Jennifer Brooks Hutchinson
Senior Counsel
PPL Services Corporation
JHutchinson@pplweb.com

280 Melrose Street
Providence, RI 02907
Phone 401-784-7288

Rhode Island Energy™
a PPL company

April 27, 2023

VIA ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 22-49-EL-The Narragansett Electric Company d/b/a Rhode Island Energy Advanced Metering Functionality Business Case
Responses to Commission Data Requests – PUC Set 4

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company"), attached is the electronic version of Rhode Island Energy's supplemental response to PUC 4-4 from the Public Utilities Commission's Fourth Set of Data Requests in the above-referenced matter.[1]

Thank you for your time and attention to this matter. If you have any questions, please contact Jennifer Brooks Hutchinson at 401-316-7429.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

cc: Docket No. 22-49-EL Service List
John Bell, Division
Leo Wold, Esq.

[1] Per communication from Commission counsel on October 4, 2021, the Company is submitting an electronic version of this filing followed by hard copies filed with the Clerk within 24 hours of the electronic filing.

CERTIFICATE OF SERVICE

I certify that a copy of the within documents was forwarded by e-mail to the Service List in the above docket on the 27th day of April, 2023.

Adam M. Ramos, Esq.

The Narragansett Electric Company d/b/a Rhode Island Energy
Docket No. 22-49-EL Advanced Meter Functionality (AMF)
Service list updated 4/6/2023

Name/Address	E-mail Distribution List	Phone
The Narragansett Electric Company d/b/a Rhode Island Energy Jennifer Hutchinson, Esq. 280 Melrose Street Providence, RI 02907	JHutchinson@pplweb.com; JScanlon@pplweb.com; COBrien@pplweb.com; CAGill@RIEnergy.com; JOliveira@pplweb.com; BLJohnson@pplweb.com; SBriggs@pplweb.com; KGrant@RIEnergy.com; wanda.reder@gridxpartners.com; PJWalnock@pplweb.com;	401-784-7288
Hinckley Allen Adam Ramos, Esq. 100 Westminster Street, Suite 1500 Providence, RI 02903-2319	aramos@hinckleyallen.com; cdieter@hinckleyallen.com; cwhaley@hinckleyallen.com; ssuh@hinckleyallen.com;	401-457-5164
Division of Public Utilities (Division) Leo Wold, Esq. Christy Hetherington, Esq. Division of Public Utilities and Carriers 89 Jefferson Blvd. Warwick, RI 02888	Leo.Wold@dpuc.ri.gov; Christy.Hetherington@dpuc.ri.gov; Margaret.L.Hogan@dpuc.ri.gov; John.bell@dpuc.ri.gov; Al.contente@dpuc.ri.gov; Joel.munoz@dpuc.ri.gov; Linda.George@dpuc.ri.gov; Ellen.golde@dpuc.ri.gov; Machaela.Seaton@dpuc.ri.gov;	401-780-2177

	Al.mancini@dpuc.ri.gov; Paul.Roberti@dpuc.ri.gov; Thomas.kogut@dpuc.ri.gov; John.spirito@dpuc.ri.gov;	
Mike Brennan	mikebrennan099@gmail.com;	
Robin Blanton	robin.blanton@ieee.org;	
William Watson	wfwatson924@gmail.com;	
David Littell	dlittell@bernsteinshur.com;	
Gregory L. Booth, PLLC 14460 Falls of Neuse Rd. Suite 149-110 Raleigh, NC 27614 Linda Kushner L. Kushner Consulting, LLC 514 Daniels St. #254 Raleigh, NC 27605	gboothpe@gmail.com; lkushner33@gmail.com;	
Office of Attorney General Nick Vaz, Esq. 150 South Main St. Providence, RI 02903	nvaz@riag.ri.gov; mbedell@riag.ri.gov;	401-274-4400 x 2297
Office of Energy Resources (OER) Albert Vitali, Esq. Dept. of Administration Division of Legal Services One Capitol Hill, 4th Floor Providence, RI 02908 Chris Kearns, OER	Albert.Vitali@doa.ri.gov; nancy.russolino@doa.ri.gov; Christopher.Kearns@energy.ri.gov; Shauna.Beland@energy.ri.gov; Matthew.Moretta.CTR@energy.ri.gov; Anika.Kreckel@energy.ri.gov; Steven.Chybowski@energy.ri.gov; Nathan.Cleveland@energy.ri.gov; William.Owen@energy.ri.gov;	401-222-8880
Acadia Center Hank Webster, Esq. Acadia Center 31 Milk St., Suite 501 Boston MA 02109-5128	HWebster@acadiacenter.org;	401-276-0600 x 402

Mission:data Coalition James G. Rhodes, Esq. Rhode Consulting LL 160 Woonsocket Hill Rd. North Smithfield, RI 20896	james@jrhodeslegal.com;	401-225-3441
George Wiley Center Jennifer L. Wood, Executive Director R.I. Center for Justice 1 Empire Plaza, Suite 410 Providence, RI 02903	jwood@centerforjustice.org; georgewileycenterri@gmail.com; camiloviveiros@gmail.com;	
NRG Retail Companies Craig Waksler, Esq. Eckert Seamans Cherin & Mellott, LLC Two International Place, 16th Floor Boston, MA 02110	CWaksler@eckertseamans.com; Kmoury@eckertseamans.com; sstoner@eckertseamans.com;	617-342-6890 717-237-6000
Conservation Law Foundation (CLF) James Crowley, Esq. Conservation Law Foundation 235 Promenade Street Suite 560, Mailbox 28 Providence, RI 02908	jcrowley@clf.org; mcurran@clf.org;	401-228-1905
Original & 9 copies file w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov; Emma.Rodvien@puc.ri.gov; Christopher.Caramello@puc.ri.gov;	401-780-2107
Interested Parties:		
Victoria Scott (GOV)	Victoria.Scott@governor.ri.gov;	
Seth Handy, Esq.	seth@handylawllc.com;	
Stephan Wollenburg	swollenburg@seadvantage.com;	
Mary McMahon	mmcmahon@seadvantage.com;	
Jim Kennerly	jgifford@seadvantage.com;	
Amy Moses	amoses@utilidata.com;	
Amy Boyd, RI Director, Acadia Center	aboyd@acadiacenter.org;	401-276-0600

Oliver Tully, Acadia Center	otully@acadiacenter.org;	
Amanda Barker	amanda@greenenergyconsumers.org;	
Larry Chretien	larry@greenenergyconsumers.org;	
Nancy Lavin	nlavin@rhodeislandcurrent.com:	

PUC 4-4 Supplemental

Utility Plant Accounting and Standard for Rate Base Treatment

Request:

In response to PUC 1-9, the Company states, "Capital investments in the Company's AMF Business Case and cost-recovery proposal are considered placed in service when the costs have been incurred and the investment is ready for its intended use."

(a) Is this treatment of AMF investments, including when system components are considered to be "in service" and when cost recovery in rates commences, consistent with the ratemaking treatment given to the deployment of AMF assets in other jurisdictions in which PPL operates AMF systems?

(b) If not, please explain the ratemaking treatment utilized for AMF investments in those jurisdictions.

(c) Please provide documentation (orders, etc.) approving any ratemaking treatment identified in (b).

Original Response:

(a) through (c)

Yes, this treatment of when AMF investments are placed into service and when cost recovery in rates commences, is consistent with the accounting and ratemaking treatment given to the deployment of AMF capital assets for PPL Electric Utilities Corporation in Pennsylvania.

Supplemental Response:

For Kentucky Utilities Company and Louisville Gas and Electric Company (together, "LGE/KU"), the Kentucky Public Service Commission ("KPSC") approved cost recovery of the advanced metering infrastructure ("AMI") investment to be addressed after the project was fully implemented. Under the KPSC order, LGE/KU would record the investment in the AMI project as Construction Work in Progress ("CWIP") and accrue an allowance for funds used during construction ("AFUDC") during the projected implementation period of approximately five years. LGE/KU also would record a regulatory liability until its first base rate proceedings following implementation to the extent actual meter reading and field service expenses are less than the forecast test period level embedded into base rate during the 2020 base rate case proceedings. Finally, LGE/KU would record a regulatory asset during the implementation period comprised of three components: (1) operating expenses associated with project implementation; (2) the remaining net book value of electric meters replaced and retired as part of the project; and (3) the difference between AFUDC accrued at the weighted average cost of capital ("WACC") proposed by LGE/KU and the WACC calculated using a strict interpretation of the methodology approved by the Federal Energy Regulatory Commission. See Attachment PUC 4-4-1 Supplemental, beginning on page 15 for the KPSC's LGE Order and Attachment PUC 4-4-2 Supplemental, beginning on page 13 for the KPSC's KU Order.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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

ORDER

Louisville Gas and Electric Company (LG&E) is a jurisdictional electric and gas utility that serves customers in 9 Kentucky counties.[1] LG&E also purchases, stores, and transports natural gas, and distributes and sells natural gas to 330,270 retail customers in all or portions of 17 Kentucky counties.[2] Its most recent general rate case for electric and gas service was Case No. 2018-00295.[3]

BACKGROUND

On October 23, 2020, LG&E filed a notice of its intent to file on or after November 25, 2020, an application for approval of increases in its electric and gas rates, including

[1] *Annual Electric Report of Louisville Gas and Electric Company to the Public Service Commission for the Year Ending December 31, 2020* at 4. *See also* Application at 2.

[2] *Annual Gas Report of Louisville Gas and Electric Company to the Public Service Commission for the Year Ending December 31, 2020* at 4 and 5. *See also* Application at 2.

[3] Case No. 2018-00295, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates* (Ky. PSC Apr. 30, 2019).

changes to its electric and gas tariffs, a Certificate of Public Convenience and Necessity (CPCN) to deploy advanced metering infrastructure (AMI), approval of certain regulatory and accounting treatments, and establishment of a one-year surcredit.[4] On November 25, 2020, LG&E filed its application[5] seeking an increase in electric revenues of $131.1 million, or 11.6 percent per year for the forecasted test period compared to the operating revenues for the forecasted test period under existing electric rates.[6] LG&E also sought an increase in natural gas revenues of $30.0 million, or 8.3 percent per year, for the forecasted test period compared to the operating revenues for the forecasted test period under existing electric rates.[7] LG&E's application included, among other things, new rates and revisions, deletions, and additions to its electric tariffs, all to be effective January 1, 2021.[8] LG&E's requested rate increase is supported by a 12-month fully forecasted test period ending June 30, 2022. The base period consists of the 12 months ending February 28, 2021. As authorized by KRS 278.192(2), this base period begins not more than nine months prior to the date of the filing of the application, and is a period consisting of not less than six months of historical data and not more than six months of estimated data. The monthly residential electric bill increase due to the proposed electric base rates will be 11.81 percent, or approximately $11.74, for an average LG&E customer

[4] LG&E's Notice of Intent.

[5] Also on November 25, 2020, LG&E's sister company, Kentucky Utilities Company (KU), filed a separate application seeking an increase in its electric rates. KU's application is docketed as Case No. 2020-00349.

[6] Application at 3; and Direct Testimony of Kent W. Blake (Blake Testimony) at 20. *See also* LG&E's Customer Notice of Rate Adjustment at 1.

[7] Application at 4; and Blake Testimony at 20. *See also* LG&E's Customer Notice of Rate Adjustment at 1.

[8] LG&E's Customer Notice of Rate Adjustment at 1.

using 894 kilowatt-hours (kWh) of electricity.[9] The monthly residential natural gas bill increase due to the proposed natural gas base rates will be 9.37 percent, or approximately $6.17, for an average LG&E customer using 54 centum cubic feet (Ccf) of natural gas.[10]

Pursuant to an Order issued on December 9, 2020, the Commission found that an investigation would be necessary to determine the reasonableness of LG&E's proposed rates and suspended the proposed rates for a period of six months, pursuant to KRS 278.190(2), from January 1, 2021, up to and including June 30, 2021. The December 9, 2020 Order also established a procedural schedule for processing this case. The schedule provided, among other things, a deadline for requesting intervention, discovery on LG&E's application, intervenor testimony, discovery on intervenor testimony, and rebuttal testimony by LG&E.

The following parties requested and were granted intervention: the Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General); Kentucky Industrial Utility Customers, Inc. (KIUC); Kroger Company (Kroger); Walmart, Inc. (Walmart); Metro Louisville/Jefferson County Government (Louisville Metro); Kentucky Solar Industries Association, Inc. (KYSIA); Sierra Club; United States Department of Defense and all other Federal Executive Agencies (DOD/FEA); and Mountain Association, Kentuckians for the Commonwealth, and Kentucky Solar Energy Society (collectively, Joint Intervenors).

Pursuant to an Order issued on March 29, 2021, informal conferences were held, at the request of LG&E, on April 15 and 16, 2021, to allow the parties to this matter and

[9] Application at 3.

[10] Application at 4.

the KU rate matter an opportunity to discuss the issues and the possible resolution of those issues in the two non-consolidated proceedings. The parties at the informal conferences were able to come to an agreement resolving all of the issues in this proceeding as well as the KU proceeding, except for LG&E's proposed qualifying facility tariff provisions and the net metering proposals. On April 19, 2021, LG&E and KU filed a joint motion requesting leave to file testimony supporting the Stipulation.[11]

The Commission held information sessions and public meetings for the purpose of taking public comments on April 14, 15, and 21, 2021. Due to the COVID-19 state of emergency, the information sessions and public meetings were conducted virtually.

A formal hearing was conducted on April 26, 27, and 28, 2021, for the purposes of cross-examination of witnesses and for the consideration of the Stipulation. LG&E filed responses to post-hearing data requests on May 19, 2021. Post-hearing briefs were filed on May 24, 2021, by LG&E, the Attorney General and KIUC on a joint basis, Louisville Metro, Sierra Club, Kroger, DOD/FEA, Walmart, KYSIA, and Joint Intervenors. Responsive briefs were filed by LG&E, the Attorney General and KIUC on a joint basis, KYSIA, and Joint Intervenors on June 1, 2021. The matter now stands submitted to the Commission for a decision.

LEGAL STANDARD

[11] On May 7, 2021, LG&E and KU filed a Joint Errata to the Stipulation Exhibit 1 (Joint Errata), which had been filed along with the Stipulation on April 19, 2021. LG&E and KU stated that they inadvertently failed to update the AMI rates agreed to in the Stipulation. The Joint Errata contains the agreed to depreciation rates for new AMI software placed in service after June 30, 2020, based on a life of 15 years.

LG&E filed its application pursuant to KRS 278.020; KRS 278.180; KRS 278.190; 807 KAR 5:001, Sections 15–16; and 807 KAR 5:011. The Commission's standard of review of a utility's request for a rate increase is well established. In accordance with statutory and case law, LG&E is allowed to charge its customers "only 'fair, just and reasonable rates.'"[12] Further, LG&E bears the burden of proof to show that the proposed rate increase is just and reasonable, under KRS 278.190(3).

The Commission's standard of review of a request for a CPCN is well settled. No utility may construct or acquire any facility to be used in providing utility service to the public until it has obtained a CPCN from this Commission.[13] To obtain a CPCN, a utility must demonstrate a need for such facilities and an absence of wasteful duplication.[14]

"Need" requires:

> [A] showing of a substantial inadequacy of existing service, involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed or operated.
>
> [T]he inadequacy must be due either to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service.[15]

"Wasteful duplication" is defined as "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an unnecessary

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[12] KRS 278.030; and *Pub. Serv. Comm'n v. Com. ex rel. Conway*, 324 S.W.3d 373, 377 (Ky. 2010).

[13] KRS 278.020(1).

[14] *Kentucky Utilities Co. v. Pub. Serv. Comm'n.*, 252 S.W.2d 885 (Ky. 1952).

[15] *Id.* at 890.

multiplicity of physical properties."[16] To demonstrate that a proposed facility does not result in wasteful duplication, we have held that the applicant must demonstrate that a thorough review of all reasonable alternatives has been performed.[17] The fundamental principle of reasonable least-cost alternative is embedded in such an analysis. Selection of a proposal that ultimately costs more than an alternative does not necessarily result in wasteful duplication.[18] All relevant factors must be balanced.[19]

STIPULATION

The Stipulation reflects the agreement of all of the parties to the instant matter and the KU matter, addressing all of the issues with the exception of the proposed net metering changes (Riders NMS-1 and NMS-2) and the qualifying facility tariff provisions (Riders SQF and LQF). The major provisions of the Stipulation as they relate to LG&E's revenues and rates are as follows:

- LG&E's electric operations revenue will increase by $77.30 million, which reflects a reduction of $51.1 million from LG&E's filed position, as adjusted.[20]

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[16] *Id.*

[17] Case No. 2005-00142, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky* (Ky. PSC Sept. 8, 2005).

[18] *See Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 390 S.W.2d 168, 175 (Ky. 1965). *See also* Case No. 2005-00089, *Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for the Construction of a 138 kV Electric Transmission Line in Rowan County, Kentucky* (Ky. PSC Aug. 19, 2005).

[19] Case No. 2005-00089, *East Kentucky Power Cooperative, Inc.* (Ky. PSC Aug. 19, 2005), final Order at 6.

[20] *See* LG&E's Supplemental Responses to Commission Staff's First Request for Information (Staff's First Request) (filed Feb. 26, 2021), Item 56.

- LG&E's gas operations revenue will increase by $24.2 million, which reflects a reduction of $8.8 million from LG&E's filed position, as adjusted.[21]
- The stipulated level of base-rate revenue increase is the result of discrete adjustments to LG&E's original requested increase as provided in the Stipulation, which provisions are summarized below.
- The agreed-to revenue allocation for LG&E's electric operations is set forth in Exhibit 3 to the Stipulation.
- The agreed-to revenue allocation for LG&E's gas operations is set forth in Exhibit 4 to the Stipulation.
- LG&E commits to a base-rate stay out until July 1, 2025, such that any changes from base rates approved in the instant matter shall not take effect before that date. LG&E's stay out commitment is subject to certain exceptions that are set forth in the Stipulation.

The Stipulation results in the monthly bill of an average LG&E residential electric customer increasing by $7.17, or 7.21 percent.[22] A summary of the adjustments to LG&E's electric operations revenue requirement is as follows:

- <u>Return on Equity</u>. The parties to the Stipulation agreed to a Return on Equity (ROE) of 9.55 percent, applied to capitalization. The result is a revenue requirement reduction of $11.0 million. The Stipulation also provided that the

[21] *Id.*

[22] LG&E's Response to Commission Staff's Post-Hearing Request for Information (filed May 19, 2021) (Staff's Post-Hearing Request), Item 18.

ROE that will apply to LG&E's recovery under its environmental cost recovery mechanism is 9.35 percent for all environmental compliance plans.

- Depreciation Rates. Instead of using the depreciation rates LG&E proposed in its application for Mill Creek 1 and 2 generation units, LG&E agrees to continue to use its currently approved depreciation rates for ratemaking purposes unless and until changed in later Commission proceedings. The other proposed depreciation rates as filed in LG&E's application should be approved for ratemaking purposes. This adjustment results in a revenue requirement reduction of $36.5 million. The stipulated depreciation rates are attached as Exhibit 1 to the Stipulation. On May 7, 2021, LG&E and KU subsequently filed a Joint Errata Stipulation Exhibit 1 – Depreciation Rates which corrects the depreciation rates for "AMI Intangible Plt (software)" and "Micro/Fiber" set forth in Stipulation Exhibit 1 based on a 15-year life.
- Updated Pension and Other Post-Employment Benefits (OPEB) Expenses. The Stipulation reflects LG&E's agreement to use the updated 2021 pension and OPEB projections as the new test-year estimate for purposes of calculating the revenue requirement. The adjustment to update the pension and OPEB expense amounts will result in a revenue requirement reduction of $3.0 million.
- Update Long-Term Debt Rate to Reflect Lower Coupon Rates for New Long-Term Debt in Forecasted Test Year. The parties agree that the coupon rate for new long-term debt included in LG&E's forecasted test year should be reduced from 3.70 percent to 3.40 percent. This adjustment reduces LG&E's proposed revenue requirement by $0.6 million.

- Stipulation Electric Operations Summary. The table below reflects the impact of each adjustment included in the Rate Case Stipulation:

LG&E Increase Requested, as Adjusted[23]	$ 128.4 million
9.55% Return on Equity	(11.0) million
Continue Current Depreciation Rate for Brown 3	(36.5) million
Updated Pension and OPEB Expense	(3.0) million
Update Long-Term Debt Rate	(0.6) million
Total Adjustments to Requested Increase	(51.1) million
Overall Stipulated Increase	$ 77.3 million

The Stipulation results in the monthly bill of an average LG&E residential gas customer increasing by $4.22, or 6.41 percent.[24] A summary of the adjustments to LG&E's gas operations revenue requirement is as follows:

- ROE. The parties to the Stipulation agreed to an ROE of 9.55 percent, applied to capitalization. The result is a revenue requirement reduction of $3.4 million. The Stipulation also provided that the ROE that will apply to LG&E's recovery under its gas line tracker mechanism is 9.35 percent.

- Updated Pension and Other Post-Employment Benefits (OPEB) Expenses. The Stipulation reflects LG&E's agreement to use the updated 2021 pension and OPEB projections as the new test year estimate for purposes of calculating the revenue requirement. The adjustment to update the pension and OPEB expense amounts will result in a revenue reduction of $1.0 million for LG&E.

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[23] *See* LG&E's Supplemental Responses to Staff's First Request (filed Feb. 26, 2021), Item 56.

[24] LG&E's Response to Staff's Post-Hearing Request, Item 18.

- Update Long-Term Debt Rate to Reflect Lower Coupon Rates for New Long-Term Debt in Forecasted Test Year. The parties agree that the coupon rate for new long-term debt included in LG&E's forecasted test year should be reduced from 3.70 percent to 3.40 percent. This adjustment reduces LG&E's proposed revenue requirement by $0.2 million.

- In-Line Inspection Normalization Adjustment. The parties to the Stipulation agree that LG&E's test-year in-line inspection expenses should be normalized based on forecasted expenses for 2021-2025, which results in a revenue requirement reduction of $4.2 million.

- Stipulation Electric Operations Summary. The table below reflects the impact of each adjustment included in the Rate Case Stipulation:

LG&E Increase Requested, as Adjusted[25]	$ 33.0 million
9.55% Return on Equity	(3.4) million
Updated Pension and OPEB Expense	(1.0) million
Update Long-Term Debt Rate	(0.2) million
In-line Inspection Normalization	(4.2) million
Total Adjustments to Requested Increase	(8.8) million
Overall Stipulated Increase	$ 24.2 million

The Stipulation also reflects the following terms as agreed to by the parties to this matter.

- LG&E should recover in electric base rates its normalized plant outage expenses, as requested in its application. Effective July 1, 2021, LG&E will not

[25] *See* LG&E's Supplemental Responses to Staff's First Request (filed Feb. 26, 2021), Item 56.

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 this proceeding.

- The proposed AMI project should be approved with stipulations on the recovery of the project and how savings will be calculated.
- LG&E should be authorized to establish a retirement rider that would recover any remaining net book value and decommissioning costs related to Mill Creek 1 and 2. The retirement costs would be recovered on a levelized basis over 10 years from the retirement date and include carrying charges of the full weighted average cost of capital (WACC). Collections would be offset by depreciation expense for the retired units included in base rates.
- The parties to the Stipulation also agreed to the revenue allocation and rate design for LG&E. The Stipulation provides that the allocations of the increases in annual revenue and the rate design for LG&E as set forth on the schedules designated Stipulation Exhibit 3 and 4 is fair, just and reasonable. The Stipulation also provides that the current Basic Service Charges approved by the Commission in Case No. 2018-00295 for residential electric and gas service should remain unchanged. This agreement also includes a one-year economic relief surcredit of $38.9 million to LG&E electric customers and $2.7 million to LG&E gas customers.[26]

[26] Application, paragraph 17. The surcredit includes the remaining fees from the refined coal facility agreements, the remaining unprotected excess accumulated deferred income taxes, and the payment received by LG&E in connection with a disputed electric service territory matter.

- As shown in Stipulation Exhibit 6, LG&E will reduce its proposed monthly LED conversion fees under Rate LS to $4.62. Also as shown in Stipulation Exhibit 6, LG&E will add a new LED offering to Rate LS to replace its current 100W HPS Cobra offering. LG&E commits to conduct a competitive bidding process for street lighting fixtures every five years and will complete such a competitive bid process prior to LG&E's filing of the next general adjustment of base rates. LG&E also commits to have its information technology personnel work with their Louisville Metro counterparts to explore opportunities to allow streetlight outage notifications from Louisville Metro to flow more directly through to LG&E.
- LG&E agrees to work with its coal-mining customers regarding possible economic development options under LG&E's existing tariffs. Any such option will ensure that the new rate will provide a contribution to the recovery of fixed costs and will be flexible and time-limited. To the extent any such mutually agreed economic development options require Commission approval, LG&E commits to seek the necessary approval.
- LG&E commits to engage in a stakeholder process using its existing Demand-Side Management (DSM) Advisory Committee for its next DSM filing to consider and evaluate Peak-Time Rebates and an on-bill financing program.
- LG&E's current annual shareholder contributions for low-income assistance will be increased by the same percentage as the overall increase in revenue requirement resulting from this proceeding.

ANALYSIS AND FINDINGS

As discussed above, the Commission's statutory obligation when reviewing a rate application is to determine whether the proposed rates are "fair, just and reasonable."[27] While numerous intervenors with significant experience in rate proceedings and collectively representing a diverse range of customer interests have participated in this case, the Commission cannot defer to the parties as to what constitutes fair, just and reasonable rates. The Commission must review the record, including the stipulations, and apply our expertise and knowledge to make an independent decision as to the level of rates, including terms and conditions of service as well as rate design, that should be approved.

To satisfy its statutory obligation in this case, the Commission has performed our traditional ratemaking analysis, which consists of reviewing the reasonableness of each revenue and expense adjustment proposed or justified by the record, along with a determination of a fair ROE.

Stipulation

Based upon our review of the Stipulation, the attachments thereto, and the case record, including intervenor testimony, the Commission finds that, with the modifications as discussed below, the Stipulation is reasonable and in the public interest. The Commission finds that the Stipulation was the product of arm's-length negotiations among knowledgeable, capable parties and should be approved as modified. Such approval is based solely on the reasonableness of the Stipulation and does not constitute a precedent on any individual issue.

Stay Out Provision

[27] KRS 278.030(1).

The Stipulation provides that LG&E will commit to a base-rate "stay out" until July 1, 2025, such that any changes from base rates approved in the instant matter will not take effect before that date. Stated otherwise, LG&E may file base-rate applications during 2024, but the proposed base rates should not take effect before July 1, 2025. LG&E's agreement to not file a base rate application until 2024 so that the proposed base rates will not take effect until on or after July 1, 2025, is subject to the following four exceptions:

1. LG&E retains the independent right to seek Commission approval to establish deferral accounting for certain categories of expenses that have historically been approved for regulatory asset treatment by the Commission.

2. LG&E retains the right to seek emergency rate relief under KRS 278.190(2) to avoid a material impairment or damage to its credit or operations.

3. The stay out provision does not apply to the operation of any of LG&E's cost-recovery surcharge mechanisms and riders at any time during the term of the stay out, including any base-rate roll-ins, which are part of the normal operation of such mechanisms.

4. If a statutory or regulatory change, including but not limited to federal tax reform, affects LG&E's cost recovery, LG&E may take any action it deems necessary in its sole discretion, including but not limited to, seeking rate relief from the Commission.

The Commission finds that this stay out provision and the enumerated exceptions to the stay out are reasonable subject to the following modification: LG&E should provide the Commission with at least 30 days' notice and formally seek Commission approval to seek emergency rate relief under KRS 278.190(2) or to seek rate relief due to a statutory or regulatory change affecting LG&E's cost recovery, and the request should be supported by evidence that these triggering events will have a material financial impact on LG&E's financial position.

