to decide whether they believe that compensation rate—and the full retail rate offset they receive for every kWh they produce and consume onsite—is sufficient to support whatever level of investment they are contemplating. Notably, notwithstanding certain intervenors' assertions, the Rider SQF compensation rate the Companies have proposed for Rider NMS-2 is the same compensation rate the Commission has approved for the Companies' Solar Share Program, which has over 2,700 customers as subscribers and 2 MW of capacity constructed.[79] And the Commission should bear in mind that all customers, not just new net metering customers, will pay through the Companies' Fuel Adjustment Clauses whatever rate the Commission establishes under Rider NMS-2; the one party to these proceedings who is responsible for representing all customers, i.e., the Attorney General, has stated his support for the Companies' proposed Rider NMS-2 compensation rate, not the position advocated by other intervenors.[80] Therefore, the Companies' proposed Rider NMS-2 is fair, just, and reasonable for *all* customers and deserves Commission approval.

B. SQF and LQF

The Companies' SQF and LQF rates and tariff provisions are potentially far more impactful for all customers because there is no statutory cap on the amount of purchase obligation that could result—and the amount could be quite significant when considering that QFs may have electric capacity of up to 80 MW each.[81] When considering possible changes to these rates and tariff provisions, the Commission must remember that whatever compensation rates the Commission establishes, particularly for Rate LQF, could become the new minimum pricing in any future

[79] KU Response to Mountain Association, Kentuckians for the Commonwealth, and Kentucky Solar Energy Society's First Set of Data Requests for Information, No. 58; LG&E Response to Metropolitan Housing Coalition, Kentuckians for the Commonwealth, and Kentucky Solar Energy Society's First Set of Data Requests, No. 61.
[80] *See* Direct Testimony of Stephen J. Baron at 8-12.
[81] *See* 807 KAR 5:054 Section 1(8) and (10).

requests for proposals ("RFP") the Companies issue for new renewable generation; why would a potential supplier provide an RFP response with pricing lower than what the supplier could obligate the Companies to purchase under Rider LQF? Therefore, establishing tariffed QF rates that are above the Companies' avoided costs could harm all customers. All purchased energy from Qualifying Facilities under Rider SQF and Rider LQF are included as purchase power expense in the Companies' Fuel Adjustment Clauses such that those expenses are collected from all retail customers.

Regarding QF capacity payments, the Commission should examine several factors. First, regarding Rider SQF and its associated capacity (100 kW or less per facility), there is no evidence that such small capacity additions would result in any avoided capacity cost. Second, the Commission's QF regulations require a legally enforceable obligation for a QF to receive capacity compensation, but under the terms of the same regulations, as-available energy, which is what solar and wind facilities without energy storage necessarily provide, cannot receive capacity payments.[82] Notably, the markets for solar power purchase agreements recognize this reality and price such agreements only in terms of energy pricing, not capacity pricing.[83] Third, because the Companies currently project that they will not need capacity until 2028 at the earliest, a five-year contract with a QF should have zero capacity value until at least 2023.[84] In addition, as is currently reflected in the Companies' LQF riders, new QFs should receive no capacity payments when the Companies have sufficient capacity. Fifth and finally, a QF's capacity value (indeed, any generating facility's capacity value) should be determined by comparing comparable facilities

[82] *See, e.g.,* 807 KAR 5:054 Section 7(2)(a) and (b).
[83] *See*, *e.g.,* the Companies' Responses to Commission Staff's Sixth Request for Information, No. 32 at 7-9; Attachment to the Companies' Joint Response to Kentucky Solar Industries Association, Inc.'s Post-Hearing Request for Information, No. 10(e)-(g).
[84] *See, e.g.,* 4/27/21 Hearing, VR 13:16:45.

(e.g., comparing solar to solar, not comparing solar to a combustion turbine).[85] It is financially irrational to compensate 10 MW of solar capacity as though it has the same reliability, dispatchability, and performance characteristics—including intermittency—as a more traditional fossil-fueled generating unit. To state the obvious, the Companies could not reliably serve their customers with a generating fleet consisting only of 8,000 MW of solar and wind resources; compensation to QFs should reflect this crucial operating reality and compensate for capacity only by comparison to comparable resources.