AMI

The parties to the Stipulation agreed that LG&E's request for a CPCN for the AMI project and other AMI-related relief requested in LG&E's application should be granted. The Stipulation also encompassed the parties' agreement to the ratemaking treatment associated with the implementation and deployment of the AMI project, including using "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 the result that customers will not sustain an increase in the combined revenue requirements associated with implementing the AMI project."[28] The Stipulation further provided that LG&E will work with Walmart and other interested parties to improve the functionality of customer usage data, including evaluating the potential for implementing Green Button Connect My Data functionality and allowing customers with multiple locations to obtain their usage data through a single download.

Having reviewed the record, the Commission finds that the AMI-related provisions of the Stipulation are reasonable based upon the below discussion and that our approval is conditioned upon LG&E obtaining approval from the Federal Energy Regulatory Commission (FERC), if FERC approval is necessary, for the accounting treatment being sought by LG&E with respect to the proposed accrual of Allowance for Funds Used During Construction (AFUDC) during the AMI implementation period. Within 20 days of the date

[28] Stipulation Testimony of Kent W. Blake (Blake Stipulation Testimony), Exhibit KWB-1 at 11.

of this Order, LG&E should file with the Commission notice whether FERC approval is necessary for the AFUDC accounting treatment and an estimated timeline for requesting and receiving FERC approval.

The Commission emphasizes that, but for the expectation of savings projected by LG&E in connection with the full deployment of the AMI project, the CPCN would not have been authorized by this Commission. Our determination that LG&E satisfied the legal standard to grant a CPCN for the AMI project arises from a finding of need based upon an economic analysis only, and not due to the obsolescence of the existing meters. We note that LG&E failed to evaluate a scenario in which the AMI deployment is delayed or a scenario in which reactive replacements would be reduced in order to minimize the impact of the undepreciated amounts associated with the existing meters that would be retired early.

As LG&E noted, a CPCN is not a finding that a utility can recover the construction costs in rates; the Commission will review the reasonableness of the construction costs in a future rate case.[29] Additionally, in approving the CPCN for the proposed AMI systems for LG&E and its sister entity KU, the Commission would like to make clear that this investment presents a significant shift and opportunity for Kentucky's largest utilities. Having an AMI system, particularly one coupled with the numerous "smart grid" investments that LG&E has or intends to make in the near future, represents a fundamental change for the utility. The Commission cautions LG&E that it expects the utility to not merely make this investment and miss the boat on all of the offerings this

[29] LG&E/KU's Response to Commission Staff's Post-Hearing Request for Information (Staff's Post-Hearing Request) (filed May 19, 2021), Item 9.

change presents. The Commission expects that, given many of the benefits of AMI represent customer savings, occasionally at the expense of LG&E earnings, there will be inherent tension as to whether LG&E is compelled to make offerings beneficial to customers after LG&E has received the ongoing benefit from the return of and on the AMI investment. The Commission reminds LG&E that the only reason the Commission approved this CPCN is the net benefit to customers. Nevertheless, merely meeting the net benefits when additional customer benefits from AMI systems are available would not result in rates that are fair, just and reasonable, nor service that is adequate, efficient and reasonable. To that end, the Commission further finds that additional requirements are necessary to ensure that the benefits of the investment and those proffered by LG&E are fully and completely captured such that ratepayers will not have any rate impact from the implementation and deployment of the AMI project and that customers receive the full benefit of the capital expended for the public's convenience.

- LG&E shall file quarterly reports updating the status of the AMI project by detailing the status of the implementation and deployment of the project, adherence to budgets, adherence to timeliness, any significant change orders, number of AMI meters implemented, and number of non-AMI meters removed and retired. The first of these reports shall be filed September 30, 2021.
- LG&E shall also establish clear and sufficient baseline on all benefits that includes items set forth in Appendix F, and affirmatively show that the projected savings can be achieved on an incremental basis. The first filing of this requirement shall be in LG&E's next base rate case.

- LG&E shall, for each item set forth in Appendix F, provide detailed plans on how it will achieve the benefits and how it will periodically determine if it is maximizing those benefits. Those periodic reviews shall determine the success and failures for each item to-date, and LG&E should clearly indicate what progress it is making to maximize those benefits. The first filing of this requirement shall be June 30, 2022, and annually thereafter.
- LG&E shall develop and implement a prepay program as well as develop DSM programs, including those that specifically target low-income customers. The prepay program shall be proposed in LG&E's next base rate case. The Commission points LG&E to the final order in Case No. 2019-00277[30] in which the Commission noted the potential for the Duke Energy Kentucky, Inc.'s (Duke Kentucky) Peak Time Rebate Pilot Program and stated the following:

> Using AMI metering for more than just billing purposes is something that not only Duke Kentucky, but all utilities should consider to maximize the benefits of smart meters. With AMI meters, programs such as Time of Use rates and prepay programs can be easily added as a rate option. Such rate options contribute to lower peak demand and help avoid costly capital investments or free up power to be sold on the market for additional revenue. The Commission encourages Duke Kentucky to learn from this pilot and modify the program so to maximize the benefit. The Commission further urges Duke Kentucky to study the incentive, or rebate, to ensure that the "carrot" is high enough to encourage behavioral changes that are impactful.[31]

[30] Case No. 2019-00277, *Electronic Application of Duke Energy Kentucky, Inc. to Amend Its Demand Side Management Programs* (Ky. PSC Apr. 27, 2020).

[31] Case No. 2019-000277, *Duke Energy Kentucky, Inc.* (Ky. PSC Apr. 27, 2020), Order at 14–15.

- LG&E shall, on or before its next base rate case, file with the Commission proposed Electric Vehicle tariffs for home or business charging. The tariff should be cost based, but should incent off-peak electric vehicle charging.
- LG&E shall create detailed plans for customer engagement of its AMI systems. This should include LG&E's planned customer engagement before, during and after AMI deployment, including through the system's end of useful life. This plan shall be filed with the Commission by June 30, 2022, and updated and submitted annually thereafter.
- LG&E shall create detailed plans on AMI obsolescence and replacement strategies. These plans should identify, at a minimum, risks and solutions to early obsolescence, opportunities for greater cross-system compatibility, and successor technologies, including hardware and software, in order to extend the life of as many portions of the proposed AMI systems as reasonably practical. The initial plan on AMI obsolescence and replacement strategies shall be filed with LG&E's next base rate case.
- LG&E shall create detailed plans on identifying outages and how the AMI systems will facilitate notification and communication of information with customers regarding outages. This shall include estimated times of repair. These plans shall include the AMI systems' interaction with LG&E's other "smart grid" investments, including an outage management system. The initial plan shall be filed with the Commission by June 30, 2022 and updated every other year thereafter.

- In addition to the Stipulation term that LG&E will work with Walmart and other interested parties to improve the functionality of customer usage data, including evaluating the potential for implementing Green Button Connect My Data functionality and allowing customers with multiple locations to obtain their usage data through a single download, the Commission finds that LG&E shall also be required to receive certification of its Green Button Connect My Data offering, to residential and non-residential customers alike. LG&E shall file with the Commission proof of its Green Button Connect My Data certification by June 30, 2023.
- LG&E shall create a detailed plan for reducing the frequency and amounts of its tariffed non-recurring charges resulting from it proposed AMI systems.
- LG&E shall include detailed discussions in each iteration of its Integrated Resource Plan that explain how it is using the information created by the AMI systems to create additional data or study the remainder of the utility's system. The Commission expects LG&E will study, at the least, how the information created by the AMI systems can be used to benefit: voltage regulation, power quality, asset management, distribution system investment and utilization, load forecasting (at least at the circuit level, if not more granular), peak reduction (generation, transmission and distribution peaks, both coincident and non-coincident), transmission investment and utilization, and important in this matter, the calculation of all avoided cost categories the Commission indicates we look to use in determining NMS-2 and QF compensation.

- Finally, in its next base rate case LG&E shall indicate any other intended uses of data created by its proposed AMI systems.

Retired Asset Recovery Rider (RARR)

The Commission finds that although LG&E has the discretion to determine when a generation unit should be retired, it is the Commission that is vested with the authority to determine the ratemaking treatment resulting from that retirement decision. Based upon the case record, the Commission determines that the Stipulation provision regarding the RARR is reasonable subject to the clarifying modification that LG&E has the burden of proof to establish the proper level of the remaining net book value and decommissioning costs associated with the retirement of Mill Creek Units 1 or 2, and the appropriateness of recovering those costs.

ROE

In its application, LG&E used multiple models to develop its ROE recommendation including the Discounted Cash Flow (DCF) model, both the Capital Asset Pricing Model (CAPM) and the Empirical Capital Asset Pricing Model (ECAPM), a risk premium analysis (RP), and an analysis to the expected rates of return for utilities (Expected Earnings).[32] Based upon the results of the analyses, LG&E recommended an ROE range of 9.4 percent to 10.6 percent with a midpoint of 10.0 percent.[33] LG&E maintained that an ROE of 10.0 percent is fair, just and reasonable, given market expectations and the economic requirements necessary to maintain its financial integrity and to support its

[32] Direct Testimony of Adrien M. McKenzie (McKenzie Direct Testimony) at 7.

[33] *Id*. at 7. Note that the ROE results include a floatation cost and company size adjustments.

ongoing capital investment requirements.[34] Intervenors including the Attorney General and KIUC jointly, Walmart, and the DOD/FEA provided direct testimony and were subject to discovery by all parties.

Per Section 2.2A of the Stipulation,[35] all parties agreed that the revenue requirement increase for LG&E's electric operations will reflect a 9.55 percent ROE as applied to LG&E's capitalization and capital structure of the proposed electric revenue requirement increases and subsequently adjusted by LG&E's updated filings and the capitalization effects of adjustments in the Stipulation.[36] Under the Stipulation, LG&E's overall base rate electric revenue requirement increase resulting from stipulated adjustments is $115.9 million.[37] The use of an ROE of 9.55 percent reduces LG&E's original requested revenue requirement by $16.7 million.[38] In addition, a 9.35 percent ROE is applied to LG&E's environmental cost recovery mechanism for all environmental compliance plans.[39] The following table presents the recommended ROEs from LG&E and the Intervenors and the methods used to support each parties' recommendations:

Party	Recommendation	Methods
LG&E	10.00%	DCF, CAPM, ECAPM, RP, Expected Earnings

[34] *Id.*

[35] *See* Blake Stipulation Testimony, Exhibit KWB-1 at 5–6.

[36] *Id.* at 5.

[37] *Id*. at 7.

[38] *Id.*

[39] *Id*. at 6.

Attorney General/KIUC[40]	9.00%	DCF, CAPM, RP
Walmart[41]	no higher than 9.725%	Survey of awarded ROEs
Joint Intervenors[42]	9.2%-9.3%	Survey of ROE trends
DOD/FEA[43]	9.30%	DCF, CAPM, RP
Stipulation		
Electric and Gas	**9.55%**	
Environ Surcharge	**9.35%**	

For the reasons discussed below, the Commission finds that an ROE of 9.55 percent for LG&E's electric and gas operations is unreasonable and higher than that required by investors in today's economic climate, and that this provision of the Stipulation should be modified. Based on the evidence provided though, the Commission finds that the stipulated 9.35 percent ROE for LG&E's Environmental Surcharge mechanism and Gas Line Tracker is reasonable.

The Commission continues to believe that it is appropriate for utilities to present and the Commission to evaluate multiple methodologies to estimate ROEs, and that it is the Commission's role to analyze the various approaches as presented by the parties. As enumerated in the table above, LG&E and the parties utilized multiple methods to estimate and support their recommended ROEs, which themselves represent a synthesis of a broader range of parties' ROE estimates. The recommended ROE estimates range

[40] *See* Direct Testimony of Richard A. Baudino (filed March 5, 2021) at 37.

[41] *See* Direct Testimony of Lisa V. Perry (Perry Testimony) (filed March 5, 2021) at 13.

[42] *See* Direct Testimony of James Owen (filed March 5, 2021) at 28.

[43] *See* Direct Testimony of Christopher C. Walters (filed March 5, 2021) at 3.

from a low of 9.0 percent to a high of 10.0 percent. At the conclusion of settlement discussions, all parties jointly recommended a 9.55 percent ROE for LG&E's electric and gas operations and 9.35 percent to be applied to the environmental surcharge mechanism.

The Commission notes that the recent regulatory decisions have shown a downward trend. S&P Global Market Intelligence reported that the 2019 average awarded ROE for vertically integrated utilities was 9.73 percent and 9.64 percent for all utilities. For 2020, the average awarded ROEs for vertically integrated utilities was 9.55 percent and 9.39 percent for all utilities.[44] These trends in allowed ROE generally follow the underlying trends of the financial information used in multiple ROE methodologies, such as risk free and debt rates. In addition, the Commission submits its two most recent fully litigated, vertically integrated rate cases 2019-00271[45] and 2020-00174[46]. In 2019-00271, the Commission authorized an ROE of 9.25 percent for Duke Kentucky. In 2020-00174, the Commission authorized an ROE of 9.30 percent for Kentucky Power Company's (Kentucky Power) electric operations.

The Commission notes that rating agencies cite several factors that contribute to lower overall risk for LG&E, including a constructive regulatory framework, an environmental cost recovery mechanism, pass through fuel cost recovery, and purchased

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[44] *See* Perry Testimony Exhibit LVP-3 at 5.

[45] *See* Case No. 2019-00271, *Electronic Application of Duke Energy Kentucky, Inc. for 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief* (Ky. PSC Apr. 27, 2020), final Order at 46.

[46] *See* Case No.2020-00174, *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* (Ky. PSC Jan. 13, 2021), final Order at 50.

power cost recovery riders.[47] However, the Commission recognizes that there are other factors leading to higher risk affecting LG&E than otherwise similar-situated electric utilities. First is increased financial risk. LG&E's capital spending on new facilities as well as maintenance and repair is significant and anticipated to total approximately $2.3 billion or about 34 percent of its net book value of property, plant, and equipment through the 2020-2024 period.[48] Second is LG&E's increased environmental risk due to its lack of fuel diversity. A significant portion of LG&E's generation capacity is coal fired and has elevated carbon risk.[49] Third, the economy overall is slowly recovering from the effects of COVID-19. As more people become vaccinated and the economic recovery progresses, it is reasonable to expect the economy to return to more normal employment, interest rate, and inflation levels. Finally, the Commission views the stipulated four-year stay out provision as a significant facet of the Stipulation and a risk factor.

Having considered and weighed all the evidence in the record, the Commission finds that the stipulated 9.55 percent ROE significantly overstates the risks that LG&E faces and thus overstates the allowed return for investors. Nevertheless, in accordance with the underlying financial data provided in this matter and taking into account the risk noted above, the Commission finds that a 9.425 percent ROE for LG&E's electric and gas operations is fair, just and reasonable, which results in a revenue requirement decrease from electric operations of $3.19 million from that proposed in the Stipulation and a

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[47] *See* for example LG&E's Response to the Attorney General and KIUC's First Request for Information (Attorney General and KIUC's First Request) (filed Jan. 22, 2021), Item 104, Attachment 3 at 1, 4 and 5 and Attachment 5 at 3 and 5.

[48] McKenzie Direct Testimony at 14.

[49] LG&E's Response to the Attorney General and KIUC's First Request, Item 104, Attachment 3 at 6.

revenue requirement decrease from gas operations of $0.94 million from that proposed in the Stipulation.

Finally, with regard to ROE studies and analyses generally, the Commission cautions all parties against unreasonably removing or ignoring "outlier" data. Analyses should not discount data that is merely "too high" or "too low," especially given the number of actions that can be taken to account or counteract for that data, such as averaging or even conducting multiple alternative methodologies. Although there may be merit in excluding truly outlier data in financial or economic modeling and analyses, result-oriented exclusions of data points that are not beyond the realm of reasonableness are inappropriate. The Commission cautions all parties that ROE analyses that exclude results as merely being "too high" or "too low," without adequate support, will be provided less weight in the Commission's determination of an appropriate return.

Forecasted Legal Fees

When asked to provide details concerning forecasted legal fees, LG&E refused on the basis that the disaggregated information is attorney work product and protected from disclosure.[50] The Commission recognizes and appreciates LG&E's right to assert its privilege to not disclose certain details of the legal work performed by its attorneys. However, when a utility seeks to recover an expenditure in its rates, the Commission is obligated to review that expenditure to verify that it is just and reasonable. The information LG&E claimed is privileged is the exact type of information necessary for the Commission to determine the appropriateness of allowing recovery of the "anticipated" costs. Without an understanding of the matters *and* the expected expense of participating

[50] LG&E's Response to Staff's Post-Hearing Request (filed May 19, 2021), Item 14.

in them, any rate regulator would struggle to determine if the amounts requested to be recovered from customers is reasonable. Ignoring for a moment the anticipated amount of each matter, the Commission effectively has no information available to us to determine whether the matters presented are the type for which the Commission should permit attendant costs to be recovered in rates. For instance, the costs of defending claims of willful or negligent action by a utility or its agents may not necessarily be reasonably recovered from customers, especially in instances where a utility's conduct leads to a judgment against it. LG&E's "Litigation Matters," for example, contain information that merely states the general categories of the anticipated legal cases or the plaintiffs in ongoing litigation. In fact, LG&E is the defendant or respondent in all of the matters that indicate a plaintiff. To, at a minimum, identify the claim or cause of action presented by the complaint in each case certainly does not infringe on the items LG&E cited (unpersuasively) in support of its objection, such as the opinions, conclusion or legal theories of LG&E's own counsel.

In this instance, we are unable to determine from the evidence of record the reasonableness of LG&E's forecasted legal fees. Therefore, the Commission finds that $2.9 million and $1.0 million[51] should be disallowed for electric and gas operations, respectively, which results in a revenue requirement reductions of $2.9 million and $1.0 million.

Edison Electric Institute (EEI) Dues

As part of its proposed rates in this matter, LG&E sought recovery of its anticipated EEI dues, net of a reduction identified by EEI that is reflective of "'lobbying and political

[51] LG&E's Response to Commission Staff's Fifth Request for Information (filed Apr. 1, 2021), Item 2.

activities' under section 162(e)" of the Internal Revenue Code (IRC).[52] In determining whether it should exclude or include a test-year amount of EEI dues, LG&E stated that it did not rely on any studies, but instead "relie[d] upon information provided on the invoices received" from the organization.[53] A letter LG&E provided from Emily Sanford Fisher, EEI's General Counsel and Corporate Secretary, explained that the amount identified by EEI for "lobbying and political activities" is calculated pursuant to Section 162(e) of the IRC. Section 162(e) of the IRC denies the ability of taxpayers to deduct certain lobbying and political expenditures. Ms. Fisher's letter went on to note than the activities identified by EEI under Section 162(e)'s "lobbying and political activities" categories "captures not only federal lobbying, but also state and grassroots lobbying and political activity."[54] Finally, the letter noted that EEI does not separately account for activities that could be described as "regulatory advocacy, and public relations."[55]

Regulatory advocacy and public relations, in addition to legislative advocacy, are categories of costs incurred by EEI and passed onto LG&E for which the Commission has explicitly denied recovery from customers.[56] In that matter the Commission noted that LG&E's "description of regulatory advocacy appears to be a form of lobbying activity,

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[52] LG&E's Response to Attorney General and KIUC's Joint Supplemental Request for Information (filed Feb. 19, 2021), Item 42, Attachment 2.

[53] LG&E's Response to the Attorney General and KIUC's First Request for Information (filed Jan. 22, 2021), Item 94.

[54] LG&E's Response to Attorney General and KIUC's Second Request for Information, Item 42, Attachment 2.

[55] *Id*.

[56] Case No. 2003-00433, *An Adjustment of the Gas and Electric Rates, Terms, and Conditions of Louisville Gas and Electric Company* (Ky. PSC Jun. 30, 2004), Order at 51.

which the Commission has not included for rate-making purposes in previous cases."[57] Based on our experience in this matter, we continue to hold this view.

In furtherance of its request to seek recovery of EEI dues, net of the amount removed pursuant to Section 162(e), LG&E argued that it "excluded the appropriate amount of unrecoverable dues based on the information provided from EEI, which is the same approach the Commission approved in Case No. 2020-00174 in January 2021." Although the Commission did approve a certain amount of EEI dues as recoverable from customers in Case No. 2020-00174, for the following three reasons, the Commission denies recovery of all test-year EEI dues in this matter. First, as LG&E should know, it has the affirmative burden of proof in this matter as to whether its proposed rates are fair, just and reasonable. Merely incurring, or expecting to incur, an expense is not itself a sufficient basis for the recovery of that expense from customers in rates that are fair, just and reasonable. If a utility's mere incurrence of a cost deemed it reasonable for recovery, half of the statutory scheme in KRS Chapter 278 would have no need to exist. A focus only on the amount of EEI dues *not* recoverable in rates misses the point. LG&E's affirmative burden is what level of EEI dues *is* recoverable from customers.

The second and third reasons for the Commission's denial of all EEI dues are related to the first, and both reasons are the result of intervening activities. Had both of the other two activities occurred prior to January 2020, the Commission would have denied all EEI dues for Kentucky Power. The first of these intervening actions is EEI's actual regulatory advocacy before the Commission, including in Kentucky Power's recent matter, Case No. 2020-00174. In two sets of written comments and twice in oral

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[57] *Id*.

comments, agents of EEI advocated directly to this Commission the organization's interests, concern and suggestions regarding the Commission's implementation of rates pursuant to Senate Bill 100, An Act Related to Net Metering.[58] This case also deals with SB 100.

The letter from Ms. Fisher on behalf of EEI provides more explanation of what is and what is not included in the Section 162(e) adjustment than the Commission has received before. Based on the explanation in the EEI letter, coupled with EEI's actual regulatory advocacy, the Commission finds that EEI is engaging in activity the Commission has previously denied recovery of expenses for and, and for which LG&E seeks recovery of in this matter. The newly explained information in Ms. Fisher's letter, including the explanation of what *is not* included in the amount excluded by EEI, is the third basis for denial of the test-year EEI amount. Without any evidence as to the amounts included in the EEI dues related to the inappropriate activities discussed above, the Commission finds LG&E has not met its burden of proof as to the reasonableness of recovery of any of the proposed EEI dues. The Commission's determination is not a finding that the remainder of the EEI dues is reasonable. As previously noted, LG&E has the affirmative burden of proof as to the reasonableness of expenses. Merely identifying a portion of costs incurred that a utility does not seek recovery of does not meet the threshold of reasonableness as to the remainder of expenses. Given their public-facing activities, this is even more so for organizations that require dues. Therefore, the

[58] *See* Case No. 2020-00174, *Electronic Application of Kentucky Power* Company, November 13, 2020 letter from Philip D. Moeller, Public Comments,; April 22, 2021 letter from Shelby A. Linton-Keddie, Public Comments.

Commission has reduced jurisdictional miscellaneous general expenses by $0.4 million,[59] which results in a revenue requirement decrease of $0.5 million.

Other Adjustments to Stipulation

The Commission will reduce the amortization of rate case expense to reflect LG&E's actual expenses, which results in revenue requirement reductions of $0.04 million and $0.01 million, for electric and gas operations respectively.[60] Finally, the stipulated revenue requirement reduction related to the forecasted long-term debt rate appears to be based on the adjustment recommended by the Attorney General and KIUC's witness, Lane Kollen, which used an adjusted rate base instead of capitalization.[61] The Commission finds that the adjustment should be based on capitalization, consistent with the reduction of the ROE, which results in a revenue requirement reduction of $0.07 million for electric operations only.[62] A summary of the Commission's adjustments to the Stipulation for both gas and electric operations are shown in Appendix E.[63]

REVENUE ALLOCATION AND RATE DESIGN

Cost of Service Study (COSS)

In the development of the proposed rates, LG&E relied on its filed COSS as a guide for both revenue allocation and unit charges. For its COSS, LG&E applied the loss of load probability (LOLP) methodology. Additionally, LG&E filed a 12 Coincident Peak

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[59] Application, Schedule F-1.

[60] *See* LG&E's Supplemental Responses to Commission Staff's First Request for Information (filed Feb. 24, 2021), Item 14d.

[61] *See* Direct Testimony of Lane Kollen at 103.

[62] *See* Appendices C and D, attached to this Order, for cost of capital related adjustments to LG&E's revenue requirement for electric and gas operations, respectively.

[63] Amounts from the Stipulation differ due to rounding.

(12CP) and a 6 Coincident Peak (6CP) COSS in accordance with Case No. 2018-00295 where the Commission found that LG&E should file an alternative COSS along with the LOLP in the company's next base rate case.[64] A utility's LOLP is the probability that a utility system's total demand will exceed its generation capacity. In Case No. 2018-00295, the Commission noted that it did not explicitly reject the LOLP methodology, but recognized that the LOLP methodology had not been adopted in other regulatory jurisdictions, the probabilities are estimates based upon a proprietary software package, and that the LOLP methodology was novel.[65]

Several intervenors argued against the use of the LOLP as a COSS methodology. According to the Attorney General's expert witness, Glenn A. Watkins, the LOLP methodology is the statistical evaluation of the probability of a utility not being able to meet its load obligation at any point in time given its demand and supply resources. Mr. Watkins maintained that in reality, given the excess capacity within the LG&E/KU combined system,[66] there is no reasonable possibility that load requirements would not be met.[67] Mr. Watkins further argued that the LOLP analysis does not reasonably reflect the manner in which generation costs are incurred as the LOLP method assigns generation-related costs to individual classes and gives no consideration to the manner in which generation resources were planned, designed, or installed.[68] Mr. Watkins further

[64] Case No. 2018-00295, *Louisville Gas and Electric Company* (Ky. PSC Apr. 30, 2019), Order at 19.

[65] *Id*. at 18–19.

[66] To the extent LG&E and KU plan and operate each of their generation systems as a combined system to meet load requirements, the Commission will refer to both companies in this section.

[67] Direct Testimony of Glenn A. Watkins (Watkins Testimony) at 22.

[68] Watkins Testimony at 27.

questioned whether the LOLP method applied by LG&E follows the LOLP methodology set forth in the National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manuel and requested that the Commission reject the model.[69]

On behalf of KIUC, Steven J. Baron requested that the Commission reject LOLP methodology, arguing that LOLP methodology has not been adopted by any other utility regulatory agency.[70] Mr. Baron further stated that due to that fact that the LOLP method relies on a projection of 8,760 hours of load data for each rate class, the model is overly data intensive and thus raises reliability issues especially in light of the fact that the models are projecting up to 18 months in the future.[71] Mr. Baron did not find issue with the 12CP or 6CP COSSs, but suggested that the Commission rely on the 6CP COSS noting that it is a more traditional methodology and reasonably reflects cost causation associated with the need for generation resources.[72] Mr. Baron further noted that although LG&E's COSS witness, Steven Seelye, recommends adoption of the LOLP study; he also acknowledged that the 6CP methodology is more accurate than the 12CP methodology and the 6CP COSS recognizes the factors that impact the need for generation resources.[73]

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[69] Watkins Testimony at 27–28. Mr. Watkins also requests that the Commission reject the 6 CP and 12 CP COSS, but at issue here is the LOLP COSS.

[70] Direct Testimony of Stephen J. Baron (Baron Testimony) at 7 and 16.

[71] Baron Testimony at 7 and 15.

[72] Baron Testimony at 7 and 20.

[73] Baron Testimony at 13.

Finally, the DOD/FEA's witness, Michael P. Gorman, also objected to the LOLP methodology. Similar to Mr. Baron, Mr. Gorman asserted that the model is highly complex, data intensive, and less transparent.[74] Mr. Gorman supported the use of the 6CP method as it ties contributions to the system peak demands in the summer and winter periods that then align with LG&E's demand charges outlined in on-peak and off-peak periods, and base, intermediate, and peak period rates.[75] Mr. Gorman further noted, similar to Mr. Watkins, that the NARUC Electric Utility Cost Allocation Manual casts doubt on the reliability and effectiveness of the use of LOLP methodology as a proper cost of service and rate design methodology.[76]

LG&E agreed that the 6CP is reasonable but also argued for the LOLP methodology.[77] LG&E admitted that the LOLP is more complex, but asserted that it is a more robust model since it analyzes loads for all hours of the year and thus provides a more accurate reflection of the cost to service each rate class.[78] LG&E further asserted that both PJM and MISO use the loss of load expectation method, which is determined by the timing of LOLP hours for calculating the amount of generation resources needed in their capacity markets.[79]

The Commission recognizes the arguments related to the LOLP methodology but still supports its comments from the 2018 Rate Case. The Commission concludes that

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[74] Direct Testimony of Michael P. Gorman at 33.