Here a comparison to the 100 MW solar PPA into which the Companies recently entered is apt. Under the term of that PPA, the Companies will receive the full output of a 100 MW solar facility for a 20-year term with no capacity payments and a flat, unchanging energy purchase rate of $27.82/MWh for the entire 20-year term.[86] The PPA also contains availability guarantees backed by liquidated damages.[87] This arrangement is likely stronger than most legally enforceable obligations with large QFs in terms of guarantees and financial commitments to the utility being served, yet there are no capacity payments at all. The Companies believe this approach, *i.e.*, no capacity payments for solar facilities, is not exceptional; rather, it is the rule in the marketplace. Therefore, if the Commission decides to alter the Companies' QF tariffs in these proceedings, it must take into account the nature of the QF being offered in establishing capacity rates and obligations. Again, to set QF compensation above the Companies' truly avoided costs—and certainly above market rates—could result in large amounts of QF capacity interconnecting with the Companies' system with a significant purchase obligation.[88]

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[85] *See, e.g.,* 4/27/21 Hearing, VR 13:18:30 – 13:20:40.
[86] *See* Rebuttal Testimony of Robert M. Conroy at 14-16 and Rebuttal Exhibit RMC-1.
[87] *See id.*
[88] *See* 807 KAR 5:054 Section 1(8) and (10).

Finally, Kentucky's current QF regulations state that a utility may refuse to purchase from a QF when the cost of such purchases would exceed the utility's own costs to generate power.[89] Establishing a QF purchase rate that exceeds the Companies' own generating costs would therefore be unhelpful to QFs because the Companies would have to refuse to purchase from them in order to provide all customers with safe and reliable service at the lowest reasonable cost.

III. Hearing Room Issues

A. CSR

The Companies' Curtailable Service Riders (Riders CSR-1 and CSR-2) remain valuable physical capacity resources during emergency conditions and provide additional economic value through buy-through curtailments.[90] For example, during the 2014 Polar Vortex when system resources were strained, the Companies were able to call CSR physical curtailments to meet the additional heating load needed to protect human life and property.[91] Also, as shown in the Companies' discovery responses, the Companies called buy-through curtailment events numerous times in recent years when it was financially advantageous to other customers to do so.[92] Therefore, the Companies' Curtailable Service Riders continue to provide value to all customers in several ways; and the Commission should approve the retention of them in their current form as part of the overall Stipulation agreed to by all parties to these proceedings.

B. Late Payment Charges

Several of the Companies' existing tariffs for residential customers, namely Rates RS, RTOD-E, and RTOD-D, allow customers to request a one-time waiver of late payment charges if they have a recent history of paying on time: "Beginning May 1, 2019, Residential Service

[89] 807 KAR 5:054 Section 6(2).
[90] *See* 4/27/21 Hearing, VR 17:10:10.
[91] *See* 4/27/21 Hearing, VR 17:11:33.
[92] *See* Companies' Responses to AG-KIUC 1-138. *See also* 4/27/21 Hearing, VR 17:12:00.

Customers in good standing by not having been assessed a Late Payment Charge for the previous eleven (11) months have the option of waiving one (1) late payment charge upon request. This option may only be used once every twelve (12) months as long as the Customer remains in good standing."[93]

The Commission inquired at the hearing whether the Companies make residential customers aware of the availability of this late payment charge waiver, other than including the provision in the Companies' tariffs.[94] The Companies have considered the Commission's concern since the hearing and are proactively responding. Specifically, both LG&E and KU are including language about the availability of the late payment charge waiver in the June 2021 edition of the *PowerSource* newsletter, which will be distributed to customers starting on June 2, 2021. This newsletter is an insert to all residential customer paper bills and is distributed by e-mail to customers who receive communications via electronic means. The Companies have also posted new language about the availability of the late payment charge waiver on their website.[95]

Any change to the LPC waiver mechanism to automatic instead of by request would impact the revenue requirement as reflected in the parties' negotiated stipulation.

C. Companies' Remaining Separate Legal Entities

The Commission inquired at the hearing as to the benefits that could be achieved by a full legal merger of KU and LG&E. Since their merger in 1998, KU and LG&E have been able to extend their efficient performance by taking advantage of synergies, combined work practices, lower overhead and administrative staff expenses, and other economies of scale. All of those efforts have allowed the Companies to continue providing safe and reliable service with significant

[93] Kentucky Utilities Rate RS, P.S.C. No. 19, Second Revision of Original Sheet No. 5, available at: https://psc.ky.gov/tariffs/Electric/Kentucky%20Utilities%20Company/Tariff.pdf.
[94] 4/26/21 Hearing, VR 15:46:00.
[95] https://lge-ku.com/assistance-programs (Ways to manage your bill).

savings to customers. As directed by the Commission, KU and LG&E have thoroughly analyzed whether there are additional benefits of a legal merger of the two utilities.[96] This analysis indicates that while the legal merger of KU and LG&E would result in savings in the accounting, tax, and regulatory areas of approximately $2 million annually, it would also result in an increase of ongoing costs in other areas and significant one-time costs of approximately $23 million. Importantly, such a legal merger also creates winners and losers among customers because the analysis shows there would not be sufficient net savings to bring all customer rates to the lowest rate offered between the Companies. For these reasons, the Companies do not recommend a legal merger of KU and LG&E but will continue to evaluate this possibility and other means to operate more efficiently.