[75] *Id*.

[76] *Id*. at 34.

[77] Rebuttal Testimony of William Steven Seelye at 101.

[78] *Id*. at 82.

[79] *Id*. at 83.

due to the immense data inputs, much of which is an estimated forecast, the model raises questions regarding reliability. In addition, LG&E has submitted a LOLP COSS in its last three rate cases, and during that time, no other regulatory commission has approved such a study. Based on the foregoing, the Commission finds that the LOLP methodology, and in particular the modified version proposed by LG&E, is not reasonable for use in allocating production-related expenses. Therefore, LG&E shall not depend on this study as a guide for revenue allocation and rate design in future rate case filings. LG&E shall file a cost of service study in its next base rate case that uses a methodology approved by NARUC.

Rate Adjustment

In setting the rates shown in Appendix B, the Commission maintained the basic service charges for each class that was included in the Stipulation. The reduction in LG&E's stipulated revenue increase as found reasonable herein was allocated to the energy charges of those customer classes for which revenue increases were proposed in the Stipulation for both electric and gas. The reduction to each class's proposed revenue increase was approximately in proportion to the increase set forth in the Stipulation, accounting for minor differences due to rounding. For LG&E's average electric residential customer, the average monthly bill will increase $6.75 or 6.79 percent and $3.55 or 5.40 percent for the average residential gas customer.

NET METERING

As noted above, the Stipulation did not address LG&E's proposed net metering tariffs, NMS-1 and NMS-2.

Based upon changes in Kentucky law resulting from Senate Bill 100, An Act Related to Net Metering, which took effect on January 1, 2020, LG&E proposed to close the current net metering service tariff, renamed NMS-1 in this proceeding, to new customers, and established a new tariff, NMS-2. LG&E, the Attorney General/KIUC, KYSIA, Joint Intervenors, and Sierra Club presented evidence, to differing degrees, regarding net metering through written testimony, discovery responses, cross-examination at the formal hearing, and in post-hearing briefs.

As discussed below, the Commission will defer a decision on NMS-1 and NMS-2 so that additional information can be filed into the record regarding the NMS-2 export compensation rate. The Commission notes that LG&E has already or anticipates spending tens-of-millions of dollars on advanced distribution management solutions (ADMS), Distributed Energy Resource Management Systems (DERMS) (even though the penetration of resources on the LG&E system is miniscule), SCADA and SCADA-related distribution investments, and Distribution Automation and Volt/Var Optimization, all in addition to the proposed AMI project. A primary purpose of much of this investment is to accommodate a dynamic distribution system, particularly one with increasing penetrations of distributed resources. Additionally, the basis for some of these investments, such as voltage regulation, can be accomplished by other means like distributed resources. To ignore the impact or benefit of these investments, or alternatives to these investments, in determining the NMS-2 export compensation rate is unreasonable. Because that is what LG&E is doing in this matter, the Commission questions whether additional scrutiny or investigation of LG&E's investment in "smart grid" technology may be necessary.

NMS-2 Export Compensation Rate

Although LG&E and some of the Intervenors filed evidence into the record, the Commission is concerned by the insufficient record in this case regarding the appropriate compensation rate for energy supplied to the grid. The record does not offer quantification from LG&E or from the Intervenors for several compensation rate components that the Commission considers are necessary to adequately compensate NMS-2 customers. As the law clearly requires, following the initiation of this proceeding by LG&E, it is the Commission's obligation to determine the appropriate compensation rate for net metering.[80] Therefore, the Commission finds that the existing record is insufficient to support a conclusion whether the proposed NMS-2 export compensation rate is fair, just and reasonable.

For example, the record is deficient on generation capacity value and additional analysis regarding the existence and value of avoided generation capacity costs from customer-generators is required. LG&E did not provide avoided generation capacity cost in the proposed NMS-2 export compensation rate, arguing that LG&E does not have legally enforceable dispatch rights[81] to renewable distributed generating facilities and, therefore, distributed generation yields no appreciable savings in generation fixed costs.[82] In LG&E's 2018 integrated resource plan (IRP), it indicated a likely need for capacity, potentially as early as 2026.[83] In this proceeding, when discussing how an avoided

[80] KRS 278.466(3).

[81] Direct Testimony of William Seelye (Seelye Direct Testimony) (filed Nov. 25, 2020) at 44.

[82] Seelye Direct Testimony at 55.

[83] Case No. 2018-00348, *Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company* (filed Oct. 19, 2018), IRP Vol. I, p. 5-38.

capacity value could be calculated, LG&E indicated that a significant amount of data and analysis would be needed to make such a calculation.[84] Critically, LG&E did not explain how it could have determined that there is no avoided generation capacity value without a similarly rigorous, data-driven analysis as it has proposed for avoided capacity cost. The Commission notes that the Intervenors did not provide a specific generation capacity value either.

The Commission recently approved a net metering successor rate for Kentucky Power[85] that proposed a methodology for calculating generation capacity value. The approved net metering successor rate in that case quantified the following avoided-cost elements: energy, ancillary services, generation capacity, transmission capacity, distribution capacity, carbon cost, and environmental compliance cost. Additionally, Kentucky Power will file specific information pertaining to a job benefit value in the next net metering case filed by the utility.

In the Kentucky Power case, the Commission articulated its desire for more evidence to take under consideration, including testimony, fact evidence, and analysis:

> [A]n intervening party's failure to provide evidence regarding an issue does not equate to a shifting of the burden of proof, nor is it the case that a utility has met its burden of proof when the utility's evidence is the only evidence in the record. When a utility meets it burden of proof, an intervening party has the opportunity, but not the requirement, to rebut the utility's proof through evidence. When a party does not file certain evidence into a case record, the Commission typically makes note of that in an order to be thorough and avoid the misperception that a party's argument has been omitted. Here, due to the novelty of establishing successor net metering rates, the Commission would have welcomed if the intervening parties

[84] LG&E's Response to Commission Staff's Fourth Request for Information (Staff's Fourth Request) (filed Mar. 12, 2021), Item 4.

[85] Case No. 2020-00174, *Kentucky Power Company* (Ky. PSC May 14, 2021).

> had shared their expertise and experience in quantifying certain evidence, but we emphasize that the intervening parties did not have an affirmative obligation to do so.[86]

We reiterate here that, while the Intervenors do not have the burden of proof on the net metering successor rate, the Commission granted the parties' requests for permissive intervention in this proceeding so that they could present issues and develop facts that assist the Commission in rendering its decision.[87] We encourage the parties that were granted permissive intervention to draw upon their expertise to quantify issues they present and facts they develop to assist the Commission to the greatest degree possible.

Because the record is insufficient to support a finding that the NMS-2 export compensation rate is fair, just and reasonable, the Commission finds that a decision regarding NMS-1 and NMS-2 should be deferred to afford the parties the opportunity to develop a thorough, robust record with sufficient evidence to support a finding that LG&E's proposed Tariff NMS-2 rates are fair, just and reasonable.

The Commission is cognizant that it must issue a decision on this issue on or before September 24, 2021, which is the statutory due date established by KRS 278.190(3), and will timely establish a procedural schedule for investigating NMS-1 and NMS-2. The procedural schedule will consist of supplemental information requests, supplemental testimony, supplemental rebuttal, and a hearing. Parties are advised to submit supplemental testimony related to avoided energy cost,[88] ancillary services cost,

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[86] *Id.* at 22.

[87] *See* 807 KAR 5:001, Section 4(11). The Attorney General is the only party with a statutory right to intervene in matters before the Commission in accordance with KRS 367.150(8).

[88] *See* Case No. 2018-00348, LG&E/KU 2018 IRP, Vol. III, p. 17, Table 9, and p. 21.

generation capacity cost,[89] transmission capacity cost,[90] distribution capacity cost, carbon cost,[91] environmental compliance cost,[92] and, separately, job benefits as they relate to calculating the NMS-2 export compensation rates.

Status of Net Metering Pending Application

LG&E presented contradictory arguments regarding the date and circumstances under which NMS-1 would be closed to new customers. In its testimony and abbreviated public notice, LG&E stated that customers with eligible electric generating facilities who submitted an application for net metering service before the effective date of rates established in this proceeding could take service under NMS-1.[93] However, LG&E's full notice and proposed tariff stated that customers with an eligible electric generating facility could take service under NMS-1 if the customer executed LG&E's written application for Interconnection and Net Metering prior to January 1, 2021.[94] LG&E later clarified that customers whose eligible electric generating facilities are in service prior to Commission approval of NMS-2 may take service under Rider NMS-1; customers whose eligible

[89] *See Id.,* Vol. 1, p. 5-16, Figure 5-11 p. 5-20, and pp. 6-17, 6-18; and Vol. III, p. 7, Figure 3, and p. 21.

[90] *See Id.*, Vol. 1, p. 5-35, Table 5-12, p. 6; and Vol. III, pp. 13-15, 16, and 18.

[91] *See Id.,* Vol. 1, p. 5-19, p. 5-22, p. 5-23, Table 5-5, and p. 5-24, Table 5-6; and Vol. III, p. 15, , Table 8, and p. 16, Figure 9.

[92] *See Id.,* Vol. 1, pp. 8-29 through 8-36; and Vol. III, p.8

[93] Direct Testimony of Robert M. Conroy (Conroy Direct Testimony) at 23, lines 4–11; and Application, Tab 6, Exhibit A, at 2.

[94] Application, Tab 6, Exhibit C, at 29. *See also* Application, Tab 4, P.S.C. No. 20, Original Sheet No. 57.

generating facilities are not in service prior to the date that the Commission approves NMS-2 must take service under NMS-2 regardless of their application date.[95]

Some intervenors argued that customers with net metering applications that were pending prior to the effective date of an Order approving NMS-2 should be eligible to take service under NMS-1 or NMS-2, regardless of whether or not the facility was installed and operating by that date.[96]

The express language of KRS 278.466(6) states that customers with an "eligible electric generating facility in service prior to the effective date of the initial net metering order by the commission" are eligible to take service under the tariff in place when "the eligible customer-generator began taking net metering service."

Based on the plain language of KRS 278.466(6), the Commission finds that the eligible generating facility must be in service prior to the effective date of the Commission's approval of NMS-2 in order for the eligible customer-generator to be eligible to take service under NMS-1. Here, that date is the effective date of the Commission's future Order approving the Rider NMS-1 and Rider NMS-2 compensation rates. However, although the express language of the statute rules in this singular instance, the Commission warns LG&E about their cavalier language regarding serious rate matters. Seemingly, the public-facing information LG&E provided on this subject, including testimony and the public notice, was relatively accommodating to potential net metering customers. For instance, public notices mentioned merely the filing or acceptance of an application for service in order to be provided legacy status.

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[95] LG&E's Response to KYSIA's First Request for Information (filed Jan. 22, 2021), Item 4c.

[96] KYSIA's Post-Hearing Brief (filed May 24, 2021), at 4, 6–8; Joint Intervenors' Post-Hearing Brief (filed May 24, 2021) at 6, 13–16; and Joint Intervenors' Response Brief (filed June 1, 2021) at 15.

Nevertheless, when questioned on the subject LG&E's "clarification" was for customers to read the fine print, necessarily cross-referencing the tariff language with multiple statutes. It is the Commission's experience that in cases of this size, public notices and testimony are the two items the general public are most likely to review, and must accurately represent proposed rates and conditions of service.

Net Metering Service Interconnection Guidelines

LG&E proposed to update its Net Metering Service Interconnection Guidelines (Interconnection Guidelines), stating that interconnected eligible customer generation transforms the distribution system from a one-way delivery mode into a complex two-way network for which electricity flows need to be carefully monitored and balanced and proper system protection applied. LG&E maintained that the new guidelines reflect issues presented by new technology.[97] LG&E also maintained that it will propose the same guidelines in Case No. 2020-00302[98] and, if necessary, update the Interconnection Guidelines based on guidance from the Commission.[99]

KYSIA recommended that the Commission consider substantive changes to the Interconnection Guidelines in Case No. 2020-00302 rather than this proceeding. KYSIA stated that doing so would allow for the Interconnection Guidelines to be standardized and aligned across multiple Kentucky utilities.[100]

[97] Conroy Direct Testimony at 28, lines 3–10.

[98] Case No. 2020-00302, *Investigation of Interconnection and Net Metering Guidelines* (filed Sept. 24, 2020).

[99] Conroy Direct Testimony at 29, lines 1–7.

[100] Direct Testimony of Benjamin D. Inskeep, at 25–26, lines 14–2.

The Joint Intervenors recommended that the Commission reject the proposed revisions to the interconnection guidelines related to net metering as being inconsistent with KRS 278.467(2) and (3), which require each utility's interconnection guidelines to conform to the guidelines developed by the Commission.[101]

Having considered the case record, and being otherwise sufficiently advised, the Commission finds that, because the Interconnection Guidelines are applicable to all jurisdictional electric utilities, they must be standardized and aligned across all jurisdictional electric utilities. Addressing them in a case-by-case, piecemeal fashion is antithetical to developing standardized guidelines. For these reasons, the Commission finds that LG&E's proposed revisions to its Interconnection Guidelines are denied. We further find that LG&E should raise its proposed revisions to the Interconnection Guidelines as issues to be determined in Case No. 2020-00302.

Net Metering Service Application Forms

LG&E proposed to remove its net metering service application forms from its tariff and to file any future changes to the forms with the Commission in the most recent administrative case concerning net metering guidelines. LG&E explained that the forms would still be available on its website and that paper versions would be available upon request. LG&E asserted that removing the forms from the tariff would reduce the size of the tariff and that it would reflect the fact that customers interested in net metering service are able to fill the forms out online.[102]

[101] Joint Intervenors' Post-Hearing Brief at 17.

[102] Conroy Direct Testimony at 28, lines 11–22.

The Commission notes that the application forms are one page each, and thus removing them from the tariff would have no significant effect on the size of the tariff. In addition, whether the forms are in the tariff or not, customers could still complete the forms online if they so choose. The Commission concludes that future revisions to the application forms could receive a more thorough review through revisions to the tariff than through just filing them into the post-case file of an administrative case. For these reasons, the Commission finds that LG&E's proposal to remove the net metering service application forms from its tariff and to file them with the Commission in the most recent administrative case concerning net metering guidelines should be rejected.

Transferring, Closing, or Creating a New Account

LG&E indicated that, in circumstances where both persons in a marriage are listed on an account, if they were to divorce and one spouse stayed in the house or one were to pass away and the surviving spouse stayed in the house, the account would then switch exclusively to the then-determined primary account holder. If the premises were served under NMS-1 or NMS-2, any accumulated bill credits would be maintained under the exclusive then-determined primary account holder's account. However, if only one spouse's name is listed on the account and the couple divorced with the spouse whose name is not on the account staying in the house, or one spouse passed away and the surviving spouse stayed in the house, seemingly due to internal processes, the old account would be closed and a new one created. When a new account is established under these circumstances and the premises continue to be served under NMS-1 or NMS-2, any accumulated credits would not be transferable or eligible for a cash refund on the closing of the account. LG&E indicated they use the same process for all rate schedules when transferring, closing, or creating a new account.[103]

The Commission is concerned about the fairness of LG&E's process for determining when an account should be closed and a new one created. Because this process affects all customers, including those taking service under NMS-1 or NMS-2, the Commission will further investigate this issue during the continuance of this proceeding, and will review the impact of the condition of service on all customers.

MISCELLANEOUS TARIFF ISSUES

Late Payment Charges

Evidence collected in Case No. 2020-00085[104] has challenged the efficiency of late payment charges to certain customers. Therefore, the Commission has recently reviewed utilities' late payment charges during rate cases. In its response to Commission Staff's Second Request for Information in Case No. 2020-00085, LG&E provided data indicating that the on time pay percentage for residential customers remained fairly steady during the months that the required waiver of late payment charges was in place; however, there was a drop off in the months of October, November and December 2020.

The late payment charge is intended to elicit customer behavior; however, LG&E also claims that the charge is cost based. LG&E provided support showing the average cost per residential late payer is $4.56, while the average late payment charge revenue

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[103] LG&E's Response to Staff's Post-Hearing Request, Item 28.

[104] Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19.*

per residential late payer is $4.42.[105] LG&E states that the average cost per residential later payer did not include corporate burdens.[106] To determine the average cost per residential late payer, LG&E included the cost to print and mail the termination notice and the cost of customer contact. The customer contact component was calculated by determining a direct cost per transaction for all calls handled by customer service representatives and the Interactive Voice Response System (IVR); multiplying that cost by the number of calls related to account/billing inquiries and payment arrangements/credit; and dividing the result by the total number of calls related to account/billing inquiries and payment arrangements/credit handled by customer service representatives and IVR.[107]

While the percentage of residential customers paying on time remained steady for most of the period the late payment charge waiver was in place, the evidence does show that there was a fairly significant decrease in the number of residential customers paying on time during the months of October through December 2020. Regarding the cost support provided, the Commission is concerned that LG&E may be overstating the costs, by allocating fixed expenses of the IVR, for instance, and understating the number of contacts related to late payments, particularly by not including any of the 1.2 million customer payment interactions. However, based on the case record, including the Stipulation provisions agreed to by parties who represent the interests of residential customers, the Commission accepts that the 3 percent residential late payment charge is

[105] LG&E's Response to Metropolitan Housing Coalition, Kentuckians for the Commonwealth, and Kentucky Solar Energy Society's Second Request for Information (filed Feb. 19, 2021), Item 2, page 6 of 6.

[106] Attachment to LG&E's Response to Staff's Post-Hearing Request, Item 21.

[107] *Id.*

fairly representative of costs incurred, and thus LG&E may continue charging the 3 percent residential late payment charge. In LG&E's next general rate case, the Commission finds that LG&E should file formal cost support supporting the 3 percent, or another percentage, residential late payment charge.

Residential Time-of-Day Service

Under LG&E's Electric Rate RS – Residential Service, if a customer receives a pledge for or notice of low income energy assistance from an authorized agency, they are not assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor are they assessed or required to pay a late payment charge in any of the 11 months following receipt of such pledge or notice. This is a positive and beneficial offering, and the Commission commends LG&E for having and maintaining such a provision. This term of service ensures that customers who already struggle to pay are not placed in a position where, in addition to being unable to pay for service rendered, they are also required to pay ever-increasing late fees that they likely cannot afford. Not waiving a late fee in this instance creates added hardship, does not serve any purpose in incenting appropriate behavior and only creates additional and unrecoverable bad debt expense that is ultimately recovered from other customers.

In reviewing LG&E's Residential Time-of-Day (RTOD) tariffs, the Commission notes that those rate schedules do not contain that same provision. The Commission sees no reason why such a provision should not also be applied to residential customers taking service under RTOD-Energy or RTOD-Demand, as those rate schedules do not prohibit someone receiving low-income energy assistance from taking service under the rate schedules. Therefore, the Commission finds that the provision regarding the late payment charge included in Electric Rate RS for residential customers receiving a pledge for or notice of low-income energy assistance from an authorized agency should also be added to LG&E's RTOD tariffs.

Late Payment Fee Waiver

LG&E's tariffs currently allow residential customers to request that one late payment fee be waived per year if the customer is in good standing, meaning that they have not been assessed a late payment charge for the previous 11 months. LG&E proposed to extend the waiver provision to non-residential customers, with the exceptions of those served under electric rate schedule Pole and Structure Attachment Charges (PSA) and gas rate schedules Local Gas Delivery Service (LGDS), Pooling Service – Rider TS-2 (PS-TS-2), and Pooling Service – Rate FT (PS-FT). LG&E witness Saunders stated that LG&E prefers to give customers the choice of when they want to have their late payment charge waived, under the belief that doing so creates a positive customer experience.[108] However, as later pointed out by LG&E's witness, Robert M. Conroy, if a customer fails to request that a late payment charge be waived upon the first instance, then that customer would have to wait at least 12 months before they could request a waiver because they would no longer be considered in good standing after being assessed a late payment charge.[109] The waiver provision appears to have been sparsely utilized by LG&E's customers since it went into effect in 2019. LG&E has not been proactively informing customers of the option to have a late payment charge waived.

[108] Hearing Video Transcript (HVT) of the April 26, 2021 Hearing at 15:47:28.

[109] HVT of the April 28, 2021 Hearing at 11:21:50.

Customers only become aware of that option if they make a call to LG&E or review LG&E's tariff.

With over 390,000 residential customers, only 396 customers took advantage of the waiver option between June 2019 and February 2020.[110] That amounts to approximately 0.1 percent of LG&E residential customers. The utilization numbers indicate that customers are either unaware of the option to have a late payment charge waived or they do not understand when they can ask for a waiver of the late payment charge. In its post-hearing brief, LG&E indicated that it will include language regarding the availability of the late payment charge waiver provision in the June 2, 2021 edition of its Powersource newsletter, which is distributed as a bill insert to all residential paper bills and is distributed electronically to customers who receive communications via electronic means. LG&E also stated that they have posted new language to its website regarding the availability of the late payment charge waiver.

The Commission finds that adding the late payment waiver provision to non-residential customers, with the exception of those served under electric rate schedule PSA and gas rate schedules LGDS, PS-TS-2, and PS-FT, is reasonable and that it should be approved as modified below. While the Commission applauds LG&E's improvement in communicating the availability of the late payment charge waiver to its residential customers, because the customer actually does not have a choice of when to request the late payment fee waiver and the fact that no rational customer eligible for such a waiver would choose to not waive a late payment charge if they knew they would not be able to do so for at least another 12 months, the Commission finds that the late payment charge

[110] LG&E's Response to Staff's Post-Hearing, Item 40.

waiver should be automatic for both residential and non-residential customers if a customer is in good standing.

In its Post-Hearing Brief, LG&E asserted that changing the late payment charge mechanism to automatic instead of by request would impact the revenue requirement as reflected in the parties' negotiated stipulation. When calculating the revenue requirement in these proceedings, LG&E indicated that it did not assume any late payment charge waivers and thus did not reduce miscellaneous revenues. It also indicated that they were not seeking regulatory asset treatment for late payment charge waivers that are ultimately granted.[111]

The Commission finds no merit in LG&E's argument that the revenue requirement should be increased if the waiver is made automatic, because all customers who have the option could choose to exercise it each year anyway, making LG&E indifferent between the two paths. Because LG&E had the opportunity to account for late payment charge waivers in its revenue requirements or to request regulatory asset treatment for late payment charge waivers and chose not to do so, the Commission finds that no adjustment should be made to the revenue requirements because of the change of the waiver provision from upon request to automatic.

<u>Resale of Electric/Gas Energy</u>

Both of LG&E's current tariffs include provisions prohibiting customers from reselling electric or gas energy. However, the tariffs expressly allow a customer to allocate one's bill to any other person, firm, or corporation provided the sum of the

[111] Conroy Direct Testimony at 49, lines 18–22.

allocation does not exceed LG&E's billing. In Case No. 2018-00261,[112] Duke Kentucky proposed to add language to its tariff that would have allowed customers to allocate their bills to others as long as such allocations did not exceed Duke Kentucky's billing. Ultimately, the Commission rejected the proposed language finding that it would expressly authorize the allocation of bills by master-metered customers to others without any monitoring of the allocation process by Duke Kentucky. LG&E stated that they do not have the means of monitoring or verifying the accuracy of such allocations without a meter and that there is no metering that LG&E could use to bill directly. LG&E also stated that the administrative cost of monitoring such allocations could be significant.[113]

In Case No. 2020-00375,[114] Duke Kentucky proposed a special contract that would have allowed Skypoint Condominium Owners Association, Inc. (Skypoint) to submeter its facility and allocate the bills to the residents. In that contract, Skypoint agreed that it would not charge its tenants receiving natural gas service any more than the pro-rated amount of Duke Kentucky's total monthly natural gas bill. The Commission approved the Agreement with the condition that Duke Kentucky commit to monitor the Skypoint allocations three times per year, twice during the peak season and once during the summer.

In order to maintain consistency and in order to address its concerns expressed in the two Duke Kentucky matters, the Commission will allow the language regarding

[112] Case No. 2018–00261, *Electronic Application of Duke Energy Kentucky, Inc. for Authority to 1) Adjust Natural Gas Rates 2) Approval of a Decoupling Mechanism 3) Approval of New Tariffs 4) And All Other Required Approvals, Waivers, and Relief* (Ky. PSC Mar. 27, 2019), Order at 16–17.

[113] LG&E's Response to Commission Staff's Third Request for Information, Item 2.

[114] Case No. 2020-00375, *Electronic Tariff Filing of Duke Energy Kentucky, Inc. of a Written Consent of Sub-Metering with Skypoint Condominium Owners Association, Inc.* (Ky. PSC, Feb. 25, 2021)

allocating bills to remain in LG&E's tariffs if LG&E commits to monitoring any such allocation three times per year, twice during the winter and once during the summer. If LG&E will not commit to such monitoring, for the same reason that we denied Duke Kentucky's request, the Commission finds that the language regarding allocation of bills to others is unreasonable and that it should be removed from LG&E's tariffs. Such language expressly authorizes the allocation of bills by master-metered customers to others without any monitoring of the allocation process by LG&E. Absent monitoring of the allocation process, those being allocated such bills would have no assurance that their allocated share of the bill is accurate and does not represent a resale of service at a profit.

<u>Outdoor Sports Lighting</u>

The Commission notes that LG&E's Outdoor Sports Lighting Tariff (Rate OSL) is being utilized sparsely, despite having the largest rate of return per LG&E's cost of service study. Currently, LG&E's Rate OSL is limited to 20 customers, with only 1 customer taking service under it now.[115] Increased participation in Rate OSL could provide a significant benefit to LG&E's other customers. The Commission finds that LG&E should develop a plan to market Rate OSL to potential customers and that it should report on such marketing activities in its next general rate case. LG&E should include in that report the reasons that any potential Rate OSL customer chose another rate schedule over Rate OSL.

<u>Non-Recurring Charges</u>

[115] Seelye Direct Testimony at 33, lines 8–9.

In Case No. 2020-00141,[116] the Commission found that the calculation of non-recurring charges should be revised because only the marginal costs related to the service should be recovered through special non-recurring charges for service provided during normal working hours. In reaching that decision, the Commission found that personnel are paid for work during normal business hours regardless of whether they are on a field visit or not, and therefore labor costs included in non-recurring charges that occur during regular business hours should be eliminated.

As demonstrated by the evidence of record, LG&E relies on employee and contract labor to perform its non-recurring services.[117] In this proceeding, due to a number of factors, which include the use of contract labor, the amount of labor in the charge, the number of instances the charge was assessed during the test year, the charge being directly requested by the customer, or the charge being a result of unauthorized service, the Commission has chosen not to remove labor from the following charges: returned payment charge, meter test charge, meter pulse charge, unauthorized connection charge, gas disconnect/reconnect service charge, inspection charge, charge for temporary or short-term service, and additional trip charge.

Regarding the electric disconnect/reconnect service charge, the disconnect/reconnect service charge will no longer be charged to customers who have AMI meters capable of remote disconnection and reconnection. Due to the phasing out of disconnect/reconnect charges as AMI meters are deployed and LG&E's use of

[116] Case No. 2020-00141, *Electronic Application of Hyden-Leslie County Water District for an Alternative Rate Adjustment* (Ky. PSC Nov. 6, 2020).

[117] LG&E's Response to Commission Staff's Second Request (filed Jan. 22, 2021), Item 123.

employee and contract labor to perform these services, the Commission has chosen not to remove labor from the disconnect/reconnect charge.