D. Electric Vehicle Charging

The Companies' witnesses responded to a number of questions from the Commission at the hearing regarding the proposed EVC-FAST tariff and their plan to install Level 3 electric vehicle charging stations in Kentucky. As Ms. Saunders stated in her direct testimony, the Companies have budgeted approximately $306,000 each for installation of four total EV changing stations – two in LG&E's service territory and two in KU's service territory.[97] This proposed investment is planned for 2022 and is therefore outside the forecast test year.[98] The Companies are also part of a cohort of utilities, including Duke Energy, Big Rivers, East Kentucky Power, TVA, and Kentucky Power, who seek to leverage funds from the Volkswagen emissions settlement

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[96] Case Nos. 2018-00294 and 2018-00295, Order at 34, Ordering Paragraph No. 7 (Ky. PSC Apr. 30, 2019). The Companies have filed legal merger studies in the post-case files of the 2018 rate cases on March 31, 2020, and March 31, 2021. *See also Electronic Joint Application of PPL Corporation, PPL Subsidiary Holdings, LLC, PPL Energy Holdings, LLC, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of an Indirect Change of Control of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2017-00415, LG&E and KU Internal Study of Potential Legal Merger (Ky. PSC Aug. 8, 2018).
[97] Testimony of Eileen L. Saunders at 41.
[98] *Id.*

trust and get dollar for dollar matching funds to invest in Level 3 EV charging infrastructure.[99] If those funds are received, the Companies will be able to install eight total Level 3 charging stations – four in each company's service territory, for the same level of investment.[100]

The purpose of this proposed investment and the EVC-FAST tariff is not to profit from EV station users or compete with third-party providers – but rather to provide foundational infrastructure to support the growth and increased adoption of electric vehicles by Kentuckians and those visiting the Commonwealth. Mr. Seelye described the importance of this infrastructure in detail in his direct testimony, including the concept that the "infrastructure gap" between the demand for EVs and the ability to support their use with fast charging "demands all hands on deck, including participation of utilities."[101]

The Companies understand from the Commission's questions posed to Mr. Bellar at the hearing that the Commission wishes to ensure that the Companies will not operate their Level 3 charging stations in a manner that discourages competition – either in locating EV stations or in the rates charged to stations users. The record in these proceedings provides that assurance. In his direct testimony, Mr. Seelye states "[i]t is important to recognize that KU and LG&E are not trying to compete with third-party providers of DC Fast Charging service, and the Companies are not trying to undercut other providers by providing a below market price for fast charging service."[102] Mr. Bellar likewise confirmed during hearing testimony that the Companies intend to fill infrastructure gaps that have not been met – not to dominate the market for EV fast charging in their service territories.[103] The Companies' proposed rates for their Level 3 charging stations

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[99] *Id.* at 40.
[100] KU Response to Commission Staff's Third Request for Information, No. 6.
[101] Direct Testimony of William Steven Seelye at 71, quoting NARUC publication *Electric Vehicles: Key Trends, Issues, and Considerations for State Regulators*.
[102] Direct Testimony of William Steven Seelye at 74-75.
[103] 4/28/21 Hearing, VR 13:44:20.

are market based, not cost based.[104] The rates are intended to be competitive with, but not significantly below, the rates charged by third-party providers of similar charging services.[105] Finally, the Companies will conduct the same analysis when locating their own EV charging stations as they currently use and will continue to use for locating their customers' EV charging stations.[106] In both cases, the objective is to locate stations where they are desirable and convenient for users, while minimizing system upgrade costs associated with increased load.

E. Rate Outdoor Sports Facility Lighting

At the hearing, the Commission inquired about the number of customers taking service under the Companies' Outdoor Sports Lighting rate (Rate OSL) and the Companies' efforts to make customers aware of the rate.[107] As the Companies noted in discovery, they have proactively discussed this rate option with local schools and parks.[108] Indeed, as a result of customer feedback, the Companies proposed in these proceedings a tariff change to reduce the summer peak between May through September by one hour, allowing ball fields to start their games earlier.[109] The Companies will continue to dialog with their customers to help identify possible improvements to Rate OSL that could be implemented in the Companies' next rate cases and may increase the number of customers served under Rate OSL in the meantime.