Gas Meter Test Fee

LG&E originally proposed a gas meter test fee of $101; however, it later revised the proposed amount to $112.86 to include transportation expense and correct the amount contributed to labor.[118] The Commission finds the revised amount of $112.86 to be reasonable and that it should be approved.

Bill Formats

LG&E corrected the bill format in its proposed tariffs to include a line item for taxes and fees because the customer utilized to generate the original proposed bill format was tax-exempt, causing the taxes and fees line item to not appear.[119] The Commission finds that the revised bill format to be reasonable and that it should be approved.

Cogeneration and Small Power Production Qualifying Facilities

As noted above, the Stipulation did not address LG&E's proposed revisions to its small and large capacity cogeneration and small power production qualifying facilities tariffs (SQF and LQF).

LG&E proposed to revise its SQF tariff to treat holidays that fall on weekdays as a weekday for purposes of determining on-peak periods. LG&E asserted that this would

[118] LG&E's Response to Commission Staff's Third Request for Information (filed Jan. 22, 2021), Item 45, and LG&E's Response to Staff's Post-Hearing Request , Item 22.

[119] Attachment to LG&E's Response to Commission Staff's Sixth Request for Information (filed Apr. 20, 2021), Item 3.

align the application of billing under Tariff SQF with its other time-of-day offerings, which treat holidays as weekdays.[120] No intervenor objected to this revision.

LG&E also proposed to revise the definition of hourly avoided energy cost in its LQF tariff to exclude actual fuel expenses that are fixed and non-avoidable. LG&E maintained that the proposed revision allows LG&E to exclude fuel related costs that are fixed and non-variable in nature, such as, natural gas transportation fees, fixed rail transportation costs, rail car leasing, and barge fleeting.[121] LG&E explained that this list is not meant to be all-inclusive and that it may incur additional fuel related costs that meet the revised definition in the tariff.[122] KYSIA objected to this revision, arguing that the open-endedness of the proposed language would render a QF contract meaningless as LG&E could contract away compensation due to a QF by executing longer-term agreements that it then characterizes as fixed.[123]

KYSIA made recommendations regarding the SQF and LQF tariffs, including: (1) the avoided energy costs under Tariff SQF and Tariff LQF be modified to include hedging value and avoided line losses; (2) the contract term for Tariff SQF be extended to a minimum of ten years; (3) capacity compensation should be established for Rider SQF under the same recommended methodology for Tariff LQF; (4) the Commission reject LG&E's proposed revisions to the methodology for establishing energy rates under Rider

[120] LG&E's Response to Commission Staff's Second Request for Information (filed Jan. 22, 2021), Item 102a.

[121] LG&E's Response to Commission Staff's Second Request for Information, Item 102b and LG&E's Response to Commission Staff's Third Request for Information (filed Feb. 19, 2021), Item 19a.

[122] LG&E's Response to Commission Staff's Third Request for Information, Item 19a.

[123] Direct Testimony of Justin A. Barnes at 13, lines 10–17.

LQF; (5) the current Tariff LQF be modified to state that the current capacity calculation methodology only applies during resource sufficiency as indicated by LG&E's most recent integrated resource plan (IRP) or related proceedings in which LG&E proposes to build or otherwise acquire capacity; (6) avoided capacity cost during periods of resource insufficiency should be established based on the costs of a proxy unit defined by the LG&E's most recent IRP as the next unit addition; and (7) the Commission require LG&E to establish a term of ten years or more for LQF contracts that involve the sale of capacity.[124]

Based upon the case record and being otherwise sufficiently advised, the Commission concludes that the record is insufficient to support a finding that LG&E's proposed revisions to SQF and LQF are fair, just and reasonable. Therefore, the Commission finds that a decision regarding SQF and LQF should be deferred to afford the parties the opportunity to develop a thorough, robust record with sufficient evidence to support a finding that LG&E's proposed SQF and LQF revisions are fair, just and reasonable. The Commission is cognizant that it must issue a decision on this issue on or before September 24, 2021, which is the statutory due date established by KRS 278.190(3), and will timely establish a procedural schedule to investigate this issue.

<u>Legacy Status of General Service and Power Service Customers</u>

[124] KYSIA's Post-Hearing Memorandum Brief (filed May 24, 2021) at 34–35.

In Case No. 2008-00252,[125] LG&E proposed significant changes to some of its rate schedules, eliminating some while adding new rate schedules and revising eligibility criteria for certain rate schedules. To minimize the impact to customers, LG&E permitted customers that did not qualify for service under the new availability terms to become legacy customers under the General Service (Rate GS) and Power Service (Rate PS) rate schedules. In Case No. 2012-00222,[126] LG&E revised the availability provisions of Rate GS and Rate PS to state that legacy customers that elect to take service under another rate schedule for which they qualify could not take service under the rate schedule they had legacy status under again unless and until they met the availability requirements of the rate.

In this proceeding, LG&E proposed to further reduce the number of legacy customers by removing legacy status for legacy customers who meet the availability requirements of their rate schedules on the date the new rates go into effect from this proceeding. LG&E proposed to determine whether the legacy customers meet the availability requirements by examining their usage data for the 12 months ending January 31, 2020. LG&E chose the 12 months ending January 31, 2020, in order to avoid the effects of the Covid-19 pandemic on customers' usage data. This would eliminate legacy status for 247 Rate GS customers and 97 Rate PS customers.[127]

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[125] Case No. 2008-00252, *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates* (Ky. PSC Feb. 5, 2009).

[126] Case No. 2012-00222, *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, a Certificate of Public Convenience and Necessity, Approval of Ownership of Gas Service Lines and Riser, and a Gas Line Surcharge* (Ky. PSC Dec. 20, 2012).

[127] Conroy Direct Testimony at 33–34, lines 12–7.

Removing legacy status for the affected customers would create the possibility of revenue shifting between Rate GS and Rate PS because rates approved in this proceeding are established based upon, among other things, the number of customers in each rate schedule, but during the stay-out period, some of those customers would lose their legacy status and have to change rate classes permanently. This potential for revenue shifting between Rate GS and Rate PS would move the rate classes away from the approved revenue allocation. This would also create frustration and confusion for those customers who lose their legacy status and are forced to switch rate schedules if they fail to meet the eligibility requirements of their current rate schedule in the future. Therefore, the Commission finds that the proposal to remove legacy status from Rate GS and Rate PS legacy customers who meet the eligibility requirements of their current rate schedule is not reasonable and should be rejected.

Warranty Service

LG&E proposed a Warranty Service for Customer-Owned Exterior Electric Facilities Rider (Rider WT) which provides the terms under which LG&E would perform billing and collection services for firms providing warranty service to LG&E's residential customers for the repair or replacement of customer-owned exterior electric facilities serving the customer's residence and connected to LG&E's distribution facilities. Any firms that choose to provide such warranty service to LG&E's residential customers could contract with LG&E for billing and collection services. The contract would establish the specific terms of the service. LG&E will bill the warranty service to those customers that sign up for a warranty service as a separate line item on the customer's bill and would retain a certain percentage of the fee, as agreed upon in the contract. Customer payments would be applied in the following order: (1) amounts owed to LG&E for current billing period; (2) unpaid balance for electric service provided in prior billing periods; and (3) fees, including any warranty service fees or taxes collected for other entities. A customer's service would not be terminated if the customer did not pay the warranty fee.[128]

While the warranty fee would be listed as a separate line item on bills for those customers that signed up for warranty service, the bill would not specifically state that failure to pay the warranty fee would not result in a termination of the customer's electric service. LG&E asserted that the marketing plan will state that electric service will not be shut-off for failure to pay the warranty fee. Customers that do not pay the fee would be removed from the warranty program and notified by the firm providing the warranty service.[129]

The Commission finds Rider WT to be reasonable and that it should be approved subject to the modification that LG&E should add a message to the bills for customers who purchased the warranty service stating that the warranty service is optional, that the warranty company is not the same as LG&E and is not regulated by the Public Service Commission, and that the customer does not have to pay the warranty service fee to continue receiving regulated services from LG&E.

[128] Conroy Direct Testimony at 47–48, lines 15–19.

[129] LG&E's Response to Commission Staff's Second Request for Information (filed Jan. 22, 2021), Item 56.

OTHER

Southeast Energy Exchange Market (SEEM)

LG&E is a member of SEEM, an organization of utilities in the Southeast that are not members of organized wholesale markets or Regional Transmission Operators such as PJM or MISO. SEEM is not an organized market but is a mechanism similar to a bulletin board that will inform participants of available transmission capacity 15 minutes into the future. This will facilitate bilateral trading amongst participants. The SEEM proposal is presently before FERC for approval.

LG&E shall inform the Commission through quarterly filings the status of the FERC proceeding and any changes that are made to the original proposed organization. In these filings, LG&E shall report any matters in other jurisdictions that require other jurisdictions' approval for activity related to the formation of SEEM. This report should indicate any conditions imposed on SEEM participants pursuant to the matters required. The initial report under this requirement shall be filed with the Commission by September 30, 2021 and shall continue until all SEEM-related regulatory approvals for all SEEM utilities are complete. This filing shall be make in the post-case correspondence file in this matter. In addition, LG&E shall file, as part of the off-system sales portion of its monthly Fuel Adjustment Clause filings, updates on SEEM activities. This information shall include administrative and legal expenses associated with the FERC proceeding, the costs of SEEM formation and participation and all costs, and revenues related to purchases and sales if SEEM is approved.

Electric Vehicle Charging Stations

Given the proliferation of electric vehicles (EV), LG&E's interest in owning EV charging equipment and the prolonged stay-out period proposed in the Stipulation, the

Commission finds that LG&E should proactively develop a study regarding the optimal locations for EV charging vis-à-vis LG&E's distribution and transmission systems... This is not a study of the best commercial locations within LG&E's service territory for EV stations, taking into account factors like traffic patterns, amount of time parked or visibility. Rather, this is a study that can only be completed by an incumbent utility, used to identify areas of the distribution and transmission system that, with minimal upgrade costs, can best support EV charging. This study shall determine the best EV charging locations from the perspective of efficient utility planning, and should seek approximately 10-20 EV charging locations that represent LG&E's service territory's "low hanging fruit." This study shall be completed by June 30, 2022. LG&E and KU are approved to defer up to $300,000 on a combined basis for the costs of these studies. The Commission does not expect the expense of this study to exceed that amount, but if necessary, LG&E may seek additional leave to defer added expense resulting from the study. The Commission reserves its right to offset these regulatory assets with the annual payments received from Big Rivers, as the expansion of EV charging throughout LG&E's territory is undoubtedly economic development. Prior to initiating this study, LG&E shall seek an informal conference or meeting-tracking meeting with Commission staff, and shall ensure each party to this case is notified and invited to attend. This meeting will provide LG&E with an opportunity to ask questions of Commission staff regarding the goals of the study or any concerns it may have. This forum will also give an opportunity to LG&E to seek input from other parties to this matter on the substance and conclusions of the study.

The Commission has a two-fold concern regarding LG&E's expansion of EV charging. First, with the utility entering an otherwise economically competitive field of EV charging, it has a knowledge advantage. As mentioned above, no competitor will have near the information the utility has regarding its own electrical systems. This can lead to an unfair competitive advantage. The Commission's second concern on this subject is for retail electric customers' protection. The Commission notes that an investor-owned utility earns its shareholder return on the level of investment in the utility. As such, a utility is economically incentivized to increase that level of investment, in order to maximize shareholder return. As such, ahead of LG&E's additional investment in EV infrastructure, the Commission cautions the utility against making unreasonable, unnecessary or unfair investments on the EV front. The Commission will continue to review LG&E's investments and tariffs on this front to ensure customers are not subsidizing LG&E's foray into a competitive line of business. Nevertheless, the Commission takes LG&E's words at face value, notably those in their brief discussing minimization of costs and participation in competitive endeavors while being the incumbent utility.[130]

Additionally, with its next rate application, LG&E shall clearly indicate in testimony where any EV charging stations that it discussed in this proceeding is or will be located and why each site was chosen. Further, LG&E shall identify any other EV infrastructure it has invested in or EV charging stations for which cost recovery is sought in the test year.

BREC Settlement Fund

LG&E should use the funds it receives from the BREC Settlement to support economic development. This amount should be incremental to amounts not in base rates. LG&E shall file annual reports regarding the use of the funds and quantifying the

[130] LG&E Post-Hearing Brief (filed May 24, 2021) at 24–25.

economic impact (i.e., number of jobs, capital investments resulting from the economic development efforts, etc.).

Merger Study

In Case No. 2017-00415[131] the Commission required LG&E to file an initial report and in Case Nos. 2018-00294 and 2018-00295[132] the Commission required LG&E to file annual updates on the potential for a merger of the sister entities. LG&E filed the initial report on August 8, 2018, and annual updates on March 31, 2020, and March 31, 2021. In each study, LG&E did not recommend proceeding with the legal merger of LG&E and KU, asserting that LG&E and KU operate as an integrated company, that costs would exceed savings, that there were not be net savings to LG&E customers, that regulators whose approval is required, other than the Commission, are unlikely to approve if there are rate increases to cover additional costs from merger, and that name change through merger would require additional transactions requiring regulatory approval and additional costs.[133]

The Commission is not convinced that LG&E conducted an impartial or serious analysis of a potential merger. The study appears to be results oriented, with no affirmative steps taken to obtain more than cursory opinions of potential hurdles to

[131] Case No. 2017-00415, *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 (*Ky. PSC Apr. 4, 2018).

[132] Case No. 2018-00294, *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates* (Ky. PSC Apr. 30, 2019); and Case No. 2018-00295, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates* (Ky. PSC Apr. 30, 2019).

[133] Case No. 2017-00415, LG&E/KU Merger Study (filed Aug. 8, 2018); Case No. 2018-00294, LG&E/KU 2020 Merger Study Update (filed Mar. 31, 2020), and LG&E/KU 2021 Merger Study Update (filed Mar. 31, 2021); Case No. 2018-00295, LG&E/KU 2020 Merger Study Update (filed Mar. 31, 2020), and LG&E/KU 2021 Merger Study Update (filed Mar. 31, 2021).

merger. For example, LG&E does not include an analysis of the duplication of costs to ratepayers and stress on regulators' resources from filing what is effectively two distinct rate cases every few years, although it did include the entirety of the costs of one-time rate cases it believed would be necessary to effectuate a merger to "harmonize" rates and the one-time costs of regulatory approval for the merger. LG&E's study is indifferent to the impact its legal status has on others, and it ignores the numerous savings its legal merger would create, both to LG&E's customers and stakeholders.

Finally, on the issue of legal mergers, over the years LG&E often speaks of the importance of branding as a barrier to merger. The Commission notes that LG&E have successfully rebranded after recent acquisitions, first by E.ON U.S. and then by PPL Corporation. These rebranding efforts have been widespread, and likely at a significant cost. The Commission reminds LG&E that it is a government-granted monopoly with the exclusive right to furnish electric service within a certified territory. Its status as a monopoly negates any argument that branding plays any role in preventing a merger.

The Commission expects future merger studies to reflect an unbiased review of the benefits and costs of a legal merger, and we further expect LG&E to address those qualitative risks continually identified as a hurdle to legal merger. Failure on LG&E's part to perform unbiased reviews of the subject may lead to the Commission using other resources to study the subject on the Commission's behalf, without LG&E's involvement.

DSM

In Case No. 2017-00441,[134] LG&E noted that increased customer adoption of energy efficient (EE) measures and declining avoided costs of energy and capacity was occurring, making it more difficult for DSM/EE programs to be more cost-effective.[135] At that time, LG&E had a capacity surplus of approximately 100 MW resulting in an avoided capacity cost of zero. This zero avoided capacity cost was then used as an input for the California tests and resulted in benefit/cost ratios of less than one, indicating that the costs of the programs outweighed the benefits.[136] As a result, LG&E proposed and was granted approval for a substantial reduction in the DSM/EE program. LG&E currently avers that the landscape has changed regarding avoided capacity especially due to the planned retirements of Mill Creek 1, Mill Creek 2, and Brown 3 and additional capacity will be required by 2028.[137] With these capacity needs, the avoided capacity cost will no longer be zero, which will impact the California test results. Therefore, the Commission will require LG&E to begin evaluating possible DSM programs that will add low-cost value and assist in avoiding the high cost of building new generation.

Tax Credits for Carbon Capture

The federal government, through Section 45Q of the IRS Code, provides tax incentives for qualified carbon capture, storage and utilization projects. With a fleet of almost exclusively fossil-fueled generation, LG&E faces uncertainty with regard to the life

[134] Case No. 2017-00441, *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* (Ky. PSC Oct. 5, 2018).

[135] *Id.* at 4.

[136] *Id.* at 29.

[137] HVT of April 28, 2021 Hearing at 2:47:53. HVT of April 27, 2021 Hearing at 1:16:52.

expectancy of these units because of the high probability of carbon dioxide and other greenhouse gas limitations. Any decrease in the useful life of these facilities comes with a risk to the ratepayers in the form of higher rates. This is especially true of Trimble County Unit 2, which went into service in 2011. The remaining book value of that unit is significant, as is the remaining book value of units that have had extensive environmental upgrades, much of which has occurred within the last 15 years.

Based on the Commission's concern, we find that LG&E shall conduct an analysis of the future of LG&E and KU's fossil-fuel generation with particular attention to avenues to reduce undepreciated assets and to protect ratepayers. This shall include an analysis of the 45Q tax incentives and any other approved incentives regarding carbon capture, storage and utilization. This analysis shall be provided in a report to the Commission by November 30, 2021, and should be subsequently updated and provided as part of LG&E's subsequent Integrated Resource Plans, until further notice.

Waiver of Liability in Tariff

The Commission is concerned about the number of provisions in LG&E's various tariffs limiting LG&E's liability. The Commission is also concerned that the language used in some of these provisions is overbroad. Therefore, the Commission intends to establish a separate proceeding in which to investigate the reasonableness of the limitations on LG&E's liability contained in the terms and conditions found in its tariff provisions.

In-Line Inspection

In-Line Inspection (ILI) tools help with support for compliance with U.S. Department of Transportation Pipeline Hazardous Materials Safety Administration (PHMSA) regulations relating to natural gas intra-state transmission pipelines. The Commission is concerned that LG&E maintains a preference for ILI tools and their associated investments as a default, and does not evaluate other options that may be more cost efficient, which then results in either additional expenses or budgetary tradeoffs from other needs. LG&E stated that it has determined it is reasonable and appropriate to in-line inspect every pipeline which it in-line inspects and, except for one transmission pipeline, that there are reasons other than a section containing a high consequence area that warrant ILI.[138] The Commission notes that there is no CFR 192 requirement to use ILI. We also note that LG&E provided no cost analysis to support its response to provide the Commission with the comparative cost for any method considered.[139] Given that ILI is the most expensive inspection technique available, LG&E must apply a judicious consideration of the reasonableness of comparable costs as part of its analysis of the appropriate inspection methods to be used in various circumstances.

Gas Line Tracker

In its application, LG&E proposed to remove the Steel Customer Service Lines and Targeted Removal of County Loops and Steel Curbed Services (Steel Services Program) and the Transmission Modernization Program from its Gas Line Tracker (GLT) and recover associated costs through base rates. LG&E maintained the reasoning is because the Steel Services Program expires at the end of the test year and the Transmission Modernization Program is expected to be completed at the end of the test year.[140] In addition, LG&E removed the Main Replacements portion of the Leak Mitigation Project

[138] LG&E's Response to Staff's Post-Hearing Data Request, Item 2.

[139] *See* LG&E's Response to Staff's Post-Hearing Request, Item 4.

[140] Application at 21, paragraph 39.

and the Aldyl-A Mains and Services Replacement project from the GLT rate base due to their completion. With the removal of the Transmission Modernization Program, LG&E proposed to eliminate the corresponding volumetric charge and only apply a fixed meter rate.

LG&E files an application updating its GLT rates February each year and stated that it will make a GLT rate reconciliation or tariff filing as needed following the conclusion of its base rate case. The most recent update, Case No. 2021-00091,[141] was issued June 28, 2021. LG&E shall file a rate reconciliation through the electronic tariff filing system for any over or under recovery realized through the volumetric charge on or before August 1, 2021. LG&E shall also file testimony in its next base rate case justifying the continuation of the GLT especially given that the primary purposes of the rider have been addressed and completed.

<u>CPCN for Bullitt County Natural Gas Pipeline</u>

In Case No. 2016-00371,[142] the Commission granted LG&E a CPCN to construct a natural gas pipeline located in Bullitt County, Kentucky. The pipeline, as presented in LG&E's application, was approximately 10–12 miles long, intended to improve reliability and serve growth in Bullitt County.[143] LG&E planned to begin the project in 2017, with a targeted completion date in 2019, at an estimated cost of $27.6 million.

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[141] Case No. 2021-00091, *Electronic Application of Louisville Gas and Electric Company for Approval of Revised Gas Line Tracker Rates Effective for services Rendered on and After May 1, 2021* (filed Mar. 1, 2021).

[142] Case No. 2016-00371, *Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates and for Certificates of Public Convenience and Necessity* (Ky. PSC June 22, 2017).

[143] *Id.* at 31.

However, for a variety of reasons including litigation over easements sought by LG&E, the project has been delayed. Of special concern to the Commission is the threefold cost increase. The current estimate to complete the project is $74 million.[144]

The Commission concurs with LG&E's statement that Commission approval of a CPCN is not a finding that the utility can recover the construction costs in rates, but instead is a finding that the project satisfied the legal standard of KRS 278.020 at the time the application was filed with the Commission. The Commission cautions LG&E that if the Bullitt County Pipeline is constructed, any request for recovery of costs through rates will be subject to close scrutiny given the significant increase in cost.

IT IS THEREFORE ORDERED that:

1. The rates and charges proposed by LG&E are denied.

2. LG&E's motion for leave to file the Stipulation and the testimonies in support of the Stipulation is granted.

3. The Stipulation (without exhibits), attached hereto as Appendix A, is approved with the modifications discussed herein.

4. The rates and charges in Appendix B, attached hereto, are fair, just and reasonable for LG&E to charge for service rendered on and after July 1, 2021.

5. Within 20 days of the date of this Order, LG&E shall file notice whether FERC approval of the accounting treatment of AFUDC for AMI deployment is required, and if FERC approval is required, provide the expected timeline for LG&E to file its requires for FERC approval.

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[144] LG&E's Response to Staff's Post-Hearing Request, Item 9.

6. Beginning September 30, 2021, and continuing through the deployment of AMI as set forth in the application, LG&E shall file quarterly reports updating the status of the implementation and deployment of the AMI project, adherence to budgets, adherence to timeliness, any significant change orders, number of AMI implemented, and the number of non-AMI meters removed and retired.

7. LG&E shall file with its next base rate case a written baseline quantifying all benefits derived from AMI deployment in conformance with the items set forth in Appendix F.

8. Beginning on June 30, 2022, and continuing annually thereafter, LG&E shall file with the Commission the detailed plans that set forth, for each item listed in Appendix F, how LG&E will achieve the benefits, and how it will periodically determine whether it is maximizing those benefits. Those periodic reviews shall include a determination of the success and failures for each item for each reporting period and shall clearly indicate what progress LG&E is making to maximize those benefits.

9. LG&E shall develop and file with its next base rate case a prepay program and DSM programs, including those that target low-income customers.

10. LG&E shall develop and file on or before its next base rate case an EV tariff for home and business charging that is cost-based and incents off-peak EV charging.

11. LG&E shall file by June 30, 2022, and continuing annually, a detailed plan for customer engagement of its AMI systems before, during and after AMI deployment, and including through the system's end of useful life.

12. LG&E shall develop and file with its next base rate case detailed plans on AMI obsolescence and replacement strategies that identify, at a minimum, risks and

solutions to early obsolescence, opportunities for greater cross-system compatibility, and successor technologies, including hardware and software, in order to extend the life of as many portions of the proposed AMI systems as reasonably practical.

13. LG&E shall file by June 30, 2022, and continuing annually, detailed plans regarding how LG&E identifies outages, how the AMI systems will facilitate notification and communication of information with customers regarding outages, the estimated times of repair, and the AMI systems' interaction with LG&E's other smart grid investments, including an outage management system.

14. On or before June 30, 2023, LG&E shall file notice that it obtained certification of its Green Button Connect My Data for residential and non-residential customers.

15. LG&E shall file with its next base rate case a detailed plan for reducing the frequency and amounts of its tariffed non-recurring charges resulting from it proposed AMI systems.

16. LG&E shall file in its next IRP, and continuing with each subsequent IRP, a detailed explanation of how LG&E uses the information created by the AMI systems to create additional data or study the remainder of the utility's system. The explanation shall include LG&E's analysis of how the information created by the AMI systems can be used to benefit voltage regulation; power quality; asset management; distribution system investment and utilization; load forecasting, at the circuit level and more granular; peak reduction of generation, transmission and distribution peaks, both coincident and non-coincident; transmission investment and utilization; and the calculation of all avoided cost categories used in determining NMS-2 and QF compensation.

17. LG&E shall file in its next base rate case any other intended uses of data created by its proposed AMI systems not otherwise addressed in ordering paragraphs 15 and 16.

18. LG&E shall file by September 30, 2021, and continuing quarterly, a report that sets forth the status of the SEEM formation proposal currently pending at FERC, including an changes to the original proposed organization proposed or approved by FERC; any matters in other jurisdictions that require other jurisdictions' approval for activity related to the formation of SEEM; and any conditions imposed on SEEM participants by FERC or other jurisdictions.

19. LG&E shall file, as part of the off-system sales portion of its monthly Fuel Adjustment Clause filings, updates on SEEM activities, including but not limited to administrative and legal expenses associated with the FERC proceeding, the costs of SEEM formation and participation and all costs, and revenues related to purchases and sales if SEEM is approved.

20. LG&E shall establish and file by June 30, 2022, a report of a study regarding the optimal locations for EV charging stations in relation to LG&E's distribution and transmission systems using the criteria set forth in this Order to determine the optimal EV charging locations from the perspective of efficient utility planning.

21. LG&E and KU are authorized to establish a regulatory asset for EV charging station location study costs and shall defer up to $300,000 on a combined basis for the costs of the EV charging station location study. If LG&E and KU's combined costs for the study exceed $300,000, LG&E may seek additional leave to defer added expense resulting from the study.

22. The Commission reserves the right to offset EV charging station location study costs regulatory asset with the annual payments received from BREC.

23. Prior to initiating the EV charging station location study, LG&E shall request an informal conference or meeting-tracking meeting with Commission Staff to discuss the goals of the study and any concerns that LG&E may have. LG&E shall provide notice to and an invitation for each party to this case to attend the informal conference or meeting-tracking meeting.

24. LG&E shall file in its next base rate case testimony that clearly indicates where any EV charging stations that LG&E referenced in this proceeding is or will be located and why each site was chosen.

25. LG&E shall clearly indicate in its next base rate case all EV infrastructure that LG&E invested in and EV charging stations for which cost recovery is sought in the test year of LG&E's next base rate case.

26. Beginning June 30, 2022, and continuing annually, LG&E shall file a report that sets forth how BREC Settlement funds are used and quantifying the economic impact, including by not limited to the number of jobs created and capital investments that result from the economic development efforts funded by the BREC Settlement.

27. LG&E shall file by November 30, 2021, a report of LG&E's analysis of the future of LG&E and KU's fossil-fuel generation, including but not limited to an analysis of avenues to reduce undepreciated assets to protect ratepayers; 45Q tax incentives; and any other government-approved incentives regarding carbon capture, storage and utilization.

28. On or before August 1, 2021, LG&E shall file a rate reconciliation for GLT rates through the electronic tariff filing system for any over- or under-recovery realized through the volumetric charge

29. LG&E shall file testimony in its next base rate case justifying the continuation of the GLT.

30. The Commission shall defer decisions regarding Tariffs NMS-1, NMS-2, SQF, and LQF, and shall keep this case open to allow the parties to present additional evidence that LG&E's proposed Tariffs NMS-2, SQF, and LQF are fair, just and reasonable.

31. An eligible generating facility must be in service prior to the effective date of the Commission's approval of Rider NMS-2 in order for the eligible customer-generator to take service under Rider NMS-1.

32. LG&E's proposed revisions to the Interconnection Guidelines are denied. LG&E shall file its proposed revisions to the Interconnection Guidelines as issues to be considered in Case No. 2020-00302.

33. LG&E's proposal to remove the net metering service application forms from its tariff and to file them with the Commission in the most recent administrative case concerning net metering guidelines is denied.

34. LG&E shall file with its next base rate case formal cost support for the 3 percent, or another percentage, residential late payment charge.

35. LG&E shall add to its RTOD rate schedules the provision regarding the late payment charge for residential customers receiving a pledge for or notice of low-income energy assistance from an authorized agency.

36. LG&E's proposal to add the late payment charge waiver provision to its non-residential rate schedules, with the exception of electric rate schedule PSA and gas rate schedules LGDS, PS-TS-2, and PS-FT, is approved as modified in this Order.

37. LG&E shall revise its late payment charge waiver provision to allow for the automatic waiver of the charge for eligible customers.

38. Within 20 days of the date of entry of this Order, LG&E shall file a written statement as to whether it will agree to monitor allocations of bills three times per year, twice during the winter season and once during the summer season. If LG&E will not commit to this condition, LG&E shall remove from both its tariffs the language regarding allocation of bills to others in the Resale of Electric Energy and Resale of Gas Energy sections of its tariff.

39. LG&E shall develop and file in its next base rate case a report of LG&E's plan to market Rate OSL to potential customers including but not limited to marketing activities planned or taken, and the reasons that any potential Rate OSL customer chose another rate schedule over Rate OSL.

40. LG&E's Gas Meter Test fee, as revised, is approved.

41. LG&E's revised bill formats are approved.

42. LG&E's proposal to remove legacy status from certain customers served under Rate GS and Rate PS is denied.

43. LG&E's proposed Rider WT is approved with the condition that for those customers that do sign up for warranty service, LG&E shall add a message to the billing form of those customers stating that the warranty service is optional, that the warranty company is not the same as LG&E and is not regulated by the Public Service

Commission, and that the customer does not have to pay the warranty service fee to continue receiving regulated services from LG&E.

44. LG&E shall not file a LOLP cost of service study in future rate case filings, and shall file a NARUC-approved cost of service study.

45. LG&E shall develop and in its next base rate case file testimony regarding a website that provides transparent real-time utilization data for electric vehicle charging stations that is available to the public.

46. LG&E shall develop and in its next base rate case file testimony regarding a website for third-party providers that identifies electric vehicle charging locations available to third-party providers.

47. Any document filed pursuant to ordering paragraphs 6, 8, 11, 13, 14, 18, 20, 26, 27, and 38 shall be filed in this proceeding's post-case correspondence file.

48. Within 20 days of the date of this Order, LG&E shall file with the Commission, using the Commission's electronic Tariff Filing System, its revised tariffs as set forth in this Order reflecting that they were approved pursuant to this Order.

49. This case shall remain open pending a final determination regarding NMS-1, NMS-2, SQF, and LQF tariffs.

By the Commission

ENTERED

JUN 30 2021 rcs

KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00350 DATED JUN 30 2021

THIRTY PAGES TO FOLLOW

<u>STIPULATION AND RECOMMENDATION</u>

This Stipulation and Recommendation ("Stipulation") is entered into this 19th day of April 2021 by and among Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "the Utilities"); 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 Co. ("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"). (Collectively, the Utilities, AG, DoD, KFTC, KIUC, KYSES, KYSEIA, Kroger, LFUCG, Louisville Metro, MA, MHC, Sierra Club, and Walmart are the "Parties.")

W I T N E S S E T H:

WHEREAS, on November 25, 2020, KU filed with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust 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, <u>*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*</u> ("KU's Application"), and the Commission has established Case No. 2020-00349 to review KU's Application, in which KU requested a revenue increase of $170.1 million;

WHEREAS, on November 25, 2020, LG&E filed with the Commission its Application for Authority to Adjust 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, *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* ("LG&E's Application") (collectively, KU's Application and LG&E's Application are the "Applications"), and the Commission has established Case No. 2020-00350 to review LG&E's Application, in which LG&E requested a revenue increase for its electric operations of $131.1 million and a revenue increase of $30.0 million for its gas operations (Case Nos. 2020-00349 and 2020-00350 are the "Rate Proceedings");

WHEREAS, the AG, DoD, KFTC, KIUC, KYSES, KYSEIA, Kroger, LFUCG, MA, Sierra Club, and Walmart have participated as full intervenors in Case No. 2020-00349;

WHEREAS, the AG, DoD, KFTC, KIUC, KYSES, KYSEIA, Kroger, Louisville Metro, MHC, Sierra Club, and Walmart have participated as full intervenors in Case No. 2020-00350;

WHEREAS, a remote and in person prehearing informal conference for the purpose of discussing settlement and the text of this Stipulation, attended by representatives of the Parties and the Commission Staff, took place on April 15 and 16, 2021, during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in the Rate Proceedings;

WHEREAS, the Parties hereto unanimously desire to settle all the issues pending before the Commission in the Rate Proceedings except as explicitly noted in Section 5.8 herein;

WHEREAS, it is understood by all Parties hereto that this Stipulation is subject to the approval of the Commission, insofar as it constitutes an agreement by the Parties for settlement, and, absent express agreement stated herein, does not represent agreement on any specific claim, methodology, or theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms, or conditions;

WHEREAS, the Parties have spent many hours over several days to reach the stipulations and agreements which form the basis of this Stipulation;

WHEREAS, all of the Parties, who represent diverse interests and divergent viewpoints, agree that, though certain issues have been reserved for litigation at hearing as set out in Section 5.8, this Stipulation, viewed in its entirety, is a fair, just, and reasonable resolution of their issues resolved in this Stipulation; and

WHEREAS, the Parties believe sufficient and adequate data and information in the record of these proceedings support this Stipulation, and further believe the Commission should approve it without modifications or conditions;

NOW, THEREFORE, for and in consideration of the promises and conditions set forth herein, the Parties hereby stipulate and agree as follows:

ARTICLE I. STAY-OUT COMMITMENT

1.1. Four-Year Stay-Out Commitment. The Utilities commit to a base-rate "stay out" until July 1, 2025, such that any changes from base rates approved in Case Nos. 2020-00349 and 2020-00350 shall not take effect before that date. Therefore, the Utilities may file base-rate applications during 2024, but the proposed base rates shall not take effect before July 1, 2025.

1.2. Stay-Out Exceptions.

(A) Each of LG&E and KU will retain the independent right to seek the approval from the Commission of the deferral of: (1) extraordinary, nonrecurring expenses that could not have been reasonably anticipated or included in the Utilities' planning; (2) expenses resulting from statutory or administrative directives that could not have been reasonably anticipated or included in the Utilities' planning; (3) expenses in relation to government or industry-sponsored initiatives; or (4) extraordinary or nonrecurring expenses that, over time, will result in savings that fully offset the costs.

(B) The Utilities will retain the right to seek emergency rate relief under KRS 278.190(2) to avoid a material impairment or damage to their credit or operations.

(C) The provisions of Section 1.1 shall not apply, directly or indirectly, to the operation of any of the Utilities' cost-recovery surcharge mechanisms and riders at any time during the term of Section 1.1, including any base-rate roll-ins, which are part of the normal operation of such mechanisms.

(D) If a statutory or regulatory change, including but not limited to federal tax reform, affects KU's or LG&E's cost recovery, KU or LG&E may take any action either or both deem necessary in their sole discretion, including, but not limited to, seeking rate relief from the Commission.

ARTICLE II. ELECTRIC REVENUE REQUIREMENTS

2.1. Stipulated Items Used to Adjust Utilities' Electric Revenue Requirements. The Parties stipulate the following adjustments to the annual electric revenue used to determine the base rate increase. For purposes of determining fair, just and reasonable electric rates for LG&E

and KU in the Rate Proceedings the parties stipulate the adjustments below. The overall base rate electric revenue requirement increases resulting from the stipulated adjustments are:

LG&E Electric Operations: $77,300,000; and

KU Operations: $115,900,000.

The Parties stipulate that increases in annual revenues for LG&E electric operations and for KU operations should be effective for service rendered on and after July 1, 2021.

2.2. Items Reflected in Stipulated Electric Revenue Requirement Increases. The Parties agree that the stipulated electric revenue requirement increases described in Section 2.1 were calculated by beginning with the Utilities' electric revenue requirement increases as presented and supported by the Utilities in their Applications ($170.1 million for KU; $131.1 million for LG&E electric) as subsequently adjusted by the Utilities' update filings (reducing the requested revenue increases by $0.2 million for KU and $2.7 million for LG&E) and adjusting them as described in Section 2.2. The Parties ask and recommend the Commission accept these adjustments as reasonable without modification, except for those adjustments, if any, resulting from items included in Section 5.3:

(A) **Return on Equity.** The Parties stipulate a return on equity of 9.55% for the Utilities' electric operations, and the stipulated revenue requirement increases provided above for the Utilities' electric operations reflect that return on equity as applied to the Utilities' capitalizations and capital structures underlying their originally proposed electric revenue requirement increases as subsequently adjusted by the Utilities' update filings and the capitalization effects of the adjustment in Section 2.2 (B). Use of a 9.55% return on equity reduces the Utilities' proposed electric revenue requirement increases by $16.7 million for KU and $11.0 million for LG&E. The Parties agree that, effective as of the first expense month after the

Commission approves this Stipulation, the return on equity that shall apply to the Utilities' recovery under their environmental cost recovery mechanism is 9.35% for all environmental compliance plans.

(B) **Depreciation Rates.** Rather than use the depreciation rates the Utilities proposed in their Applications for Mill Creek 1 and 2 and Brown 3 generation units, the Utilities will continue to use their currently approved depreciation rates for ratemaking purposes unless and until changed in later Commission proceedings. The other proposed depreciation rates as filed in the Utilities' applications shall be approved for ratemaking purposes. This adjustment, which includes the associated impact of all depreciation adjustments on the Utilities' capitalization and the amortization of excess accumulated deferred income taxes, reduces the Utilities' proposed electric revenue requirement increases by $33.0 million for KU and $36.5 million for LG&E. A complete set of agreed depreciation rates for the Utilities is attached as Stipulation Exhibit 1.

(C) **Updated Pension and Other Post-Employment Benefits ("OPEB") Expense.** The Parties agree that the Utilities will use the updated 2021 pension and OPEB projections as the new test year estimate for purposes of calculating the revenue requirement. The adjustment to update the pension and OPEB expense amounts will reduce the Utilities' proposed electric revenue requirement increases by $3.9 million for KU and $3.0 million for LG&E.

(D) **Update Long-Term Debt Rate to Reflect Lower Coupon Rates for New Long-Term Debt in Forecasted Test Year.** The Parties agree that the coupon rate for new long-term debt included in the Utilities' forecasted test year should be reduced from 3.70% to 3.40%. This adjustment reduces the Utilities' proposed electric revenue requirement increases by $0.4 million for KU and $0.6 million for LG&E.

2.3. Summary Calculation of Electric Revenue Requirement Increases. The table below shows the calculation of the stipulated electric revenue requirement increases as adjusted from the revenue requirement increases requested in the Utilities' Applications:

Item	KU ($M)	LG&E Electric ($M)
Filed electric revenue requirement increases as adjusted[1]	169.9	128.4
9.55% return on equity	(16.7)	(11.0)
Continue to use current depreciation rates for MC 1 and 2 and Brown 3	(33.0)	(36.5)
Updated pension and OPEB expense	(3.9)	(3.0)
Updated long-term debt rate	(0.4)	(0.6)
Electric revenue requirement increases after stipulated adjustments	115.9	77.3

ARTICLE III. <u>GAS REVENUE REQUIREMENT</u>

3.1. Stipulated Items Used to Adjust LG&E's Gas Revenue Requirement. The Parties stipulate the following adjustments to the annual gas revenue requirement used to determine the base rate increase. For purposes of determining fair, just, and reasonable gas rates the Parties stipulate the adjustments below. Effective for service rendered on and after July 1, 2021, the stipulated adjustments result in an increase in annual base rate revenues for LG&E gas operations of $24,200,000.

[1] *See* KU's and LG&E's Updated Responses to PSC 1-56 dated Feb. 26, 2021; KU Schedule M-2.1; LG&E Schedule M-2.1-E. The "Filed electric revenue requirement increases as adjusted" values shown in the table result from subtracting the updated revenue requirement increase differences shown in KU's and LG&E's Updated Responses to PSC 1-56 from the unadjusted total revenue requirement increases shown in KU Schedule M-2.1 and LG&E Schedule M-2.1-E.

3.2. Items Reflected in Stipulated Gas Revenue Requirement Increase. The Parties agree that the stipulated gas revenue requirement increase described in Section 3.1 was calculated by beginning with LG&E's gas revenue requirement increase as presented and supported by LG&E in its Application ($30.0 million) as subsequently adjusted by LG&E's update filing (increasing the requested revenue requirement by $3.0 million) and adjusting the proposed gas revenue requirement increase as described in this Section 3.2. The Parties ask and recommend that the Commission accept these adjustments as reasonable without modification, except for those adjustments, if any, resulting from items included in Section 5.3.

(A) **Return on Equity.** The Parties stipulate to a return on equity of 9.55% for LG&E's gas operations, and the stipulated revenue requirement increase for LG&E's gas operations reflects that return on equity as applied to LG&E's gas capitalization and capital structure underlying its originally proposed gas revenue requirement increase. Use of a 9.55% return on equity reduces LG&E's proposed gas revenue requirement increase by $3.4 million. The Parties agree that, effective as of the first expense month after the Commission approves this Stipulation, the return on equity that shall apply to the Utilities' recovery under their gas line tracker (GLT) mechanism is 9.35% for all capital expenditures recovered therein.

(B) **Updated Pension Expense.** The Parties agree that LG&E will use the updated 2021 pension and OPEB projections as the new test year estimate for purposes of calculating the revenue requirement. The adjustment to update the pension and OPEB expense amounts will reduce LG&E's proposed gas revenue requirement increase by $1.0 million.

(C) **Update Long-Term Debt Rate to Reflect Lower Coupon Rates for New Long-Term Debt in Forecasted Test Year.** The Parties agree that the coupon rate for new long-term debt included in the Utilities' forecasted test year should be reduced from 3.70% to 3.40%.

This adjustment reduces the proposed revenue requirement increase for LG&E's gas operations by $0.2 million.

(D) **Inline Inspection Normalization Adjustment.** The Parties agree that inline inspection expenses included in the forecasted test year for LG&E's gas operations should be reduced to a 2021-2025 normalized level. This adjustment reduces the proposed revenue requirement increase for LG&E's gas operations by $4.2 million.

3.3. Summary Calculation of Gas Revenue Requirement Increase. The table below shows the calculation of the stipulated gas revenue requirement increase as adjusted from the revenue requirement increase requested in LG&E's Application:

Item	LG&E Gas ($M)
Filed gas revenue requirement increase as adjusted[2]	33.0
9.55% return on equity	(3.4)
Updated pension expense	(1.0)
Updated long-term debt rate	(0.2)
Gas inline inspection expense normalization	(4.2)
Gas revenue requirement increase after stipulated adjustments	24.2

ARTICLE IV. REVENUE ALLOCATION AND RATE DESIGN

4.1. Revenue Allocation and Rate Design. The Parties hereto agree that the allocations of the increases in annual revenues and the rate design for KU and LG&E electric operations, as well as the allocation of the increase in annual revenue and the rate design for LG&E

[2] *See* LG&E's Updated Response to PSC 1-56 dated Feb. 26, 2021; LG&E Schedule M-2.1-G. The value shown in the table results from subtracting the updated revenue requirement increase difference shown in LG&E's Updated Response to PSC 1-56 from the unadjusted total revenue requirement increase shown in LG&E Schedule M-2.1-G.

gas operations, as set forth on the schedules designated Stipulation Exhibit 2 (KU), Stipulation Exhibit 3 (LG&E electric), and Stipulation Exhibit 4 (LG&E gas) attached hereto, are fair, just, and reasonable.

4.2. Tariff Sheets. The Parties hereto recommend to the Commission that, effective July 1, 2021, the Utilities shall implement the electric and gas rates set forth on the tariff sheets in Stipulation Exhibit 5 (KU), Stipulation Exhibit 6 (LG&E electric), and Stipulation Exhibit 7 (LG&E gas) attached hereto, excepting only the issues to be addressed at hearing set out in Section 5.8 below.

4.3. Residential Basic Service Charges to Remain at Current Levels. The Parties agree that the current Basic Service Charges approved by the Commission in Case Nos. 2018-00294 and 2018-00295 for residential gas and electric service shall remain unchanged.

ARTICLE V. TREATMENT OF CERTAIN SPECIFIC ISSUES

5.1. Scheduled Plant Outage Expense Adjustment. The Parties agree to use the Utilities' normalized level of plant outage expenses as filed effective with the change in base rates on July 1, 2021. Effective July 1, 2021, the Utilities 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.

5.2. Advanced Metering Infrastructure ("AMI") Ratemaking. The Parties agree to the following ratemaking-related items regarding the Utilities' proposed AMI deployment:

(A) The Utilities will record their investment in the AMI project as Construction Work In Progress ("CWIP") and accrue an allowance for funds used during construction ("AFUDC") during the implementation period, currently projected to be approximately 5 years.

(B) The Utilities will record a regulatory liability until their first base rate proceedings following AMI implementation or other proceedings to address the AMI revenue requirement following AMI implementation to the extent their actual meter reading and field service expenses are less than the forecast test period level embedded into base rates during these current proceedings. The Utilities also will include in this regulatory liability, until their first base rate proceedings following AMI implementation or other proceedings to address the AMI revenue requirement following AMI implementation, the cost of capital effect during the implementation period for the reduction in net book value and increase in accumulated deferred income taxes for meters replaced and retired during the AMI implementation. The Utilities commit to keep detailed records to document the savings created by AMI that will be recorded in the regulatory liability.

(C) The Utilities will record a regulatory asset during the AMI implementation period comprising three components: (1) operating expenses associated with the project implementation; (2) the remaining net book value of electric meters replaced and retired as part of this project less any excess depreciation recovered in base revenues after the electric meters are replaced and retired; and (3) the difference between AFUDC accrued at the Utilities' weighted average cost of capital and that calculated using the methodology approved by the Federal Energy Regulatory Commission.

(D) For tax purposes, depreciation will begin as the AMI meters, network and systems are put into service at interim dates during the implementation period. Book depreciation expense will be recorded when the entire project is placed in service for the benefit of customers.

(E) The Utilities will seek AMI cost recovery in the first base rate case proceedings following AMI implementation if necessary; otherwise, if no base rate adjustment is required, the Utilities will make a separate filing to address the AMI revenue requirement impact and set the amortization periods for associated regulatory assets and liabilities following AMI implementation. The Parties agree it is reasonable to amortize the AMI-related depreciation of the capital and initial software/networking assets, including meters, over a 15-year period.

(F) The Utilities will maintain current data use and customer service disconnection policies, and will address possible changes to such policies, if any, in their first base rate case proceedings following AMI implementation or other proceedings to address the AMI revenue requirement following the implementation of the AMI project.

(G) The Utilities 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 the result that customers will not sustain an increase in the combined revenue requirements associated with implementing the AMI project.

(H) The Parties recognize and agree that in approving this AMI ratemaking proposal the Commission is not foregoing its authority to review the costs, regulatory assets, and regulatory liabilities for ratemaking purposes in future base rate cases or other regulatory proceedings.

(I) The Parties agree that the Utilities' requested AMI-related certificates of public convenience and necessity and other AMI-related relief requested in the Utilities' Applications should be granted.

(J) The Utilities agree to work with Walmart and other interested Parties to improve the functionality of customer usage data, including evaluating the potential for (i) implementing Green Button Connect My Data functionality and (ii) allowing customers with multiple locations to obtain their usage data through a single download.

5.3. Electric Plant Retirements and Retirement Rider. The Parties agree that the Utilities remain responsible for retirement decisions regarding electric plant, and in particular regarding electric generating units and stations. Also, the Parties recognize that using depreciation rates as agreed in this Stipulation for Mill Creek Unit 1, Mill Creek Unit 2, and E.W. Brown Unit 3 could result in significant remaining net book value and uncollected decommissioning costs for these generating assets retired after the date of this Stipulation. Therefore, the Utilities shall be authorized to recover the Retirement Costs of such retired assets and other site-related assets that will not continue in use through a Retired Asset Recovery Rider (attached hereto as Stipulation Exhibits 8 (KU) and 9 (LG&E)) until the Retirement Costs are fully recovered. "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.

(A) The Retirement Costs exclusive of ADIT are to be recorded as regulatory assets. The Retirement Costs inclusive of ADIT shall be recovered on a levelized basis, including a weighted average cost of capital carrying cost using the most recently approved base rate return on equity. The recovery period for each retired generating unit shall be ten years from the retirement date of the unit.

(B) The Retired Asset Recovery Rider will include a credit for the depreciation expense and rate of return component for each retired unit embedded in base rates at that time, but no credit for any other expense embedded in base rates.

(C) The Utilities will use best efforts to minimize the cost of dismantling and to maximize salvage credits.

(D) The Retired Asset Recovery Rider will use the Group 1 and Group 2 methodology for revenue allocation used in the Utilities' Environmental Cost Recovery Surcharges.

5.4. Lighting Issues.

(A) As shown in Stipulation Exhibit 6 (LG&E electric), LG&E will implement a one-time LED conversion fee of $260.00 under Rate LS rather than the filed one-time conversion fee of $277.29. This lower conversion fee, along with the stipulated LG&E LS & RLS rates, is expected to support Louisville Metro to reach its goal of converting all non-LED fixtures to LED fixtures over a multi-year period, subject to negotiations between LG&E and Louisville Metro regarding the number of fixture conversions per year.

(B) As shown in Stipulation Exhibit 5 (KU) and Stipulation Exhibit 6 (LG&E electric), the Utilities will reduce their proposed monthly LED conversion fees under Rate LS to $3.29 for KU and $4.62 LG&E.

(C) As shown in Stipulation Exhibit 5 (KU) and Stipulation Exhibit 6 (LG&E electric), the Utilities will add a new LED offering to Rate LS to replace their current 100W HPS Cobra offering.

(D) The Utilities commit to conduct a competitive bidding process for street lighting fixtures every five years and will complete such a competitive bid process prior to the Utilities' filing of the next general adjustment of base rates.

(E) The Utilities commit to have their information technology personnel work with their LFUCG and Louisville Metro counterparts to explore opportunities to allow streetlight outage notifications from LFUCG and Louisville Metro to flow more directly through to the Utilities.

5.5. Coal Mining Economic Development Options. The Utilities agree to work with their coal-mining customers regarding possible economic development options under the Utilities' existing tariffs. Any such option will ensure that the new rate will provide a contribution to the recovery of fixed costs and will be flexible and time-limited. To the extent any such mutually agreed economic development options require Commission approval, the Utilities commit to seek the necessary approval.

5.6. Stakeholder Process to Consider Peak-Time Rebates and an On-Bill Financing Program. The Utilities commit to engage in a stakeholder process using the Utilities' existing DSM Advisory Committee for their next DSM filings to consider and evaluate Peak-Time Rebates and an on-bill financing program.

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.

5.8. Issues Explicitly Not Addressed by this Stipulation and to Be Addressed at Hearing. The Parties agree that the Utilities' net metering proposals (Riders NMS-1 and NMS-2) and qualifying facility tariff provisions (Riders SQF and LQF) are not addressed by this Stipulation and may be addressed by any or all Parties at hearing in these proceedings. Because these issues are to be addressed at hearing, the related electric tariff sheets (Sheet Nos. 55-55.3, 56-56.1, 57, 58, and 108-108.5) are not included in Stipulation Exhibit Nos. 5 and 6.

5.9. All Other Relief Requested by Utilities to Be Approved as Filed. 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.

ARTICLE VI. MISCELLANEOUS PROVISIONS

6.1. Except as specifically stated otherwise in this Stipulation, entering into this Stipulation shall not be deemed in any respect to constitute an admission by any of the Parties that any computation, formula, allegation, assertion or contention made by any other party in these Rate Proceedings is true or valid.

6.2. The Parties agree that the foregoing Stipulation represents a fair, just, and reasonable resolution of the issues addressed herein and request that the Commission approve the Stipulation.

6.3. Following the execution of this Stipulation, the Parties shall cause the Stipulation to be filed with the Commission on or about April 19, 2021, together with a request to the Commission for consideration and approval of this Stipulation for rates to become effective for service rendered on and after July 1, 2021.

6.4. This Stipulation is subject to the acceptance of, and approval by, the Commission. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Stipulation be accepted and approved. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation, and all Parties commit to work in good faith to address and remedy promptly any such perceived violation. In all events, counsel for all Parties will represent to the Commission that the Stipulation is a fair, just, and reasonable means of resolving all issues in these proceedings that are the subject of this Stipulation and will clearly and definitively ask the Commission to accept and approve the Stipulation as such.

6.5. If the Commission issues an order adopting this Stipulation in its entirety and without additional conditions, each of the Parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to such order.

6.6. If the Commission does not accept and approve this Stipulation in its entirety, then any adversely affected Party may withdraw from the Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. If any Party timely seeks rehearing of or appeals the Commission's order, all Parties will continue to have the right to withdraw until the conclusion of all rehearings and appeals. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearings and appeals, all Parties that have not withdrawn will continue to be bound by the terms of the Stipulation as modified by the Commission's order.

6.7. If the Stipulation is voided or vacated for any reason after the Commission has approved the Stipulation, none of the Parties will be bound by the Stipulation.

6.8. The Stipulation shall in no way be deemed to affect or diminish the jurisdiction of the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

6.9. The Stipulation shall inure to the benefit of and be binding upon the Parties hereto and their successors and assigns.

6.10. The Stipulation constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations, or agreements made prior hereto or contemporaneously herewith shall be null and void and shall be deemed to have been merged into the Stipulation.

6.11. The Parties agree that, for the purpose of the Stipulation only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation.

6.12. The Parties agree that neither the Stipulation nor any of its terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein, the approval of this Stipulation, or a Party's compliance with this Stipulation. This Stipulation shall not have any precedential value in this or any other jurisdiction.

6.13. The signatories hereto warrant that they have appropriately informed, advised, and consulted their respective Parties in regard to the contents and significance of this Stipulation and based upon the foregoing are authorized to execute this Stipulation on behalf of their respective Parties.

6.14. The Parties agree that this Stipulation is a product of negotiation among all Parties hereto, and no provision of this Stipulation shall be strictly construed in favor of or against any Party. Notwithstanding anything contained in the Stipulation, the Parties recognize and agree that the effects, if any, of any future events upon the operating income of the Utilities are unknown and this Stipulation shall be implemented as written.

6.15. The Parties agree that this Stipulation may be executed in multiple counterparts.

[Signature Pages Follow]

APPENDIX A: LIST OF STIPULATION EXHIBITS

Stipulation Exhibit 1:	Depreciation rates for KU and LG&E
Stipulation Exhibit 2:	KU Electric Revenue Allocation and Rate Design Schedules
Stipulation Exhibit 3:	LG&E Electric Revenue Allocation and Rate Design Schedules
Stipulation Exhibit 4:	LG&E Gas Revenue Allocation and Rate Design Schedules
Stipulation Exhibit 5:	KU Tariff Sheets (except Sheet Nos. 55-55.3, 56-56.1, 57, 58, and 108-108.5)
Stipulation Exhibit 6:	LG&E Electric Tariff Sheets (except Sheet Nos. 55-55.3, 56-56.1, 57, 58, and 108-108.5)
Stipulation Exhibit 7:	LG&E Gas Tariff Sheets
Stipulation Exhibit 8:	KU Retired Asset Recovery Rider (Rider RAR)
Stipulation Exhibit 9:	LG&E Retired Asset Recovery Rider (Rider RAR)

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

By: Kendrick R. Riggs
Kendrick R. Riggs

-and-

By: Allyson K. Sturgeon
Allyson K. Sturgeon

Attorney General for the Commonwealth of Kentucky, by and through the Office of Rate Intervention

HAVE SEEN AND AGREED:

By: John G Horne II

Lawrence W. Cook
J. Michael West
Angela M. Goad
John G. Horne II

United States Department of Defense and All Other Federal Executive Agencies

HAVE SEEN AND AGREED:

By: ______________________________

Emily W. Medlyn
G. Houston Parrish

Kentucky Industrial Utility Customers, Inc.