F. Economic Development Commitments

At the hearing, Vice Chairman Chandler and Commissioner Mathews inquired as to the Companies' plans for the annual payments from Big Rivers that will begin in 2023. As Mr. Blake

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[104] Direct Testimony of William Steven Seelye at 71-75.
[105] Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, No. 31.
[106] Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, No. 32; *see also* 4/28/21 Hearing, VR 12:08:45.
[107] *See* 4/28/21 Hearing, VR 12:04:15-12:07:15.
[108] KU Response to Commission Staff's Second Request for Information, No. 106; LG&E Response to Commission Staff's Second Request for Information, No. 120.
[109] *See* Companies' Response to PSC Post-Hearing DR 34.

testified at the hearing, the Companies commit to use these funds for incremental economic development in the LG&E service territory. The Companies intend to be completely transparent with the use of these funds and will provide annual reporting on any payments received and funds expended toward economic development.

G. Bullitt County Pipeline Status

The reliability need for the Bullitt County pipeline has not changed and the capacity need for this pipeline has only continued to grow since the CPCN was issued in 2017.[110] Some 9,500 existing customers currently are served from a radial line in Mt. Washington. An outage along that line could result in thousands of customers' natural gas service being interrupted.[111] The need for the Bullitt County pipeline to maintain reliability for gas service in this area has not changed. With regard to capacity, there is no current availability for new natural gas hookups in the area.[112] At present, 450 homes and businesses have been denied requests for new or expanded natural gas service.[113] These denials include residential developments, a parish, restaurants, hotels, and schools. The capacity need for this pipeline has only increased since the CPCN was issued.

Upon obtaining the CPCN, LG&E has taken all reasonable steps to proceed with constructing the line. It has acquired approximately 90% of the right-of-way necessary to construct the pipeline.[114] A small minority of outstanding rights-of-way are involved in condemnation actions.[115] On May 18, 2021, the Bullitt Circuit Court entered an order finding LG&E has the

[110] Case No. 2016-00371, Order at 34 (June 22, 2017)
[111] Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, No. 9.
[112] *Id.*
[113] *Id.*
[114] *Id.*
[115] *Id.*

right to condemn seven properties and directing the property owners of those seven parcels to make conveyance to LG&E the rights and easements sought should exceptions not be taken.[116]

Other actions LG&E has taken in furtherance of the pipeline include twice obtaining bids for construction of the line. Based upon the estimates received from the bids, as well as the delayed construction of the line due in part to the contested condemnation proceedings by a handful of property owners, LG&E has revised its cost estimate for the project to approximately $74 million.[117] LG&E will seek bids again when the construction date is more certain, but LG&E disagrees that its cost estimates are outdated.[118] In calculating its estimate, LG&E has continuously evaluated whether the pipeline remains the lowest cost alternative to remedy the reliability and capacity concerns in Bullitt County. Results from the most recent analysis are shown in the following table. The pipeline estimate in this analysis and the current estimate are based on construction bids received from a second bid solicitation. As shown below, the pipeline option remains the least cost option when compared to the cost for alternate routes or options.[119]

Alternative	PVRR ($M Dollars)	Levelized RR/ccf [120] ($)	Levelized RR/ccf less Incremental Revenues[121] ($)
Pipeline	79.2	0.509	0.359
Looping	107.8	0.796	0.651
Intermediate Looping	43.0	2.315	1.753
LNG	320.3	1.921	1.770

Thus, further review of the CPCN for the Bullitt County natural gas pipeline project is not necessary or otherwise supported by the record.[122]

[116] This order addressed all but one of the remaining properties in condemnation. The condemnation of the Bernheim property is still ongoing.
[117] *Id.*
[118] *Id.*
[119] Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, No. 10.
[120] Levelized revenue requirements per incremental ccf of gas served.
[121] Incremental revenues are estimated based on current rates.
[122] Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, No. 9.

When issuing a CPCN, the Commission does not simultaneously find that the utility is guaranteed recovery of the costs in rates. Instead the issuance of a CPCN is based on the findings that the applicant has established a need for such facilities and an absence of wasteful duplication, meaning a thorough review of all reasonable alternatives has been performed. The record regarding these points for the Bullitt County pipeline remain undisputed; the pipeline is sorely needed and there is no lower cost reasonable alternative. The Commission can review the costs incurred to construct the pipeline in future rates cases to assess whether they were reasonably incurred.

H. TVA/PJM Joint Reliability Coordination Agreement

The Commission correctly noted at the hearing that the Companies have been in negotiations to be added as a party to the Joint Reliability Coordination Agreement ("JRCA") between PJM Interconnection, L.L.C. and Tennessee Valley Authority ("TVA").[123] Those negotiations remain ongoing and the Companies do not have a definite timeframe by which an agreement will be reached. In many respects, adding LG&E and KU to the JRCA will formalize coordination of transmission planning and congestion management practices that already occur informally. However, as Mr. Bellar testified in the hearing, by being added as parties to the JRCA the Companies expect to achieve improved information sharing and coordination between PJM, TVA, and the Companies related to certain activities that have the potential to affect the Companies' transmission system and neighboring systems.[124] One consideration in particular is joint coordination and planning for generation interconnection requests, either on the Companies' system or neighboring systems served by PJM, that may impact regional transmission planning