HAVE SEEN AND AGREED:

By: ______________________________
Michael L. Kurtz
Kurt J. Boehm
Jody Kyler Cohn

Kentuckians for the Commonwealth,
Kentucky Solar Energy Society,
Mountain Association, and
Metropolitan Housing Coalition

HAVE SEEN AND AGREED:

By: ___________________________
Tom FitzGerald

Kentucky Solar Industries Association, Inc.

HAVE SEEN AND AGREED:

By: ______________________________

Randal A. Strobo
Clay A. Barkley
David E. Spenard

The Kroger Co.

HAVE SEEN AND AGREED:

By: Robert C. Moore
Robert C. Moore

Lexington-Fayette Urban County Government

HAVE SEEN AND AGREED:

By: M. Todd Osterloh

James W. Gardner
M. Todd Osterloh

Susan Speckert
David J. Barberie

Subject to approval of the Urban County Council

Louisville/Jefferson County Metro Government

HAVE SEEN AND AGREED:

By: ______________________________
James W. Gardner
M. Todd Osterloh

Jeff Derouen
Lauren Givhan

Subject to approval of Louisville Metro

Sierra Club

HAVE SEEN AND AGREED:

By: ____________________________________

Joe F. Childers

Matthew E. Miller

Walmart Inc.

HAVE SEEN AND AGREED:

By: ______________________________

Don C.A. Parker
Carrie H. Grundmann
Barry N. Naum

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00350 DATED JUN 30 2021

The following rates and charges are prescribed for the customers in the area served by Louisville Gas and Electric Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under the authority of this Commission prior to the effective date of this Order.

ELECTRIC SERVICE RATES

SCHEDULE RS
RESIDENTIAL SERVICE

Basic Service Charge per Day	$ 0.45
Energy Charge per kWh	
Infrastructure	$ 0.06917
Variable Energy	$ 0.03245
Total	$ 0.10162

SCHEDULE RTOD-ENERGY
RESIDENTIAL TIME-OF-DAY ENERGY SERVICE

Basic Service Charge per Day	$ 0.45
Energy Charge per kWh	
Off-Peak Hours – Infrastructure	$ 0.04882
Off-Peak Hours – Variable	$ 0.03245
Total	$ 0.08127
On-Peak Hours (Infrastructure)	$ 0.14545
On-Peak Hours (Variable)	$ 0.03245
Total	$ 0.17790

SCHEDULE RTOD-DEMAND
RESIDENTIAL TIME-OF-DAY DEMAND SERVICE

Basic Service Charge per Day	$ 0.45
Energy charge per kWh	
Infrastructure	$ 0.02095

Variable	$ 0.03245
Total	$ 0.05340
Demand Charge per kW	
Base Hours	$ 4.18
Peak Hours	$ 9.15

SCHEDULE VFD
VOLUNTEER FIRE DEPARTMENT

Basic Service Charge per Day	$ 0.45
Energy Charge per kWh	
Infrastructure	$ 0.06917
Variable Energy	$ 0.03245
Total	$ 0.10162

SCHEDULE GS
GENERAL SERVICE RATE

Basic Service Charge per Day	
Single Phase	$ 1.16
Three Phase	$ 1.85
Energy charge per kWh	
Infrastructure	$ 0.08577
Variable	$ 0.03340
Total	$ 0.11917

SCHEDULE GTOD-ENERGY
GENERAL TIME-OF-DAY ENERGY SERVICE

Basic Service Charge per Day	
Single Phase	$ 1.16
Three Phase	$ 1.85
Energy Charge per kWh	
Off-Peak Hours – Infrastructure	$ 0.04694
Off-Peak Hours – Variable	$ 0.03340
Total	$ 0.08034
On-Peak Hours (Infrastructure)	$ 0.21271
On-Peak Hours (Variable)	$ 0.03340
Total	$ 0.24611

SCHEDULE GTOD-DEMAND
GENERAL TIME-OF-DAY DEMAND SERVICE

Basic Service Charge per Day	
Single Phase	$ 1.16
Three Phase	$ 1.85
Energy Charge per kWh	
Off-Peak Hours – Infrastructure	$ 0.02587
Off-Peak Hours – Variable	$ 0.03340
Total	$ 0.05927
Demand Charge per kW	
Base Hours	$ 5.37
Peak Hours	$ 11.75

SCHEDULE PS
POWER SERVICE

Secondary Service:	
Basic Service Charge per Day	$ 2.95
Demand Charge per kW:	
Summer Rate	$ 27.52
Winter Rate	$ 24.24
Energy Charge per kWh	$ 0.03442
Primary Service:	
Basic Service Charge per Day	$ 7.89
Demand Charge per kW:	
Summer Rate	$24.10
Winter Rate	$20.99
Energy Charge per kWh	$ 0.03359

SCHEDULE TODS
TIME-OF-DAY SECONDARY SERVICE

Basic Service Charge per Day	$ 6.58
Maximum Load Charge per kVA:	
Base Demand Period	$ 3.76
Intermediate Demand Period	$ 7.47
Peak Demand Period	$ 9.68
Energy Charge per kWh	$ 0.03038

SCHEDULE TODP
TIME-OF-DAY PRIMARY SERVICE

Basic Service Charge per Day	$ 10.84
Maximum Load Charge per kVA:	
Base Demand Period	$ 2.45
Intermediate Demand Period	$ 7.49
Peak Demand Period	$ 9.78
Energy Charge per kWh	$ 0.02742

SCHEDULE RTS
RETAIL TRANSMISSION SERVICE

Basic Service Charge per Day	$ 49.28
Maximum Load Charge per kVA:	
Base Demand Period	$ 1.93
Intermediate Demand Period	$ 7.17
Peak Demand Period	$ 9.35
Energy Charge per kWh	$ 0.02705

SCHEDULE FLS
FLUCTUATING LOAD SERVICE

Primary:

Basic Service Charge per Day	$ 10.84
Maximum Load Charge per kVA:	
Base Demand Period	$ 2.32
Intermediate Demand Period	$ 7.10
Peak Demand Period	$ 9.34
Energy Charge per kWh	$ 0.03236

Transmission:

Basic Service Charge per Day	$ 49.28
Maximum Load Charge per kVA:	
Base Demand Period	$ 1.67
Intermediate Demand Period	$ 6.76
Peak Demand Period	$ 8.92
Energy Charge per kWh	$ 0.03183

SCHEDULE LS
LIGHTING SERVICE

Rate per Light per Month: (Lumens Approximate)

Overhead:

	Fixture Only
Light Emitting Diode	
5,500 – 8,200 Lumens – Cobra Head	$ 10.23
13,000 – 16,500 Lumens – Cobra Head	$ 12.19
22,000 – 29,000 Lumens – Cobra Head	$ 15.46
4,500 – 6,000 Lumens – Open Bottom	$ 9.27
2,500 – 4,000 Lumens – Cobra Head	$ 8.89
4,000 – 6,000 Lumens – Cobra Head	$ 9.43
4,500 – 6,000 Lumens – Directional (Flood)	$ 11.71
14,000 – 17,500 Lumens – Directional (Flood)	$ 13.63
22,000 – 28,000 Lumens – Directional (Flood)	$ 15.99
35,000 – 50,000 Lumens – Directional (Flood)	$ 22.66
Wood Pole	
PL6	$ 6.88

Underground:

	Fixture Only
Light Emitting Diode	
2,500 – 4,000 Lumens – Cobra Head	$ 4.21
4,000 – 6,000 Lumens – Cobra Head	$ 4.72
5,500 – 8,200 Lumens – Cobra Head	$ 5.55
13,000 – 16,500 Lumens – Cobra Head	$ 7.52
22,000 – 29,000 Lumens – Cobra Head	$ 10.79
4,000 – 7,000 Lumens Colonial, 4-Sided	$ 7.23
4,000 – 7,000 Lumens – Acorn	$ 7.04
4,000 – 7,000 Lumens – Contemporary	$ 6.93
8,000 – 11,000 Lumens – Contemporary	$ 8.27
13,500 – 16,500 Lumens – Contemporary	$ 10.16
21,000 – 28,000 Lumens – Contemporary	$ 14.61
45,000 – 50,000 Lumens – Contemporary	$ 20.30
4,500 – 6,000 Lumens – Directional (Flood)	$ 8.08
14,000 – 17,500 Lumens – Directional (Flood)	$ 9.99
22,000 – 28,000 Lumens – Directional (Flood)	$ 12.36
35,000 – 50,000 Lumens – Directional (Flood)	$ 19.02
4,000 – 7,000 Lumens – Victorian	$ 25.36
4,000 – 7,000 Lumens – London	$ 26.93

Pole Charges	
Cobra	$ 26.00
Contemporary (Short)	$17.49
Contemporary (Tall)	$22.62
Post Top – Decorative Smooth	$15.52
Post Top – Historic Fluted	$19.15

One-Time Conversion Fee	$260.00
Monthly Conversion Fee	$4.62

SCHEDULE RLS
RESTRICTED LIGHTING SERVICE

Overhead:

	Fixture Only	Fixture & Wood Pole	Fixture & Orn. Pole
Mercury Vapor:			
8,000 Lumens – Cobra/Open Bottom	$11.67		
13,000 Lumens - Cobra Head	$13.21		
25,000 Lumens - Cobra Head	$16.17		
60,000 Lumens - Cobra Head	$32.66		
25,000 Lumens – Directional	$18.39		
60,000 Lumens – Directional	$33.97		
4,000 Lumens - Open Bottom	$10.13		
Metal Halide:			
12,000 Lumens - Directional	$15.99	$18.86	
32,000 Lumens - Directional	$22.06	$24.52	$ 32.52
107,800 Lumens - Directional	$46.12	$49.55	
High Pressure Sodium:			
16,000 Lumens - Cobra Head	$15.48		
28,500 Lumens - Cobra Head	$18.02		
50,000 Lumens - Cobra Head	$20.53		
9,500 Lumens - Open Bottom	$13.74		
16,000 Lumens – Directional	$16.51		
50,000 Lumens – Directional	$21.42		

Underground:

	Fixture Only	Decorative Pole	Fluted Pole
High Pressure Sodium:			
16,000 Lumens – Cobra/Contemporary		$29.62	
28,500 Lumens – Cobra/Contemporary		$32.49	
50,000 Lumens – Cobra/Contemporary		$37.06	

5,800 Lumens – Coach/Acorn		$17.99	
9,500 Lumens – Coach/Acorn		$21.38	
16,000 Lumens – Coach/Acorn		$26.10	
120,000 Lumens – Contemporary	$50.65	$83.99	
9,500 Lumens – Acorn/Bronze		$28.84	
16,000 Lumens – Acorn/Bronze		$30.13	
5,800 Lumens – Victorian	$24.42	$37.57	$38.31
9,500 Lumens – Victorian	$24.89	$39.83	$42.99
5,800 Lumens – London	$24.00	$38.62	$40.77
9,500 Lumens – London	$25.43	$39.56	$40.74
5,800 Lumens – Colonial 4-Sided		$23.87	
9,500 Lumens – Colonial 4-Sided		$24.62	
16,000 Lumens – Colonial 4-Sided		$24.52	
5,800 Lumens – Acorn		$24.30	
9,500 Lumens – Acorn		$26.89	
16,000 Lumens – Acorn		$26.65	
4,000 Lumens – Dark Sky		$28.38	
9,500 Lumens – Dark Sky		$28.78	
16,000 Lumens – Cobra Head		$31.25	
28,500 Lumens – Cobra Head		$33.73	
50,000 Lumens – Cobra Head		$40.00	
16,000 Lumens – Contemporary	$19.38	$35.22	
28,500 Lumens – Contemporary	$21.46	$37.98	
50,000 Lumens – Contemporary	$25.82	$44.07	
Mercury Vapor			
8,000 Lumens – Cobra Head		$20.26	
13,000 Lumens – Cobra Head		$22.81	
25,000 Lumens – Cobra Head		$26.53	
4,000 Lumens – Coach		$14.87	
8,000 Lumens – Coach		$16.77	
Metal Halide			
12,000 Lumens – Contemporary	$17.73	$28.98	
107,800 Lumens – Contemporary	$49.32	$61.19	
32,000 Lumens – Contemporary	$23.98	$35.89	

Incandescent	
1,500 Lumens – Continental Jr.	$10.64
6,000 Lumens – Continental Jr.	$15.15
Victorian/London Bases	
Old Town	$3.88
Chesapeak	$4.10
Victorian/London (Westchester/Norfolk)	$3.97
Poles	
10' Smooth Pole	$11.59
10' Fluted Pole	$13.83

SCHEDULE TE
TRAFFIC ENERGY SERVICE

Basic Service Charge per Day	$ 0.13
Energy Charge per kWh	$ 0.08654

RC
REDUNDANT CAPACITY

Charge per kW/kVA per month	
Secondary Distribution	$ 1.90
Primary Distribution	$ 1.28

LE
LIGHTING SERVICE

Energy Charge per kWh	$0.07293

EVSE
ELECTRIC VEHICLE SUPPLY EQUIPMENT

Monthly Charging Unit Fee:

Networked Charger:	
Single Charger	$133.36
Dual Charger	$195.48
Non-Networked Charger:	
Single Charger:	$ 80.40

EVSE-R
ELECTRIC VEHICLE SUPPLY EQUIPMENT

Monthly Charging Unit Fee:

Networked Charger:	
Single Charger	$122.80
Dual Charger	$174.37
Non-Networked Charger:	
Single Charger:	$ 30.71

EVC-FAST
ELECTRIC VEHICLE FAST CHARGING SERVICE

Fee for use per kWh	$ 0.25

ERS
ECONOMIC RELIEF SURCREDIT

All Rate Schedules per 100 cubic feet	$ (0.00343)

OSL
OUTDOOR SPORTS LIGHTING SERVICE

Secondary Service:	
Basic Service Charge per Day	$ 2.96
Maximum Load Charge per kW:	
Peak Demand Period	$ 23.14
Base Demand Period	$ 3.38
Energy Charge per kWh	$ 0.03038
Primary Service:	
Basic Service Charge per Day	$ 7.89
Maximum Load Charge per kW:	
Peak Demand Period	$ 17.17
Base Demand Period	$ 2.21
Energy Charge per kWh	$ 0.02742

EF
EXCESS FACILITIES

Percentage With No Contribution-In-Aid-of-Constructing	1.19%
Percentage With Contribution-In-Aid-of-Construction	0.52%

SPECIAL CONTRACT

Energy Charge per kWh	$ 0.03228
Demand Charge per kW	$ 17.61

Other Charges

Returned Payment Charge	$ 3.70
Meter Test Charge	$ 79.00
Disconnect/Reconnect Charge	
Electric Only	$ 32.00
Gas and Electric	$ 32.00
Temporary Suspension Disconnect/Reconnect	$ 32.00
Remote Disconnect/Reconnect with Reconnection Capability	$ 0.00
Temporary Suspension with Remote Reconnection Capability	$ 0.00
Meter Pulse Charge	$ 21.00
Unauthorized Connection Charge	
No Meter Replacement	$ 49.00
Single-Phase Meter Replacement	$ 70.00
Single-Phase AMR Meter	$ 91.00
Single-Phase AMI Meter	$153.00
Three-Phase Meter Replacement	$159.00
AMI Opt-Out	
One Time Fee	$ 35.00
Monthly Fee per Delivery Point	$ 12.00
TS - Temporary-to-Permanent	15.00%
TS – Seasonal	100.00%
Late Payment Charge	
Rates RS, RTOD-Energy, RTOD-Demand, VFD, GS GTOD-Energy, GTOD-Demand, PSA	3.00%
Rates PS, TODS, TODP, RTS, FLS OSL	1.00%

GAS SERVICE RATES

RATE RGS
RESIDENTIAL GAS SERVICE

Basic Service Charge per Day	$ 0.65
Distribution Charge per Ccf	$ 0.50883

RATE VFD
VOLUNTEER FIRE DEPARTMENT SERVICE

Basic Service Charge per Day	$ 0.65

Distribution Charge per Ccf	$ 0.50883

RATE CGS
FIRM COMMERCIAL GAS SERVICE

Basic Service Charge per Day	
Meters < 5000 cf/hr	$ 2.30
Meters >= 5000 cf/hr	$ 11.00
Distribution Charge per Ccf	
On Peak	$ 0.38207
Off Peak	$ 0.33207

Rider TS-2 Gas Transportation Service

Administrative Charge per Month	$ 550.00
Basic Service Charge per Day	
Meters < 5000 cf/hr	$ 2.30
Meters >= 5000 cf/hr	$ 11.00
Distribution Charge per Mcf	$ 3.8207
Pipeline Supplier’s Demand Component per Mcf	$ 0.8774

RATE IGS
FIRM INDUSTRIAL GAS SERVICE

Basic Service Charge per Day	
Meters < 5000 cf/hr	$ 5.42
Meters >= 5000 cf/hr	$ 24.64
Distribution Charge per Ccf	
On Peak	$ 0.27023
Off Peak	$ 0.22023

Rider TS-2 Gas Transportation Service

Administrative Charge per Month	$ 550.00
Basic Service Charge per Day	
Meters < 5000 cf/hr	$ 5.42
Meters >= 5000 cf/hr	$ 24.64
Distribution Charge per Mcf	$ 2.7023
Pipeline Supplier’s Demand Component per Mcf	$ 0.8774

RATE AAGS
AS-AVAILABLE GAS SERVICE

Basic Service Charge per month	$ 630.00
Distribution Charge per Mcf	$ 1.7739

Rider TS-2 Gas Transportation Service

Administrative Charge per Month	$ 550.00
Basic Service Charge per Month	$ 630.00
Distribution Charge per Mcf	$ 1.7739
Pipeline Supplier's Demand Component per Mcf	$ 0.8774

RATE SGSS
SUBSTITUE GAS SALES SERVICE

For commercial customers:

Customer Charge per Month	$ 335.00
Demand Charge per Mcf	$ 7.17
Distribution Charge per Mcf	$ 0.4106

For industrial customers:

Customer Charge per Month	$ 750.00
Demand Charge per Mcf	$ 10.89
Distribution Charge per Mcf	$ 0.3100

RATE FT
FIRM TRANSPORTATION SERVICE

Administrative Charge	$ 550.00
Monthly Basic Service Charge	$ 750.00
Distribution Charge per Mcf	$ 0.0456
Demand Charge per Mcf	$ 7.08

RATE DGGS
DISTRIBUTION GENERATION GAS SERVICE

Basic Service Charge per Day	
Meters < 5000 cf/hr	$ 165.00
Meters >= 5000 cf/hr	$ 750.00
Demand Charge per Mcf	$ 10.89
Distribution Charge per Ccf	$ 0.03100

Rider TS-2 Gas Transportation Service

Administrative Charge per Month	$ 550.00
Basic Service Charge per Day	
Meters < 5000 cf/hr	$ 165.00
Meters >= 5000 cf/hr	$ 750.00
Distribution Charge per Mcf	
On Peak	$ 0.3100
Pipeline Supplier'	$ 0.8774

RATE LGDS
LOCAL GAS DELIVERY SERVICE

Administrative Charge per Month	$ 550.00
Basic Service Charge per Month	$ 750.00
Demand Charge per Mcf	$ 7.08
Distribution Charge per Mcf	$ 0.0456

INTRA-COMPANY SPECIAL CONTRACTS

Basic Service Charge per Month	$ 750.00
Demand Charge per Mcf	$ 10.89
Distribution Charge per Mcf	$ 0.3100

GLT
GAS LINE TRACKER

Distribution Project ($/delivery Point)	
RGS, VFD	$ 1.01
CGS, SGSS	$ 5.02
IGS, AAGS, DGGS	$ 60.10
FT, LGDS	$ 0.00
Transmission Project ($/Ccf)	
RGS, VFD	$ 0.00017
CGS, SGSS	$ 0.00014
IGS, AAGS, DGGS	$ 0.00008
FT, LGDS	$ 0.00001

ERS
ECONOMIC RELIEF SURCREDIT

All Rate Schedules per 100 cubic feet	$ (0.00619)

EF
EXCESS FACILITIES

Percentage with No Contribution-In-Aid-of-Constructing	1.12%
Percentage with Contribution-In-Aid-of-Construction	0.44%

OTHER CHARGES

Disconnect/Reconnect Charge	
Gas Only	$ 32.00
Gas and Electric	$ 32.00
Temporary Suspension (RGS, VFD, CGD, IGS, AAGS)	
Gas Only	$ 32.00
Gas and Electric	$ 32.00
Meter Test Charge	$ 112.86

Returned Payment Charge	$ 3.70
Inspection Charge	$ 155.00
Additional Trip Charge (FT, TS-2, GMPS)	$ 155.00
Unauthorized Connection Charge	
No Meter Replacement	$ 49.00
Meter Replacement	$ 114.00
Gas Meter Pulse	
Rate FT or Rider TS-2	$ 8.00
Other	$ 28.00
AMI Opt Out	
One Time Fee	$ 33.00
Monthly Fee	$ 5.00
Late Payment Charge	
Rates RGS, VFD, CGS, IGS, SGSS	3.00%
Rates AAGS, FT, DGGS, LGDS, PS-TS-2, PS-FT	1.00%

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00350 DATED JUN 30 2021

Adjustments to LG&E's Cost of Capital (Electric Operations)

I. Capital Structure, Cost of Capital, and Gross Revenue Conversion Factor Per Filing

	Adjusted Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	44,119,105	1.27%	0.460%	0.01%	0.01%
Long Term Debt	1,579,023,577	45.54%	4.042%	1.84%	1.85%
Common Equity	1,844,129,753	53.19%	10.000%	5.32%	7.12%
Total Capital	3,467,272,435	100.00%		7.17%	8.97%

II. Reduce Long-Term Debt Rate

	Adjusted Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	44,119,105	1.27%	0.460%	0.01%	0.01%
Long Term Debt	1,579,023,577	45.54%	4.000%	1.82%	1.83%
Common Equity	1,844,129,753	53.19%	10.000%	5.32%	7.12%
Total Capital	3,467,272,435	100.00%		7.15%	8.95%

Change in Grossed Up COC	-0.02%
Adjusted Capitalization	3,467,272,435
Change in Revenue Requirement	(666,090)

I. Reduce Return on Common Equity to 9.425%

	Adjusted Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	44,119,105	1.27%	0.460%	0.01%	0.01%
Long Term Debt	1,579,023,577	45.54%	4.000%	1.82%	1.83%
Common Equity	1,844,129,753	53.19%	9.425%	5.01%	6.71%
Total Capital	3,467,272,435	100.00%		6.84%	8.54%

Change in Grossed Up COC	-0.41%
Adjusted Capitalization	3,467,272,435
Change in Revenue Requirement	(14,186,079)

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00350 DATED JUN 30 2021

Adjustments to LG&E's Cost of Capital (Gas Operations)

I. LG&E Capital Structure, Cost of Capital, and Gross Revenue Conversion Factor Per Filing

	Adjusted LG&E Gas Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	13,510,889	1.27%	0.460%	0.01%	0.01%
Long Term Debt	483,554,981	45.54%	4.042%	1.84%	1.85%
Common Equity	564,740,224	53.19%	10.000%	5.32%	7.12%
Total Capital	1,061,806,095	100.00%		7.17%	8.97%

II. Reduce Long-Term Debt Rate

	Adjusted LG&E Gas Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	13,510,889	1.27%	0.460%	0.01%	0.01%
Long Term Debt	483,554,981	45.54%	4.000%	1.82%	1.83%
Common Equity	564,740,224	53.19%	10.000%	5.32%	7.12%
Total Capital	1,061,806,095	100.00%		7.15%	8.95%

Change in Grossed Up COC	-0.02%
Adjusted Capitalization	1,061,806,095
Change in Revenue Requirement	(203,981)

III. Reduce Return on Common Equity to 9.425%

	Adjusted LG&E Gas Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	13,510,889	1.27%	0.460%	0.01%	0.01%
Long Term Debt	483,554,981	45.54%	4.000%	1.82%	1.83%
Common Equity	564,740,224	53.19%	9.425%	5.01%	6.71%
Total Capital	1,061,806,095	100.00%		6.84%	8.54%

Change in Grossed Up COC	-0.41%
Adjusted Capitalization	1,061,806,095
Change in Revenue Requirement	(4,344,298)

APPENDIX E

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00350 DATED JUN 30 2021

Electric Operations

	Adjusted Stipulation Amount	Stipulation Amount	Difference
	($ Millions)		
Base Rate Increase Requested by LG&E - Electric Operations	128.40	128.40	-
Reduce Pension and OPEB Expenses	(3.00)	(3.00)	-
Reduce Depreciation Expense to Reflect Present Rates for Mill Creek 1 & 2	(36.50)	(36.50)	-
Remove Forecasted Legal Fees	(0.96)	-	(0.96)
Remove EEI Dues	(0.33)	-	(0.33)
Adjust Rate Case Expense to Actual	(0.04)	-	(0.04)
Reduce LTD Rate Related to June 30, 2021 Issuance	(0.67)	(0.60)	(0.07)
Reduce Return on Equity from 10.0%	(14.19)	(11.00)	(3.19)
Total Adjustments to Base Rate Increase	(55.68)	(51.10)	(4.58)
Base Rate Increase After Adjustments	72.72	77.30	(4.58)

Gas Operations

	Adjusted Stipulation Amount	Stipulation Amount	Difference
	($ Millions)		
Base Rate Increase Requested by LG&E - Gas Operations	33.00	33.00	-
Reduce Pension and OPEB Expenses to 2020 Levels	(1.00)	(1.00)	-
Reduce Increase for Maintenance of Mains in Account 868	(4.20)	(4.20)	-
Remove Forecasted Legal Fees	(2.88)	-	(2.88)
Adjust Rate Case Expense to Actual	(0.01)	-	(0.01)
Reduce LTD Rate Related to June 30, 2021 Issuance	(0.20)	(0.20)	(0.00)
Reduce Return on Equity from 10.0%	(4.34)	(3.40)	(0.94)
Total Adjustments to Companies Base Rate Increases	(12.64)	(8.80)	(3.84)
Base Rate Increase After Adjustments	20.36	24.20	(3.84)

APPENDIX F

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00350 DATED JUN 30 2021

AMI quantitative benefits monitored pursuant to ordering paragraph 7 of this Order.

BENEFITS	CITATION TO CASE RECORD
Reduced meter reading expenses	Bellar Direct Testimony at 54 and Exhibit LEB3 at A13-A15; Saunders Direct Testimony at 32-33
Ability to disconnect/reconnect remotely	Wolfe Direct Testimony at 28; Saunders Direct Testimony at 28
Reduced field service costs	Bellar Direct Testimony at 55 and Exhibit LEB3 at A15–A16; Wolfe Direct Testimony at 24–25
Avoided meter costs.	Bellar Direct Testimony at 55
Fuel savings from decreased customer usage.	Bellar Direct Testimony at 55 and Exhibit LEB3 at A18–A20
Conservative Voltage Reduction.	Bellar Direct Testimony at 61; Wolfe Direct Testimony at 21
Time of day rates	Bellar Testimony at 58
Electric Distribution Operations	Bellar Direct Testimony, Exhibit LEB3 at A17–A18
Improved outage response	Wolfe Direct Testimony at 22–24 and Exhibit JKW2 at 15–27
Management and prediction of outages, overloads, and shortfalls of transmission and distribution assets.	Wolfe Direct Testimony at 25–27
Data availability to customers within 406 hours	Bellar Direct Testimony at 58
Innovative Rate Design	Bellar Direct Testimony at 58
Reduced Theft and Earlier Detection	Bellar Direct Testimony at 60

*Honorable Allyson K Sturgeon
Managing Senior Counsel - Regulatory &
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202

*Emily W Medlyn
General Attorney
U.S. Army Legal Services Agency Regul
9275 Gunston Road
Fort Belvoir, VIRGINIA 22060

*John Horne
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Angela M Goad
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Thomas J FitzGerald
Counsel & Director
Kentucky Resources Council, Inc.
Post Office Box 1070
Frankfort, KENTUCKY 40602

*Honorable Kurt J Boehm
Attorney at Law
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

*Barry Alan Naum
Spilman Thomas & Battle, PLLC
1100 Brent Creek Blvd., Suite 101
Mechanicsburg, PENNSYLVANIA 17050

*G. Houston Parrish
Labor Law Attorney
Office of the Staff Judge Advocate, B
50 3rd Avenue
Fort Knox, KENTUCKY 40121

*Honorable Kendrick R Riggs
Attorney at Law
Stoll Keenon Ogden, PLLC
2000 PNC Plaza
500 W Jefferson Street
Louisville, KENTUCKY 40202-2828

*Clay A. Barkley
Strobo Barkley PLLC
239 South 5th Street
Ste 917
Louisville, KENTUCKY 40202

*Jeff Derouen
200 S. 5th St. Suite 200 N
Louisville, KENTUCKY 40202

*Larry Cook
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Carrie H Grundmann
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, NORTH CAROLINA 27103

*James W Gardner
Sturgill, Turner, Barker & Moloney, PLLC
333 West Vine Street
Suite 1400
Lexington, KENTUCKY 40507

*Lauren Givhan
200 S. 5th St. Suite 200 N
Louisville, KENTUCKY 40202

*Don C A Parker
Spilman Thomas & Battle, PLLC
1100 Brent Creek Blvd., Suite 101
Mechanicsburg, PENNSYLVANIA 17050

*Jody M Kyler Cohn
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

*Matt Partymiller
President
Kentucky Solar Industries Association
1038 Brentwood Court
Suite B
Lexington, KENTUCKY 40511

*Honorable David Edward Spenard
Strobo Barkley PLLC
239 South 5th Street
Ste 917
Louisville, KENTUCKY 40202

*Joe F. Childers
Childers & Baxter PLLC
300 Lexington Building, 201 West Sho
Lexington, KENTUCKY 40507

*Matthew Miller
Sierra Club
50 F Street, NW, Eighth Floor
Washington, DISTRICT OF COLUMBIA 20001

*J. Michael West
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Louisville Gas and Electric Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40232-2010

*Honorable Michael L Kurtz
Attorney at Law
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

*M. Todd Osterloh
Sturgill, Turner, Barker & Moloney, PLLC
333 West Vine Street
Suite 1400
Lexington, KENTUCKY 40507

*Rick LoveKamp
Kentucky Utilities Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40202

*Honorable Robert C Moore
Attorney At Law
Stites & Harbison
421 West Main Street
P. O. Box 634
Frankfort, KENTUCKY 40602-0634

*Robert Conroy
Vice President, State Regulation and Rates
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202

*Randal A. Strobo
Strobo Barkley PLLC
239 South 5th Street
Ste 917
Louisville, KENTUCKY 40202

*Sara Judd
Senior Corporate Attorney
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202

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

O R D E R

Kentucky Utilities Company (KU) is a jurisdictional electric utility that generates, transmits, distributes, and sells electricity to approximately 533,000 retail customers in all or portions of 77 Kentucky counties.[1] Its most recent general rate case for electric service was Case No. 2018-00294.[2]

BACKGROUND

On October 23, 2020, KU filed a notice of its intent to file on or after November 25, 2020, an application for approval of increases in its electric rates, including changes to its electric tariffs, a Certificate of Public Convenience and Necessity (CPCN) to deploy advanced metering infrastructure (AMI), approval of certain regulatory and accounting

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[1] *Annual Electric Report of Kentucky Utilities to the Public Service Commission for the Year Ending December 31, 2020* at 5. *See also* Application at 2.

[2] Case No. 2018-00294, *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates* (Ky. PSC Apr. 30, 2019).

treatments, and establishment of a one-year surcredit.[3] On November 25, 2020, KU filed its application[4] seeking an increase in electric revenues of $170.1 million, or 10.4 percent per year for the forecasted test period compared to the operating revenues for the forecasted test period under existing electric rates.[5] KU's application also included, among other things, new rates and revisions, deletions, and additions to its electric tariffs, all to be effective January 1, 2021.[6] KU's requested rate increase is supported by a 12-month fully forecasted test period ending June 30, 2022. The base period consists of the 12 months ending February 28, 2021. As authorized by KRS 278.192(2), this base period begins not more than nine months prior to the date of the filing of the application, and is a period consisting of not less than six months of historical data and not more than six months of estimated data. The monthly residential electric bill increase due to the proposed electric base rates will be 10.6 percent, or approximately $12.85, for an average KU customer using 1,120 kilowatt-hours (kWh) of electricity.[7]

Pursuant to an Order issued on December 9, 2020, the Commission found that an investigation would be necessary to determine the reasonableness of KU's proposed rates and suspended the proposed rates for a period of six months, pursuant to KRS 278.190(2), from January 1, 2021, up to and including June 30, 2021. The

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[3] KU's Notice of Intent.

[4] Also on November 25, 2020, KU's sister company, Louisville Gas and Electric Corporation (LG&E), filed a separate application seeking an increase in its electric and gas rates. LG&E's application is docketed as Case No. 2020-00350.

[5] Direct Testimony of Kent W. Blake (Blake Testimony) at 20. *See also*, KU's Customer Notice of Rate Adjustment at 1.

[6] KU's Customer Notice of Rate Adjustment at 1.

[7] Application at 4.

December 9, 2020 Order also established a procedural schedule for processing this case. The schedule provided, among other things, a deadline for requesting intervention, discovery on KU's application, intervenor testimony, discovery on intervenor testimony, and rebuttal testimony by KU.

The following parties requested and were granted intervention: the Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General); Kentucky Industrial Utility Customers, Inc. (KIUC); Kroger Company (Kroger); Walmart, Inc. (Walmart); Lexington-Fayette Urban County Government (LFUCG); Kentucky Solar Industries Association, Inc. (KYSIA); Sierra Club; United States Department of Defense and all other Federal Executive Agencies (DOD/FEA); and Mountain Association, Kentuckians for the Commonwealth, and Kentucky Solar Energy Society (collectively Joint Intervenors).

Pursuant to an Order issued on March 29, 2021, informal conferences were held, at the request of KU, on April 15 and 16, 2021, to allow the parties to this matter and the LG&E rate matter an opportunity to discuss the issues and the possible resolution of those issues in the two non-consolidated proceedings. The parties at the informal conferences were able to come to an agreement resolving all of the issues in this proceeding as well as the LG&E proceeding except for the two companies' proposed qualifying facility tariff provisions and the net metering proposals. On April 19, 2021, KU and LG&E filed a joint motion requesting leave to file testimony supporting the Stipulation.[8]

[8] On May 7, 2021, KU and LG&E filed a Joint Errata to the Stipulation Exhibit 1 (Joint Errata), which had been filed along with the Stipulation on April 19, 2021. KU and LG&E states that they inadvertently failed to update the AMI rates agreed to in the Stipulation. The Joint Errata contains the agreed to depreciation rates for new AMI software placed in service after June 30, 2020, based on a life of 15 years.

The Commission held information sessions and public meetings for the purpose of taking public comments on April 14, 15, and 21, 2021. Due to the COVID-19 state of emergency, the information sessions and public meetings were conducted virtually.

A formal hearing was conducted on April 26, 27, and 28, 2021, for the purposes of cross-examination of witnesses and for the consideration of the Stipulation. KU filed responses to post-hearing data requests on May 19, 2021. Post-hearing briefs were filed on May 24, 2021, by KU, the Attorney General and KIUC on a joint basis, LFUCG, Sierra Club, Kroger, DOD/FEA, Walmart, KYSIA, and Joint Intervenors. Responsive briefs were filed by KU, the Attorney General and KIUC on a joint basis, Joint Intervenors, and KYSIA on June 1, 2021. The matter now stands submitted to the Commission for a decision.

LEGAL STANDARD

KU filed its application pursuant to KRS 278.020; KRS 278.180; KRS 278.190; 807 KAR 5:001, Sections 15–16; and 807 KAR 5:011. The Commission's standard of review of a utility's request for a rate increase is well established. In accordance with statutory and case law, KU is allowed to charge its customers "only 'fair, just and reasonable rates.'"[9] Further, KU bears the burden of proof to show that the proposed rate increase is just and reasonable, under KRS 278.190(3).

The Commission's standard of review of a request for a CPCN is well settled. No utility may construct or acquire any facility to be used in providing utility service to the

[9] KRS 278.030; and *Pub. Serv. Comm'n v. Com. ex rel. Conway*, 324 S.W.3d 373, 377 (Ky. 2010).

public until it has obtained a CPCN from this Commission.[10] To obtain a CPCN, a utility must demonstrate a need for such facilities and an absence of wasteful duplication.[11]

"Need" requires:

> [A] showing of a substantial inadequacy of existing service, involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed or operated.
>
> [T]he inadequacy must be due either to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service.[12]

"Wasteful duplication" is defined as "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties."[13] To demonstrate that a proposed facility does not result in wasteful duplication, we have held that the applicant must demonstrate that a thorough review of all reasonable alternatives has been performed.[14] The fundamental principle of reasonable least-cost alternative is embedded in such an analysis. Selection

[10] KRS 278.020(1).

[11] *Kentucky Utilities Co. v. Pub. Serv. Comm'n.*, 252 S.W.2d 885 (Ky. 1952).

[12] *Id.* at 890.

[13] *Id.*

[14] Case No. 2005-00142, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky* (Ky. PSC Sept. 8, 2005).

of a proposal that ultimately costs more than an alternative does not necessarily result in wasteful duplication.[15] All relevant factors must be balanced.[16]

STIPULATION

The Stipulation reflects the agreement of all of the parties to the instant matter and the LG&E matter, addressing all of the issues with the exception of the proposed net metering changes (Riders NMS-1 and NMS-2) and the qualifying facility tariff provisions. The major provisions of the Stipulation as they relate to KU's revenues and rates are as follows:

- KU's revenue will increase by $115.9 million, which reflects a reduction of $54.0 million from KU's filed position, as adjusted.[17]
- The stipulated level of base-rate revenue increase is the result of discrete adjustments to KU's original requested increase as provided in the Stipulation, which provisions are summarized below.
- The agreed-to revenue allocation for KU is set forth in Exhibit 2 to the Stipulation.
- KU commits to a base-rate stay out until July 1, 2025, such that any changes from base rates approved in the instant matter shall not take effect before that

[15] *See Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 390 S.W.2d 168, 175 (Ky. 1965). *See also* Case No. 2005-00089, *Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for the Construction of a 138 kV Electric Transmission Line in Rowan County, Kentucky* (Ky. PSC Aug. 19, 2005).

[16] Case No. 2005-00089, *East Kentucky Power Cooperative, Inc.* (Ky. PSC Aug. 19, 2005), final Order at 6.

[17] *See* KU's Supplemental Responses to Commission Staff's First Request for Information (Staff's First Request) (filed Feb. 26, 2021), Item 56.

date. KU's stay out commitment is subject to certain exceptions that are set forth in the Stipulation.

The Stipulation results in the monthly bill of an average KU residential customer increasing by $8.64, or 7.18 percent.[18] A summary of the adjustments to KU's revenue requirement is as follows:

- Return on Equity. The parties to the Stipulation agreed to a Return on Equity (ROE) of 9.55 percent, applied to capitalization. The result is a revenue requirement reduction of $16.7 million. The Stipulation also provided that the ROE that will apply to KU's recovery under its environmental cost recovery mechanism is 9.35 percent for all environmental compliance plans.
- Depreciation Rates. Instead of using the depreciation rates KU proposed in its application for the Brown 3 generation unit, KU agrees to continue to use its currently approved depreciation rates for ratemaking purposes unless and until changed in later Commission proceedings. The other proposed depreciation rates as filed in KU's application should be approved for ratemaking purposes. This adjustment results in a revenue requirement reduction of $33.0 million. The stipulated depreciation rates are attached as Exhibit 1 to the Stipulation. On May 7, 2021, KU and LG&E subsequently filed a Joint Errata Stipulation Exhibit 1 – Depreciation Rates which corrects the depreciation rates for "AMI Intangible Plt (software)" and "Micro/Fiber" set forth in Stipulation Exhibit 1 based on a 15-year life.

[18] KU's Response to Commission Staff's Post Hearing Request for Information (Staff's Post Hearing Request)(filed May 19, 2021), Item 18.

- Updated Pension and Other Post-Employment Benefits (OPEB) Expenses. The Stipulation reflects KU's agreement to use the updated 2021 pension and OPEB projections as the new test year estimate for purposes of calculating the revenue requirement. The adjustment to update the pension and OPEB expense amounts will result in a revenue requirement reduction of $3.9 million.
- Update Long-Term Debt Rate to Reflect Lower Coupon Rates for New Long-Term Debt in Forecasted Test Year. The parties agree that the coupon rate for new long-term debt included in KU's forecasted test year should be reduced from 3.70 percent to 3.40 percent. This adjustment reduces KU's proposed revenue requirement by $0.4 million.
- Stipulation Summary. The table below reflects the impact of each adjustment included in the Rate Case Stipulation:

KU Increase Requested, as Adjusted[19]	$ 169.9 million
9.55% Return on Equity	(16.7) million
Continue Current Depreciation Rate for Brown 3	(33.0) million
Updated Pension and OPEB Expense	(3.9) million
Update Long-Term Debt Rate	(0.4) million
Total Adjustments to Requested Increase	(54.0) million
Overall Stipulated Increase	$ 115.9 million

The Stipulation also reflects the following terms as agreed to by the parties to this matter.

- KU should recover in base rates its normalized plant outage expenses, as requested in its application. Effective July 1, 2021, KU will not establish any

[19] *See* KU's Supplemental Responses to Staff's First Request (filed Feb. 26, 2021), Item 56.

regulatory assets or liabilities to account for the differences between actual plant outage expenses and those to be embedded in base rates established in this proceeding.

- The proposed AMI project should be approved with stipulations on the recovery of the project and how savings will be calculated.
- KU should be authorized to establish a retirement rider that would recover any remaining net book value and decommissioning costs related to Brown 3. The retirement costs would be recovered on a levelized basis over ten years from the retirement date and include carrying charges of the full weighted average cost of capital (WACC). Collections would be offset by depreciation expense for the retired unit included in base rates.
- The parties to the Stipulation also agreed to the revenue allocation and rate design for KU. The Stipulation provides that the allocations of the increase in annual revenue and the rate design for KU as set forth on the schedule designated Stipulation Exhibit 2 is fair, just and reasonable. The Stipulation also provides that the current Basic Service Charges approved by the Commission in Case No. 2018-00294 for residential electric service should remain unchanged. This agreement also includes a one-year economic relief surcredit of $11.9 million to KU customers.[20]
- As shown in Stipulation Exhibit 5, KU will reduce its proposed monthly LED conversion fees under Rate LS to $3.29. Also as shown in Stipulation Exhibit 5,

[20] Application, paragraph 15. The surcredit includes the remaining fees from the refined coal facility agreements and the remaining unprotected excess accumulated deferred income taxes.

KU will add a new LED offering to Rate LS to replace its current 100W HPS Cobra offering. KU commits to conduct a competitive bidding process for street lighting fixtures every five years and will complete such a competitive bid process prior to KU's filing of the next general adjustment of base rates. KU also commits to have its information technology personnel work with their LFUCG counterparts to explore opportunities to allow streetlight outage notifications from LFUCG to flow more directly through to KU.

- KU agrees to work with its coal-mining customers regarding possible economic development options under KU's existing tariffs. Any such option will ensure that the new rate will provide a contribution to the recovery of fixed costs and will be flexible and time-limited. To the extent any such mutually agreed economic development options require Commission approval, KU commits to seek the necessary approval.
- KU commits to engage in a stakeholder process using its existing Demand-Side Management (DSM) Advisory Committee for its next DSM filing to consider and evaluate Peak-Time Rebates and an on-bill financing program.
- KU's current annual shareholder contributions for low-income assistance will be increased by the same percentage as the overall increase in revenue requirement resulting from this proceeding.

ANALYSIS AND FINDINGS

As discussed above, the Commission's statutory obligation when reviewing a rate application is to determine whether the proposed rates are "fair, just, and reasonable."[21]

[21] KRS 278.030(1).

While numerous intervenors with significant experience in rate proceedings and collectively representing a diverse range of customer interests have participated in this case, the Commission cannot defer to the parties as to what constitutes fair, just and reasonable rates. The Commission must review the record, including the stipulation, and apply our expertise and knowledge to make an independent decision as to the level of rates, including terms and conditions of service as well as rate design, that should be approved.

To satisfy its statutory obligation in this case, the Commission has performed our traditional ratemaking analysis, which consists of reviewing the reasonableness of each revenue and expense adjustment proposed or justified by the record, along with a determination of a fair ROE.

Stipulation

Based upon our review of the Stipulation, the attachments thereto, and the case record, including intervenor testimony, the Commission finds that, with the modifications as discussed below, the Stipulation is reasonable and in the public interest. The Commission finds that the Stipulation was the product of arm's-length negotiations among knowledgeable, capable parties and should be approved as modified. Such approval is based solely on the reasonableness of the Stipulation and does not constitute a precedent on any individual issue.

Stay Out Provision

The Stipulation provides that KU will commit to a base-rate "stay out" until July 1, 2025, such that any changes from base rates approved in the instant matter will not take effect before that date. Stated otherwise, KU may file base-rate applications during 2024, but the proposed base rates should not take effect before July 1, 2025. KU's agreement to not file a base rate application until 2024 so that the proposed base rates will not take effect until on or after July 1, 2025, is subject to the following four exceptions:

1. KU retains the independent right to seek Commission approval to establish deferral accounting for certain categories of expenses that have historically been approved for regulatory asset treatment by the Commission.

2. KU retains the right to seek emergency rate relief under KRS 278.190(2) to avoid a material impairment or damage to its credit or operations.

3. The stay out provision does not apply to the operation of any of KU's cost-recovery surcharge mechanisms and riders at any time during the term of the stay out, including any base-rate roll-ins, which are part of the normal operation of such mechanisms.

4. If a statutory or regulatory change, including but not limited to federal tax reform, affects KU's cost recovery, KU may take any action it deems necessary in its sole discretion, including, but not limited to, seeking rate relief from the Commission.

The Commission finds that this stay out provision and the enumerated exceptions to the stay out are reasonable subject to the following modification: KU should provide the Commission with at least 30 days' notice and formally seek Commission approval to seek emergency rate relief under KRS 278.190(2) or to seek rate relief due to a statutory or regulatory change affecting KU's cost recovery, and the request should be supported by evidence that these triggering events will have a material financial impact on KU's financial position.

AMI

The parties to the Stipulation agreed that KU's request for a CPCN for the AMI project and other AMI-related relief requested in KU's application should be granted. The Stipulation also encompassed the parties' agreement to the ratemaking treatment associated with the implementation and deployment of the AMI project, including using "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 the result that customers will not sustain an increase in the combined revenue requirements associated with implementing the AMI project."[22] The Stipulation further provided that KU will work with Walmart and other interested parties to improve the functionality of customer usage data, including evaluating the potential for implementing Green Button Connect My Data functionality and allowing customers with multiple locations to obtain their usage data through a single download.

Having reviewed the record, the Commission finds that the AMI-related provisions of the Stipulation are reasonable based upon the below discussion, and that our approval is conditioned upon KU obtaining approval from the Federal Energy Regulatory Commission (FERC), if FERC approval is necessary, for the accounting treatment being sought by KU with respect to the proposed accrual of Allowance for Funds Used During Construction (AFUDC) during the AMI implementation period. Within 20 days of the date of this Order, KU should file with the Commission notice whether FERC approval is necessary for the AFUDC accounting treatment and an estimated timeline for requesting and receiving FERC approval.

[22] Stipulation Testimony of Kent W. Blake, (Blake Stipulation Testimony), Exhibit KWB-1 at 11.

The Commission emphasizes that, but for the expectation of savings projected by KU in connection with the full deployment of the AMI project, the CPCN would not have been authorized by this Commission. Our determination that KU satisfied the legal standard to grant a CPCN for the AMI project arises from a finding of need based upon an economic analysis only, and not due to the obsolescence of the existing meters. We note that KU failed to evaluate a scenario in which the AMI deployment is delayed or a scenario in which reactive replacements would be reduced in order to minimize the impact of the undepreciated amounts associated with the existing meters that would be retired early.

As KU's sister entity, LG&E noted a CPCN is not a finding that a utility can recover the construction costs in rates; the Commission will review the reasonableness of the AMI construction costs in a future rate case.[23] Additionally, in approving the CPCN for the proposed AMI systems for KU and its sister entity LG&E, the Commission would like to make clear that this investment presents a significant shift and opportunity for Kentucky's largest utilities. Having an AMI system, particularly one coupled with the numerous "smart grid" investments that KU has or intends to make in the near future, represents a fundamental change for the utility. The Commission cautions KU that we expect the utility to not merely make this investment and miss the boat on all of the offerings this change presents. The Commission expects that, given many of the benefits of AMI represent customer savings, occasionally at the expense of KU earnings, there will be inherent tension as to whether KU is compelled to make offerings beneficial to customers after KU has received the ongoing benefit from the return of and on the AMI investment. The

[23] KU's Response to Commission Staff's Post-Hearing Request (filed May 19, 2021), Item 9.

Commission reminds KU that the only reason the Commission approved this CPCN is the net benefit to customers. Nevertheless, merely meeting the net benefits when additional customer benefits from AMI systems are available would not result in rates that are fair, just and reasonable, nor service that is adequate, efficient and reasonable. To that end, the Commission further finds that additional requirements are necessary to ensure that the benefits of the investment and those proffered by KU are fully and completely captured such that ratepayers will not have any rate impact from the implementation and deployment of the AMI project and that customers receive the full benefit of the capital expended for the public's convenience.

- KU shall file quarterly reports updating the status of the AMI project by detailing the status of the implementation and deployment of the project, adherence to budgets, adherence to timeliness, any significant change orders, number of AMI meters implemented, and number of non-AMI meters removed and retired. The first of these reports shall be filed September 30, 2021.
- KU shall establish clear and sufficient baselines for all benefits including items set forth in Appendix E and affirmatively show that the projected savings can be achieved on an incremental basis. The first filing of this requirement shall be in KU's next base rate case.
- KU shall, for each item set forth in Appendix E, provide detailed plans on how it will achieve the benefits and how it will periodically determine if it is maximizing those benefits. Those periodic reviews shall determine the success and failures for each item to-date, and KU should clearly indicate what progress

it is making to maximize those benefits. The first filing of this requirement shall be June 30, 2022, and annually thereafter.

- KU shall develop and implement a pre-pay program as well as develop DSM programs, including those that specifically target low-income customers. The pre-pay program shall be proposed in KU's next base rate case. The Commission points KU to the final order in Case No. 2019-00277[24] in which the Commission noted the potential for Duke Energy Kentucky, Inc.'s (Duke Kentucky) Peak Time Rebate Pilot Program and stated the following:

> Using AMI metering for more than just billing purposes is something that not only Duke Kentucky, but all utilities should consider to maximize the benefits of smart meters. With AMI meters, programs such as Time of Use rates and prepay programs can be easily added as a rate option. Such rate options contribute to lower peak demand and help avoid costly capital investments or free up power to be sold on the market for additional revenue. The Commission encourages Duke Kentucky to learn from this pilot and modify the program so to maximize the benefit. The Commission further urges Duke Kentucky to study the incentive, or rebate, to ensure that the "carrot" is high enough to encourage behavioral changes that are impactful.[25]

- KU shall, on or before its next base rate case, file with the Commission proposed Electric Vehicle tariffs for home or business charging. The tariff should be cost based, but should incent off-peak electric vehicle charging.

- KU shall create detailed plans for customer engagement of its AMI systems. This should include KU's planned customer engagement before, during and

[24] Case No. 2019-00277, *Electronic Application of Duke Energy Kentucky, Inc. to Amend Its Demand Side Management Programs* (Ky. PSC Apr. 27, 2020).

[25] Case No. 2019-000277, *Duke Energy Kentucky, Inc.* (Ky. PSC Apr. 27, 2020), Order at 14–15.

after AMI deployment, including through the system's end of useful life. This plan shall be filed with the Commission by June 30, 2022, and updated and submitted annually thereafter.

- KU shall create detailed plans on AMI obsolescence and replacement strategies. These plans should identify, at a minimum, risks and solutions to early obsolescence, opportunities for greater cross-system compatibility, and successor technologies, including hardware and software, in order to extend the life of as many portions of the proposed AMI systems as reasonably practical. The initial plan on AMI obsolescence and replacement strategies shall be filed with KU's next base rate case.
- KU shall create detailed plans on identifying outages and how the AMI systems will facilitate notification and communication of information with customers regarding outages. This shall include estimated times of repair. These plans shall include the AMI systems' interaction with KU's other "smart grid" investments, including an outage management system. The initial plan shall be filed with the Commission by June 30, 2022, and updated every other year thereafter.
- In addition to the Stipulation term that KU will work with Walmart and other interested parties to improve the functionality of customer usage data, including evaluating the potential for implementing Green Button Connect My Data functionality and allowing customers with multiple locations to obtain their usage data through a single download, the Commission finds that KU shall also be required to receive certification of its Green Button Connect My Data

offering, to residential and non-residential customers alike. KU shall file with the Commission proof of its Green Button Connect My Data certification by June 30, 2023.

- KU shall create a detailed plan for reducing the frequency and amounts of its tariffed nonrecurring charges resulting from it proposed AMI systems.
- KU shall include detailed discussions in each iteration of its Integrated Resource Plan that explain how it is using the information created by the AMI systems to create additional data or study the remainder of the utility's system. The Commission expects KU will study, at the least, how the information created by the AMI systems can be used to benefit: voltage regulation, power quality, asset management, distribution system investment and utilization, load forecasting (at least at the circuit level, if not more granular), peak reduction (generation, transmission and distribution peaks, both coincident and non-coincident), transmission investment and utilization, and important in this matter, the calculation of all avoided cost categories the Commission indicates we look to use in determining NMS-2 and QF compensation.
- Finally, in its next base rate case KU shall indicate any other intended uses of data created by its proposed AMI systems.

Retired Asset Recovery Rider (RARR)

The Commission finds that, while KU has the discretion to determine when a generation unit should be retired, it is the Commission that is vested with the authority to determine the ratemaking treatment resulting from that retirement decision. Based upon the case record, the Commission finds that the Stipulation provision regarding the RARR is reasonable subject to the clarifying modification that KU has the burden of proof to establish the proper level of the remaining net book value and decommissioning costs associated with the retirement of Brown 3, and the appropriateness of recovering those costs.

ROE

In its application, KU used multiple models to develop its ROE recommendation, including: the Discounted Cash Flow (DCF) model, both the Capital Asset Pricing Model (CAPM) and the Empirical Capital Asset Pricing Model (ECAPM), a risk premium analysis (RP), and an analysis to the expected rates of return for utilities (Expected Earnings).[26] Based upon the results of the analyses, KU recommended an ROE range of 9.4 percent to 10.6 percent with a midpoint of 10.0 percent.[27] KU maintained that a ROE of 10.0 percent is fair, just, and reasonable, given market expectations and the economic requirements necessary to maintain its financial integrity and to support its ongoing capital investment requirements.[28] Intervenors including the Attorney General and KIUC jointly, Walmart, and the DOD/FEA provided direct testimony and were subject to discovery by all parties.