[123] 4/26/21 Hearing, VR 10:50:30.
[124] 4/26/21 Hearing, VR 10:51:50.

and performance.[125] An executed amendment to the JRCA would be filed with FERC although the primary filing party has not been determined.[126] Minimally the Companies would be required to make a FERC filing to incorporate the JRCA into their electronic tariff records.[127]

I. MEGA Rule Part 1 Compliance / In-line Inspections

LG&E has budgeted an increase of $10.766 million in expenses related to inline inspections of gas transmission lines between the base year and the forecast test year. Commission Staff and Vice Chairman Chandler asked a number of questions of Mr. Bellar at the hearing regarding the use of inline inspection ("ILI") tools, alternatives to ILI for achieving regulatory compliance, and the extent to which ILI is used on transmission lines outside of high-consequence areas.[128] LG&E has provided detailed responses on these topics in response to the Commission's post-hearing data requests, particularly in its response to the Commission's Post-Hearing Data Request No. 2 and the attachment provided in response to Post-Hearing Data Request No. 4. In summary, LG&E has determined that use of ILI where it is currently deployed is the most robust, comprehensive, and cost-effective means of complying with requirements imposed by MEGA Rule Part 1 and ensuring a high level of overall pipeline safety. That determination is consistent with the Commission's previous orders on the subject – specifically – the Commission's conclusion that "use of ILI tools to conduct integrity reassessment is preferable to assessment by other accepted methods."[129]

Regulatory requirements necessitating the use of ILI include verification and documentation of pipeline material properties and attributes (49 C.F.R. § 192.607) and

[125] 4/26/21 Hearing, VR 10:51:05.
[126] Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, No. 3.
[127] *Id.*
[128] 4/26/21 Hearing, VR 10:31:00, 11:21:30.
[129] *Application of Louisville Gas and Electric Company for Approval of State Waiver of the Reassessment Interval Required by 49 C.F.R. 192.939*, Case No. 2017-00482, Order at 14 (Ky. PSC June 3, 2019).

performance of engineering critical assessments (49 C.F.R. § 192.632) which are then used as a method of compliance for periodic reconfirmation of maximum allowable operating pressure ("MAOP") (49 C.F.R. § 192.624). Other allowable means of reconfirming MAOP for designated pipelines include pressure testing, pressure reduction, and replacement of the pipeline, none of which are practicable or cost-effective for LG&E's system or gas customers.[130] LG&E uses ILI on portions of pipeline that are not contained in HCAs.[131] However, as Mr. Bellar testified at the hearing, most inline inspections performed outside of HCAs are done on pipelines that contain segments within HCAs or moderate-consequence areas which require use of ILI for regulatory compliance.[132] On those pipelines, ILI can be performed on non-HCA segments at relatively low incremental cost and provide overall benefits for the safety and integrity of the system above what can be achieved through traditional means of inspection.[133] Indeed, using ILI for the entire pipeline where possible is much more cost-effective than using ILI only within HCAs because of the cost associated with installing in-line inspection launchers and receivers at each section of pipeline to be inspected.[134]

ILI is currently used on only two pipelines that do not contain HCAs and are not otherwise subject to MAOP reconfirmation under 49 C.F.R. 192.624 – the Doe Valley 8" pipeline and the Ballardsville distribution pipeline.[135] Population density along these lines along with their system characteristics inform LG&E's decision to inspect this pipeline using ILI tools.[136] While 49 C.F.R. Part 192 dictates minimum pipeline standards, LG&E must still exercise judgment about the value of using enhanced tools or greater than minimum inspections to achieve overall pipeline safety

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[130] Attachment to Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, No. 4.
[131] Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, No. 2.
[132] 4/26/21 Hearing, VR 11:33:00.
[133] *Id.*
[134] Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, No. 6.
[135] Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, Nos. 2, 5.
[136] Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, No. 6.

and to implement industry best practices. It is important to note that even before PHMSA promulgated Mega Rule Part 1, use of ILI was considered to be industry best practice for performing integrity assessments.[137] Sound, reasonable, and safety-focused utility practice favors use of ILI on the Doe Valley and Ballardsville pipelines.

With the promulgation of Mega Rule Part 1, ILI not only provides the most effective means to perform pipeline integrity assessments but also the most effective means to comply with 49 C.F.R. §§ 192.710, 192.624, and 192.607. No other inspection alternative provides that level of overall benefit to support regulatory compliance.[138] Accordingly, use of ILI on LG&E's system as proposed in the test year is both reasonable and cost-effective and allows LG&E to achieve higher overall pipeline safety.

J. Probable Retirement of Mill Creek Units 1 and 2

As reflected in Mr. Bellar's hearing testimony and in the analysis attached as Exhibit LEB-2 to his direct testimony, the probable retirement date for Mill Creek Unit 1 is the end of 2024. Due to pressures imposed by environmental compliance – namely sizing of Effluent Limitations Guidelines ("ELG") treatment capacity for the Mill Creek station and the inability to run Mill Creek 1 and 2 simultaneously during ozone season in the absence of SCR technology, the probable retirement of Mill Creek 1 was driven by economics and was the least cost alternative. In response to post-hearing data requests in the Companies' Environmental Cost Recovery cases for construction of ELG treatment facilities at Ghent, Trimble County, and Mill Creek generating stations, the Companies stated:

> As discussed below and shown in the Applications, the Companies' recommended 2020 ECR compliance plan does not include installing enough water processing capability at Mill Creek to

[137] Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, No. 2.
[138] *Id.*

> continue to operate Mill Creek Unit 1 ("MC1") because it is uneconomic to continue its operation beyond December 31, 2024.[139]

This response was filed with the Commission on September 18, 2020. As Mr. Bellar testified in these proceedings, at the same time the Companies were providing these responses, "around the September 20, 2020 timeframe," they were preparing their base rate cases, which are supported by an updated depreciation study prepared by Mr. Spanos.[140] At that time, the Companies had to provide to Mr. Spanos an assessment of the most reasonable retirement dates for all of their generating units to support revised depreciation rates. For Mill Creek 1, the Companies provided to Mr. Spanos for purposes of the depreciation study a probable retirement date of 2024, the same date assumed throughout the ECR case for ELG compliance, and the same date contained in the post-hearing data requests contemporaneously filed with the Commission. This represented at that point and time "the most reasonable retirement date for Mill Creek 1."[141] The conditions supporting the Companies' decision to use 2024 as the retirement date for Mill Creek 1 in the ECR case and in Exhibit LEB-2 to Mr. Bellar's testimony in these proceedings still exist today, and thus that remains the most reasonable and economic retirement date for Mill Creek 1.[142]

With respect to Mill Creek 2, the Commission inquired at the hearing about the inputs to stay open costs contained in Tables 6 and 8 of Exhibit LEB-2. The Companies' response to the Commission's post-hearing data requests speak to the timing of those inputs.[143] The Companies further note that at the time the ECR case for the ELG water treatment system for Mill Creek was

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[139] *Electronic Application of Louisville Gas and Electric Company for Approval of its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00061, LG&E Response to Commission Staff's Post-Hearing Request for Information, No. 2 (filed Sept. 18, 2020).
[140] 4/28/21 Hearing, VR 11:43:00.
[141] 4/28/21 Hearing, VR 11:43:26.
[142] 4/28/21 Hearing, VR 11:44:00.
[143] Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, No. 38.

filed, the incremental cost to build ELG treatment capacity for Mill Creek 2 was $9 million, out of total station cost of $113.9 million.[144] This was the difference between sizing the ELG water treatment system to accommodate 450 gallons per minute (Mill Creek 3 and 4 only) or 600 gallons per minute (3 total units). Since that time, and as reported in the Companies' most recent quarterly filing for the 2020 ECR cases, the cost estimates to construct ELG treatment capacity and diffuser for the Mill Creek generating station have gone down significantly, from $113.9 million in the ECR filing to $66.9 today.[145] The incremental cost to construct ELG capacity to accommodate Mill Creek 2 is now less than $6 million. That capital will be incurred before the end of 2025 and is not reflected in the stay open costs outlined in Tables 6 and 8 of Exhibit LEB-2. The only ELG-related expenses attributed to Mill Creek 2's stay open costs are the costs of consumables (chemicals) needed to treat its capacity in 2026 to 2028.[146] Those costs amount to a very small percentage (2 to 3 percent, or less than $1 million annually) of the stay open costs attributed to the unit in 2026, 2027, and 2028.[147]

As reported in Exhibit LEB-2 and by Mr. Bellar at the hearing, proposed retirement of Mill Creek 1 and Mill Creek 2 in 2024 and 2028, respectively, continues to be the most reasonable and least-cost alternative given expected impact of National Ambient Air Quality Standards and ELG compliance costs.

K. SEEM

At the hearing Mr. Bellar testified that the FERC filing for the Southeast Energy Exchange Market ("SEEM") was pending and a decision was expected in May.[148] After the conclusion of

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[144] Case No. 2020-00061, Direct Testimony of Stuart A. Wilson, Exhibit SAW-1 at 8 to (filed Mar. 31, 2020).
[145] Case No. 2020-00061, April 30, 2021 Quarterly Report – Update #2 (Post Case Files).
[146] Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, No. 38.
[147] *Id.*
[148] 4/28/21 Hearing, VR 14:28:35.

the hearing, on May 4, 2021, FERC issued a deficiency letter to the filing parties seeking additional information about the functioning of the market, pricing, controls to protect against market manipulation, requirements for participation in the market, and a number of other matters. The Companies will work with the other SEEM participants to address FERC's deficiency letter and file an amended application with FERC. The budgeted startup and initial administrative costs for SEEM in the test year are minimal, totaling $23,000 for both Companies.[149] Notwithstanding the delays associated with FERC approval and the deficiency letter, the Companies continue to expect SEEM to be a good value proposition for their customers, providing both an efficient means to generate off-system sales revenue for the benefit of ratepayers and a source for low cost energy in the marketplace.[150]

L. Study of Customer Income vs. Consumption

At the hearing, the Commission also inquired about the study the Companies had performed concerning correlations between customers' energy usage and income levels.[151] In an exchange with Vice Chairman Chandler, Mr. Bellar agreed that there were valid reasons to study the connections between usage and income, and indicated that the Companies would continue to study the issue.[152] The Companies will do so.

M. Office Space and Future Planning

Like most other businesses in the Commonwealth and around the country, LG&E and KU are in the midst of evaluating and planning for a "return to office/remote work" future post COVID-19, as health risks decline, and recommended safety protocols become less stringent. As demonstrated by less restrictive CDC guidance issued in the past few weeks, this process must

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[149] Companies' Joint Response to Commission Staff's Post-Hearing Request for Information, No. 1.
[150] Testimony of Lonnie E. Bellar at 19.
[151] *See* 4/28/21 Hearing, VR 12:01:30 – 12:04:15. *See also* the Companies' Responses to Commission Staff's Third Request for Information, No. 28.
[152] *See* 4/28/21 Hearing, VR 12:03:25.

adapt and respond to constantly evolving information. Even before the pandemic, the Companies utilized a detailed space planning process, tied in with their workforce planning process, to ensure that adequate facilities are available to meet the Companies' operational needs.[153] Going forward, that process will account for and be informed by the Companies' return to office strategy, [154] taking into consideration circumstances where remote work or hybrid office work/remote work provides overall higher value to employees, the Companies, and customers. Notwithstanding the possibility of adaptive approaches to physical facilities to meet the needs of their workforce, LG&E and KU continue to maintain their principal offices in downtown Louisville and downtown Lexington, respectively, as they committed to do for the 15 years following the closing date of their acquisition by PPL.[155]

N. Resumption of Residential Customer Disconnects

Ms. Saunders testified at the hearing that the Companies planned to resume residential disconnects for non-payment around June 15, 2021.[156] That remains the expected date for resumption of this activity. The Commission's Order entered on September 21, 2020 in Case No. 2020-00085 rescinded the moratorium on residential disconnects for nonpayment effective October 20, 2020, subject to certain conditions, including creation of payment plans for customers in arrears.[157] The Companies complied with those conditions and extended payment plans to customers behind on their payments. Although the Companies now have customers eligible for nonpayment disconnection and have been permitted to complete those disconnections for some

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[153] 4/26/21 Hearing, VR 12:03:39.
[154] 4/26/21 Hearing, VR 12:03:53.
[155] *Joint Application of PPL Corporation, E. ON AG, E. ON US Investments Corp., E. ON U.S. LLC, Louisville Gas and Electric Company, and Kentucky Utilities Company for Approval of an Acquisition of Ownership and Control of Utilities*, Case No. 2010-00204, Order at 17 (Ky. PSC Sept. 30, 2010).
[156] 4/26/21 Hearing, VR 15:43:00.
[157] *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19*, Case No. 2020-00085, Order at 6 (Ky. PSC Sept. 21, 2020).

time, they have refrained from resuming disconnections to date. Primarily, the Companies have delayed resumption of disconnections to allow their customers to take advantage of available financial assistance programs to help them get current on their bills. These include state-funded COVID-relief programs and programs like the Louisville Metro COVID-19 Utility Assistance Program, which offered up to $1,000 in utility assistance to eligible customers and is set to expire on June 30, 2021.[158]

The Companies are currently executing on a comprehensive communications plan regarding the resumption of residential disconnects for nonpayment. This includes notification and outreach to key stakeholders including the Commission, city and state governments, the press, local low-income assistance agencies and, of course, customers. In April the Companies posted information about the June resumption of residential disconnects on their website,[159] social media accounts, and are notifying customers in arrears in writing throughout the May billing cycle. Many of these communications include detailed information on payment-assistance resources to help customers get current on their balances and avoid disconnections when they resume.

O. Recovery of Incentive Compensation Under the Team Incentive Award Plan Should be Approved and is Consistent with Recent KPSC Precedent

At the hearing, Mr. Meiman received questions regarding the availability and calculation of incentive compensation under the Companies' Team Incentive Award Plan ("TIA Plan"). Specifically, he received questions about the factors used in calculating the amount an individual employee may earn. He responded and also noted that the TIA Plan is described in his direct

[158] *Metro Government Announces Expanded Benefits, Streamlined Intake Process for LG&E Utility Assistance Program*, Louisvilleky.gov (Mar. 25, 2021), available at: https://louisvilleky.gov/news/metro-government-announces-expanded-benefits-streamlined-intake-process-lge-utility-assistance (last visited May 18, 2021).
[159] *Important COVID-19 Information for LG&E Customers*, available at: https://lge-ku.com/covid-19/community-lge (last visited May 18, 2021).

testimony and a copy of the TIA Plan brochure is attached to his direct testimony as Exhibit GJM-1.[160]

The TIA Plan brochure explains the factors used in determining the amount of incentive compensation an employee may earn. They are: customer satisfaction; customer reliability; cost control; corporate safety; and individual and team effectiveness measures.[161] Mr. Meiman has explained what those factors are, their weightings, and how they are applied in calculating an award.[162] The TIA Plan brochure itself shows a sample calculation.

Notably absent from the TIA Plan is any sort of financial predicate or "trigger" that the Companies must meet for incentive compensation to be payable to employees. In response to Staff discovery, the Companies have confirmed that TIA Plan incentive compensation is in no way tied to or predicated upon the Companies' financial performance.[163] It is paid without regard to the Companies' financial performance. Thus, under Commission precedent on this issue, it is fully recoverable in rates.[164] Finally, even with the inclusion of incentive compensation, the Companies have demonstrated that compensation levels are consistent with market levels when compared to the utility industry and general industry.[165] Thus, incentive compensation should be fully recovered in rates.

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[160] 4/27/21 Hearing, VR 9:40:00.
[161] Testimony of Gregory J. Meiman at 12-13; *see also* Exhibit GJM-1.
[162] *Id.*
[163] KU Response to Commission Staff's Second Request for Information, No. 56; LG&E Response to Commission Staff's Second Request for Information, No. 62.
[164] The Commission has addressed the recoverability of incentive compensation numerous times. Most recently, the Commission clarified its precedent in *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 Convenience and Necessity; and (5) All Other Required Approvals and Relief*, Case No. 2020-00174, Order at 12-15 (Ky. PSC Jan. 13, 2021). Under that decision and the precedent it clarified, the absence of a financial funding measure and the absence of a financial performance measure mean that full rate recovery should be allowed.
[165] Testimony of Gregory J. Meiman at 9-10; Applications, Tab 60, Attachment 3 at 5.

CONCLUSION

For the reasons stated in this brief and the record, Kentucky Utilities Company and Louisville Gas and Electric Company request the Commission issue an order by June 30, 2021 granting the Companies the following relief:

A. The Commission should accept the Stipulation as the reasonable disposition of the revenue requirements, revenue allocations, rate design and AMI issues.

B. The Commission should approve the proposed changes in rates, terms and conditions set forth in Stipulations for service rendered by KU and LG&E on and after July 1, 2021.

C. The Commission should approve the depreciation rates set forth in the Stipulation Exhibit 1 as reasonable for KU and LG&E.

D. The Commission should grant KU and LG&E the certificates of public convenience and necessity for the full deployment and implementation of Advanced Metering Infrastructure in KU's and LG&E's Kentucky service territories.

Dated: May 24, 2021

Respectfully submitted,

Kendrick R. Riggs
Stoll Keenon Ogden PLLC
500 West Jefferson Street, Suite 2000
Louisville, Kentucky 40202-2828
Telephone: (502) 333-6000
Fax: (502) 627-8722
kendrick.riggs@skofirm.com

Allyson K. Sturgeon
Managing Senior Counsel
Regulatory and Transactions
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2088
Fax: (502) 627-3367
allyson.sturgeon@lge-ku.com

Counsel for Kentucky Utilities Company and Louisville Gas and Electric Company

CERTIFICATE OF COMPLIANCE

In accordance with 807 KAR 5:001 Section 8(7), this is to certify that Kentucky Utilities Company and Louisville Gas and Electric Company's May 24, 2021 electronic filing is a true and accurate copy of the Joint Post Hearing Brief of Louisville Gas and Electric Company and Kentucky Utilities Company being filed in paper medium; that the electronic filing has been transmitted to the Commission on May 24, 2021; that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and that a true and correct copy in paper medium will be delivered to the Commission within 30 days of the lifting of the State of Emergency.

Counsel for Kentucky Utilities Company
and Louisville Gas and Electric Company