Per Section 2.2A of the Stipulation,[29] all parties agreed that the revenue requirement increase for KU's electric operations will reflect a 9.55 percent ROE as applied to KU's capitalization and capital structure of the proposed electric revenue

[26] Direct Testimony of Adrien M. McKenzie (McKenzie Direct Testimony) at 7.

[27] *Id*. at 7. Note that the ROE results include a floatation cost and company size adjustments.

[28] *Id.*

[29] *See* Blake Stipulation Testimony, Exhibit KWB-1 at 5–6.

requirement increases and subsequently adjusted by KU's updated filings and the capitalization effects of adjustments in the Stipulation.[30] Under the Stipulation, KU's overall base rate electric revenue requirement increase resulting from stipulated adjustments is $115.9 million.[31] The use of an ROE of 9.55 percent reduces KU's original requested revenue requirement by $16.7 million.[32] In addition, a 9.35 percent ROE is applied to KU's environmental cost recovery mechanism for all environmental compliance plans.[33] The following table presents the recommended ROEs from KU and the Intervenors and the methods used to support each parties' recommendations:

Party	Recommendation	Methods
KU	10.00%	DCF, CAPM, ECAPM, RP, Expected Earnings
Attorney General/KIUC[34]	9.00%	DCF, CAPM, RP
Walmart[35]	no higher than 9.725%	Survey of awarded ROEs
Joint Intervenors[36]	9.2%-9.3%	Survey of ROE trends
DOD/FEA[37]	9.30%	DCF, CAPM, RP

Stipulation

[30] *Id.* at 5.

[31] *Id*. at 7.

[32] *Id.*

[33] *Id*. at 6.

[34] *See* Direct Testimony of Richard A. Baudino (filed Mar. 5, 2021) at 37.

[35] *See* Direct Testimony of Lisa V. Perry (Perry Testimony) (filed Mar. 5, 2021) at 13.

[36] *See* Direct Testimony of James Owen (filed Mar. 5, 2021) at 28.

[37] *See* Direct Testimony of Christopher C. Walters (filed Mar. 5, 2021) at 3.

Electric and Gas	**9.55%**
Environ Surcharge	**9.35%**

For the reasons discussed below, the Commission finds that an ROE of 9.55 percent for KU's electric operations is unreasonable and higher than that required by investors in today's economic climate, and that this provision of the Stipulation should be modified. Based on the evidence provided though, the Commission finds that the stipulated 9.35 percent ROE for KU's Environmental Surcharge mechanism is reasonable.

The Commission continues to believe that it is appropriate for utilities to present and the Commission to evaluate multiple methodologies to estimate ROEs, and that it is the Commission's role to analyze the various approaches as presented by the parties. As enumerated in the table above, KU and the parties utilized multiple methods to estimate and support their recommended ROEs, which themselves represent a synthesis of a broader range of parties' ROE estimates. The recommended ROE estimates range from a low of 9.0 percent to a high of 10.0 percent. At the conclusion of settlement discussions, all parties jointly recommended a 9.55 percent ROE for KU's electric operations and 9.35 percent to be applied to the environmental surcharge mechanism.

The Commission notes that the recent regulatory decisions have shown a downward trend. S&P Global Market Intelligence reported that the 2019 average awarded ROE for vertically integrated utilities was 9.73 percent and 9.64 percent for all utilities. For 2020, the average awarded ROEs for vertically integrated utilities was 9.55 percent and 9.39 percent for all utilities.[38] These trends in allowed ROE generally

[38] *See* Perry Testimony, Exhibit LVP-3 at 5.

follow the underlying trends of the financial information used in multiple ROE methodologies, such as risk free and debt rates. In addition, the Commission submits our two most recent fully litigated vertically-integrated rate cases 2019-00271[39] and 2020-00174[40] in which an ROE of 9.25 percent and 9.30 percent were awarded, respectively.

The Commission notes that the rating agencies cite several factors that contribute to lower overall risk for KU, including a constructive regulatory framework, an environmental cost recovery mechanism, pass through fuel cost recovery and purchased power cost recovery riders.[41] However, the Commission recognizes that there are other factors contributing to risk affecting KU than otherwise similar-situated electric utilities. First is increased financial risk. KU's capital spending on new facilities as well as maintenance and repair is significant and anticipated to total approximately $2.3 billion or about 34 percent of its net book value of property, plant and equipment through the 2020-2024 period.[42] Second is KU's increased environmental risk due to its lack of fuel diversity. A significant portion of KU's generation capacity is coal fired and has elevated carbon risk.[43] Third, the economy overall is still in the recovery phase from the effects of

[39] *See* Case No. 2019-00271, *Electronic Application of Duke Energy Kentucky, Inc. for 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief* (Ky. PSC Apr. 27, 2020), final Order at 46.

[40] *See* Case No. 2020-00174, *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* (Ky. PSC Jan. 13, 2021), final Order at 50.

[41] *See* for example KU's Response to the Attorney General and KIUC's First Request for Information (Attorney General and KIUC's First Request)(filed Jan. 22, 2021), Item 104, Attachment 3 at 1, 4, and 5 and Attachment 5 at 3 and 5.

[42] McKenzie Direct Testimony at 14.

[43] KU's Response to the Attorney General and KIUC's First Request (filed Jan. 22, 2021), Item 104, Attachment 3 at 6.

the COVID-19 pandemic. As more people become vaccinated and the economic recovery progresses, it is reasonable to expect the economy to return to more normal employment, interest rate, and inflation levels.

Finally, the Commission views the stipulated four year stay out provision as a significant facet of the Stipulation and a risk factor. Having considered and weighed all the evidence in the record, the Commission finds that the stipulated 9.55 percent ROE significantly overstates the risks that KU faces, and thus overstates the allowed return for investors. Nevertheless, in accordance with the underlying financial data provided in this matter and taking into account the risk noted above, the Commission finds that a 9.425 percent ROE for KU's electric operations is fair, just and reasonable, which results in a revenue requirement decrease of $4.76 million from that proposed in the Stipulation.

Finally, with regard to ROE studies and analyses generally, the Commission cautions all parties against unreasonably removing or ignoring "outlier" data. Analyses should not discount data that is merely "too high" or "too low," especially given the number of actions that can be taken to account or counteract for that data, such as averaging or even conducting multiple alternative methodologies. Although there may be merit in excluding truly outlier data in financial or economic modeling and analyses, result-oriented exclusions of data points that are not beyond the realm of reasonableness are inappropriate. The Commission cautions all parties that ROE analyses that exclude results as merely being "too high" or "too low," without adequate support, will be provided less weight in the Commission's determination of an appropriate return.

Forecasted Legal Fees

When asked to provide details concerning forecasted legal fees, KU refused on the basis that the disaggregated information is attorney work product and protected from disclosure.[44] The Commission recognizes and appreciates KU's right to assert its privilege to not disclose certain details of the legal work performed by its attorneys. However, when a utility seeks to recover an expenditure in its rates, the Commission is obligated to review that expenditure to verify that it is just and reasonable. The information KU claimed is privileged is the exact type of information necessary for the Commission to determine the appropriateness of allowing recovery of the "anticipated" costs. Without an understanding of the matters *and* the expected expense of participating in them, any rate regulator would struggle to determine if the amounts requested to be recovered from customers is reasonable. Ignoring for a moment the anticipated amount of each matter, the Commission effectively has no information available to us to determine whether the matters presented are the type for which the Commission should permit attendant costs to be recovered in rates. For instance, the costs of defending claims of willful or negligent action by a utility or its agents may not necessarily be reasonably recovered from customers, especially in instances where a utility's conduct leads to a judgment against it. KU's "Litigation Matters," for example, contain information that merely states the general categories of the anticipated legal cases or the plaintiffs in ongoing litigation. In fact, KU is the defendant or respondent in all of the matters that indicate a plaintiff. To, at a minimum, identify the claim or cause of action presented by the complaint in each case certainly does not infringe on the items KU cited

[44] KU's Response to Staff's Post-Hearing Request (filed May 19, 2021), Item 14.

(unpersuasively) in support of its objection, such as the opinions, conclusion or legal theories of KU's own counsel.

In this instance, we are unable to determine from the evidence of record the reasonableness of KU's forecasted legal fees. Therefore, the Commission finds that $4.2 million[45] should be disallowed, which results in a revenue requirement reduction of $4.3 million.

Edison Electric Institute (EEI) Dues

As part of its proposed rates in this matter, KU sought recovery of its anticipated EEI dues, net of a reduction identified by EEI that is reflective of "'lobbying and political activities' under section 162(e)" of the Internal Revenue Code (IRC).[46] In determining whether it should exclude or include a test-year amount of EEI dues, KU stated that it did not rely on any studies, but instead "relie[d] upon information provided on the invoices received" from the organization.[47] A letter KU provided from Emily Sanford Fisher, EEI's General Counsel and Corporate Secretary, explained that the amount identified by EEI for "lobbying and political activities" is calculated pursuant to Section 162(e) of the IRC. Section 162(e) of the IRC denies the ability of taxpayers to deduct certain lobbying and political expenditures. Ms. Fisher's letter went on to note than the activities identified by EEI under Section 162(e)'s "lobbying and political activities" categories "captures not only

[45] KU's Response to Commission Staff's Fifth Request for Information (filed Apr. 1, 2021), Item 2.

[46] KU's Response to Attorney General and KIUC's Joint Supplemental Request for Information (filed Feb. 19, 2021), Item 36, Attachment 2.

[47] KU's Response to the Attorney General and KIUC's First Request for Information (filed Jan. 22, 2021), Item 94.

federal lobbying, but also state and grassroots lobbying and political activity."[48] Finally, the letter noted that EEI does not separately account for activities that could be described as "regulatory advocacy, and public relations."[49]

Regulatory advocacy and public relations, in addition to legislative advocacy, are categories of costs incurred by EEI and passed onto KU for which the Commission has explicitly denied recovery from customers.[50] In that matter the Commission noted that KU's "description of regulatory advocacy appears to be a form of lobbying activity, which the Commission has not included for rate-making purposes in previous cases."[51] Based on our experience in this matter, we continue to hold this view.

In furtherance of its request to seek recovery of EEI dues, net of the amount removed pursuant to Section 162(e), KU argued that it "excluded the appropriate amount of unrecoverable dues based on the information provided from EEI, which is the same approach the Commission approved in Case No. 2020-00174 in January 2021." Although the Commission did approve a certain amount of EEI dues as recoverable from customers in Case No. 2020-00174, for the following three reasons, the Commission denies recovery of all test-year EEI dues in this matter. First, as KU should know, it has the affirmative burden of proof in this matter as to whether its proposed rates are fair, just and reasonable. Merely incurring, or expecting to incur, an expense is not itself a sufficient basis for the recovery of that expense from customers in rates that are fair, just and

[48] KU's Response to Attorney General and KIUC's Joint Supplemental Request for Information (filed Feb. 19, 2021), Item 36, Attachment 2.

[49] *Id*.

[50] Case No. 2003-00433, *An Adjustment of the Gas and Electric Rates, Terms, and Conditions of Louisville Gas and Electric Company* (Ky. PSC June 30, 2004), Order at 51

[51] *Id*.

reasonable. If a utility's mere incurrence of a cost deemed it reasonable for recovery, half of the statutory scheme in KRS Chapter 278 would have no need to exist. A focus only on the amount of EEI dues *not* recoverable in rates misses the point. KU's affirmative burden is what level of EEI dues *is* recoverable from customers.

The second and third reasons for the Commission's denial of all EEI dues are related to the first, and both reasons are the result of intervening activities. Had both of the other two activities occurred prior to January 2020, the Commission would have denied all EEI dues for Kentucky Power. The first of these intervening actions is EEI's actual regulatory advocacy before the Commission, including in Kentucky Power's recent matter, Case No. 2020-00174. In two sets of written comments and twice in oral comments, agents of EEI advocated directly to this Commission the organization's interests, concern and suggestions regarding the Commission's implementation of rates pursuant to Senate Bill 100, An Act Related to Net Metering.[52] This case also deals with SB 100.

The letter from Ms. Fisher on behalf of EEI provides more explanation of what is and what is not included in the Section 162(e) adjustment than the Commission has received before. Based on the explanation in the EEI letter, coupled with EEI's actual regulatory advocacy, the Commission finds that EEI is engaging in activity the Commission has previously denied recovery of expenses for and, and for which KU seeks recovery of in this matter. The newly-explained information in Ms. Fisher's letter, including the explanation of what *is not* included in the amount excluded by EEI, is the

[52] *See* Case No. 2020-00174, *Electronic Application of Kentucky Power Company,* November 13, 2020 letter from Philip D. Moeller, Public Comments; April 22, 2021 letter from Shelby A. Linton-Keddie, Public Comments.

third basis for denial of the test-year EEI amount. Without any evidence as to the amounts included in the EEI dues related to the inappropriate activities discussed above, the Commission finds KU has not met its burden of proof as to the reasonableness of recovery of any of the proposed EEI dues. The Commission's determination is not a finding that the remainder of the EEI dues is reasonable. As previously noted, KU has the affirmative burden of proof as to the reasonableness of expenses. Merely identifying a portion of costs incurred that a utility does not seek recovery of does not meet the threshold of reasonableness as to the remainder of expenses. Given their public-facing activities, this is even more so for organizations that require dues. Therefore, the Commission has reduced jurisdictional miscellaneous expenses by $0.4 million,[53] which results in a revenue requirement decrease of $0.5 million.

Other Adjustments to Stipulation

The Commission will reduce the amortization of rate case expense to reflect KU's actual expenses, which results in a revenue requirement reduction of $0.05 million.[54] Finally, the stipulated revenue requirement reduction related to the forecasted long-term debt rate appears to be based on the adjustment recommended by the Attorney General and KIUC's witness Lane Kollen, which used an adjusted rate base instead of capitalization.[55] The Commission finds that the adjustment should be based on capitalization, consistent with the reduction of the ROE, which results in a revenue

[53] Application, Schedule F-1.

[54] *See* KU's Supplemental Responses to Commission Staff's First Request for Information (filed Feb. 24, 2021), Item 14d.

[55] *See* Direct Testimony of Lane Kollen at 103–104.

requirement reduction of $0.07 million.[56] A summary of the Commission's adjustments to the Stipulation are shown in Appendix D.

REVENUE ALLOCATION AND RATE DESIGN

Cost of Service Study (COSS)

In the development of the proposed rates, KU relied on its filed COSS as a guide for both revenue allocation and unit charges. For its COSS, KU applied the loss of load probability (LOLP) methodology. Additionally, KU filed a 12 Coincident Peak (12CP) and a 6 Coincident Peak (6CP) COSS in accordance with the Commission's finding in Case No. 2018-00294 that KU should file an alternative COSS along with the LOLP in the company's next base rate case.[57] A utility's LOLP is the probability that a utility system's total demand will exceed its generation capacity. In Case No. 2018-00294, the Commission noted that it did not explicitly reject the LOLP methodology, but recognized that the LOLP methodology had not been adopted in other regulatory jurisdictions, the probabilities are estimates based upon a proprietary software package, and that the LOLP methodology was novel.[58]

Several intervenors argued against the use of the LOLP as a COSS methodology. According to the Attorney General's expert witness, Glenn A. Watkins, the LOLP methodology is the statistical evaluation of the probability of a utility not being able to meet its load obligation at any point in time given its demand and supply resources. Mr. Watkins maintained that in reality, given the excess capacity within the KU/LG&E

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[56] *See* Appendix C, attached to this Order for the calculation of these adjustments.

[57] Case No. 2018-00294, *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates* (Ky. PSC Apr. 30, 2019) at 19.

[58] *Id*. at 18–19.

combined system,[59] there is no reasonable possibility that load requirements would not be met.[60] Mr. Watkins further argued that the LOLP analysis does not reasonably reflect the manner in which generation costs are incurred as the LOLP method assigns generation-related costs to individual classes and gives no consideration to the manner in which generation resources were planned, designed or installed.[61] Mr. Watkins further questioned whether the LOLP method applied by KU follows the LOLP methodology set forth in the National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manuel and requested that the Commission reject the model.[62]

On behalf of KIUC, Steven J. Baron requested that the Commission reject the LOLP methodology, arguing that LOLP methodology has not been adopted by any other utility regulatory agency.[63] Mr. Baron asserted that the LOLP method relies on a projection of 8,760 hours of load data for each rate class, and therefore the model is overly data intensive and raises reliability issues in light of the fact that the models are projecting up to 18 months in the future.[64] Mr. Baron did not find issue with the 12CP or 6CP COSSs, but suggested that the Commission rely on the 6CP COSS noting that it is a more traditional methodology and reasonably reflects cost causation associated with

[59] To the extent KU and LG&E plan and operate each of their generation systems as a combined system to meet load requirements, the Commission will refer to both companies in this section.

[60] Direct Testimony of Glenn A. Watkins (Watkins Testimony) at 22.

[61] Watkins Testimony at 27.

[62] Watkins Testimony at 27–28. Mr. Watkins also requests that the Commission reject the 6 CP and 12 CP COSS, but at issue here is the LOLP COSS.

[63] Direct Testimony of Stephen J. Baron (Baron Testimony) at 7 and 16.

[64] Baron Testimony at 7 and 15.

the need for generation resources.[65] Mr. Baron noted that although KU's COSS witness, Steven Seelye, recommends adoption of the LOLP study, he also acknowledged that the 6CP methodology is more accurate than the 12CP methodology and the 6CP COSS recognizes the factors which impact the need for generation resources.[66]

Finally, the DOD/FEA's witness, Michael P. Gorman, also objected to the LOLP methodology. Similar to Mr. Baron, Mr. Gorman asserted the model is highly complex, data intensive, and less transparent.[67] Mr. Gorman supported the use of the 6CP method as it ties contributions to the system peak demands in the summer and winter periods that align with KU's demand charges outlined in on-peak and off-peak periods, and base, intermediate, and peak period rates.[68] Mr. Gorman maintained, similar to Mr. Watkins, that the NARUC Electric Utility Cost Allocation Manual casts doubt on the reliability and effectiveness of the use of LOLP methodology as a proper cost of service and rate design methodology.[69]

KU agreed that the 6CP is reasonable but also argued for the LOLP methodology.[70] KU admitted that the LOLP is more complex, but asserted it is a more robust model because LOLP analyzes loads for all hours of the year and thus provides a more accurate reflection of the cost to service each rate class.[71] KU further asserted that both PJM and

[65] Baron Testimony at 7 and 20.

[66] Baron Testimony at 13.

[67] Direct Testimony of Michael P. Gorman at 33.

[68] *Id*.

[69] *Id*. at 34.

[70] Rebuttal Testimony of William Steven Seelye at 101.

[71] *Id*. at 82.

MISO use the loss of load expectation method, which is determined by the timing of LOLP hours for calculating the amount of generation resources needed in their capacity markets.[72]

The Commission recognizes the arguments related to the LOLP methodology but still supports its comments from the 2018 Rate Case. The Commission concludes that LOLP methodology raises significant questions regarding reliability due to the significant quantity of data inputs, most of which are estimated forecasts. In addition, KU submitted a LOLP COSS in its last three rate cases, and during that time, no other regulatory commission has approved such a study.

Based on the foregoing, the Commission finds that the LOLP methodology, and in particular the modified version proposed by KU, is not reasonable for use in allocating production-related expenses. Therefore, KU shall not depend on this study as a guide for revenue allocation and rate design in future rate case filings. KU shall file a cost of service study in its next base rate case that uses a methodology approved by NARUC.

Rate Adjustment

In setting the rates shown in Appendix B, the Commission maintained the basic service charges for each class that was included in the Stipulation. The reduction in KU's stipulated revenue increase as found reasonable herein was allocated to the energy charges of those customer classes for which revenue increases were proposed in the Stipulation, accounting for minor differences due to rounding. The reduction to each class's proposed revenue increase was approximately in proportion to the increase set

[72] *Id*. at 83.

forth in the Stipulation. For KU's average electric residential customer, the average monthly bill will increase $7.92 or 6.58 percent.

NET METERING

As noted above, the Stipulation did not address KU's proposed net metering tariffs, NMS-1 and NMS-2.

Based upon changes in Kentucky law resulting from Senate Bill 100, An Act Related to Net Metering, which took effect on January 1, 2020, KU proposed to close the current net metering service tariff, renamed NMS-1 in this proceeding, to new customers, and established a new tariff, NMS-2. KU, Attorney General/KIUC, KYSIA, Joint Intervenors, and Sierra Club presented evidence, to differing degrees, regarding net metering through written testimony, discovery responses, cross-examination at the formal hearing, and in post-hearing briefs.

As discussed below, the Commission will defer a decision on NMS-1 and NMS-2 so that additional information can be filed into the record regarding the NMS-2 export compensation rate. The Commission notes that KU has already or anticipates spending tens-of-millions of dollars on advanced distribution management solutions (ADMS), Distributed Energy Resource Management Systems (DERMS) (even though the penetration of resources on the KU system is miniscule), SCADA and SCADA-related distribution investments, and Distribution Automation and Volt/Var Optimization, all in addition to the proposed AMI project. A primary purpose of much of this investment is to accommodate a dynamic distribution system, particularly one with increasing penetrations of distributed resources. Additionally, the basis for some of these investments, such as voltage regulation, can be accomplished by other means like distributed resources. To ignore the impact or benefit of these investments, or alternatives to these investments, in determining the NMS-2 export compensation rate is unreasonable. Because that is what KU is doing in this matter, the Commission questions whether additional scrutiny or investigation of KU's investment in "smart grid" technology may be necessary.

NMS-2 Export Compensation Rate

Although KU and some of the Intervenors filed evidence into the record, the Commission is concerned by the insufficient record in this case regarding the appropriate compensation rate for energy supplied to the grid. The record does not offer quantification from KU or from the Intervenors for several compensation rate components that the Commission considers are necessary to adequately compensate NMS-2 customers. As the law clearly requires, following the initiation of this proceeding by KU, it is the Commission's obligation to determine the appropriate compensation rate for net metering.[73] Therefore, the Commission finds that the existing record is insufficient to support a conclusion whether the proposed NMS-2 export compensation rate is fair, just and reasonable.

For example, the record is deficient on generation capacity value and additional analysis regarding the existence and value of avoided generation capacity costs from customer-generators is required. KU did not provide avoided generation capacity cost in the proposed NMS-2 export compensation rate, arguing that KU does not have legally enforceable dispatch rights[74] to renewable distributed generating facilities and, therefore,

[73] KRS 278.466(3).

[74] Direct Testimony of William Seelye (Seelye Direct Testimony) (filed Nov. 25, 2020) at 44.

distributed generation yields no appreciable savings in generation fixed costs.[75] In KU's 2018 integrated resource plan (IRP), they indicated a likely need for capacity, potentially as early as 2026.[76] In this proceeding, when discussing how an avoided capacity value could be calculated, KU indicated that a significant amount of data and analysis would be needed to make such a calculation.[77] Critically, KU did not explain how it could have determined that there is no avoided generation capacity value without a similarly rigorous, data-driven analysis as it has proposed for avoided capacity cost. The Commission notes that the Intervenors did not provide a specific generation capacity value either.

The Commission recently approved a net metering successor rate for Kentucky Power Company (Kentucky Power)[78] that proposed a methodology for calculating generation capacity value. The approved net metering successor rate in that case quantified the following avoided-cost elements: energy, ancillary services, generation capacity, transmission capacity, distribution capacity, carbon cost, and environmental compliance cost. Additionally, Kentucky Power will file specific information pertaining to a job benefit value in the next net metering case filed by the utility.

In the Kentucky Power case, the Commission articulated its desire for more evidence to take under consideration, including testimony, fact evidence, and analysis:

> [A]n intervening party's failure to provide evidence regarding an issue does not equate to a shifting of the burden of proof, nor is it the case that a utility has met its burden of proof when the utility's evidence is the only evidence in the record. When

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[75] Seelye Direct Testimony at 55.

[76] Case No. 2018-00348, *Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company* (filed Oct. 19, 2018), IRP Vol. 1, at 5–38.

[77] KU's Response to Commission Staff's Fourth Request for Information (Staff's Fourth Request) (filed Mar. 12, 2021), Item 4.

[78] Case No. 2020-00174, *Kentucky Power Company,* (Ky. PSC May 14, 2021).

> a utility meets it burden of proof, an intervening party has the opportunity, but not the requirement, to rebut the utility's proof through evidence. When a party does not file certain evidence into a case record, the Commission typically makes note of that in an order to be thorough and avoid the misperception that a party's argument has been omitted. Here, due to the novelty of establishing successor net metering rates, the Commission would have welcomed if the intervening parties had shared their expertise and experience in quantifying certain evidence, but we emphasize that the intervening parties did not have an affirmative obligation to do so.[79]

We reiterate here that, while the Intervenors do not have the burden of proof on the net metering successor rate, the Commission granted the parties' requests for permissive intervention in this proceeding so that they could present issues and develop facts that assist the Commission in rendering its decision.[80] We encourage the parties that were granted permissive intervention to draw upon their expertise to quantify issues they present and facts they develop to assist the Commission to the greatest degree possible.

Because the record is insufficient to support a finding that the NMS-2 export compensation rate is fair, just and reasonable, the Commission finds that a decision regarding NMS-1 and NMS-2 should be deferred to afford the parties the opportunity to develop a thorough, robust record with sufficient evidence to support a finding that KU's proposed Tariff NMS-2 rates are fair, just and reasonable.

The Commission is cognizant that it must issue a decision on this issue on or before September 24, 2021, which is the statutory due date established by KRS 278.190(3), and will timely establish a procedural schedule for investigating NMS-1

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[79] *Id.* at 22.

[80] *See* 807 KAR 5:001, Section 4(11). The Attorney General is the only party with a statutory right to intervene in matters before the Commission in accordance with KRS 367.150(8).

and NMS-2. The procedural schedule will consist of supplemental information requests, supplemental testimony, supplemental rebuttal, and a hearing. Parties are advised to submit supplemental testimony related to avoided energy cost,[81] ancillary services cost, generation capacity cost,[82] transmission capacity cost,[83] distribution capacity cost, carbon cost,[84] environmental compliance cost,[85] and, separately, job benefits as they relate to calculating the NMS-2 export compensation rates.

Status of Net Metering Pending Application

KU presented contradictory arguments regarding the date and circumstances under which NMS-1 would be closed to new customers. In its testimony and abbreviated public notice, KU stated that customers with eligible electric generating facilities who submitted an application for net metering service before the effective date of rates established in this proceeding could take service under NMS-1.[86] However, KU's full notice and proposed tariff stated that customers with an eligible electric generating facility could take service under NMS-1 if the customer executed KU's written application for Interconnection and Net Metering prior to January 1, 2021.[87] KU later clarified that

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[81] *See* Case No. 2018-00348, *LG&E/KU 2018 IRP*, Vol. III p. 17, Table 9, and p. 21.

[82] *See Id.* at Vol. 1, p. 5-16, Figure 5-11, p. 5-20, and p. 6-17, 6-18; and Vol. III, p. 7, Figure 3, and p. 21.

[83] *See Id.* at Vol. 1, p. 5-35, table 5-12, p. 6; and Vol. III, p. 13-15, 16, and 18.

[84] *See Id.* at Vol. 1, p. 5-19, p. 5-22, p. 5-23, Table 5-5, and p. 5-24, Table 5-6; and Vol. III, p. 15, Table 8 and p. 16, Figure 9.

[85] *See Id.* Vol. 1, p. 8-29 through 8-36; and Vol. III, p.8.

[86] Direct Testimony of Robert M. Conroy (Conroy Direct Testimony) at 23, lines 4–11; and Application, Tab 6, Exhibit A at 2.

[87] Application, Tab 6, Exhibit C, at 29. *See also* Application Tab 4, P.S.C. No. 20, Original Sheet No. 57.

customers whose eligible electric generating facilities are in service prior to Commission approval of NMS-2 may take service under Rider NMS-1; customers whose eligible generating facilities are not in service prior to the date that the Commission approves NMS-2 must take service under NMS-2 regardless of their application date.[88]

Some intervenors argued that customers with net metering applications that were pending prior to the effective date of an Order approving NMS-2 should be eligible to take service under NMS-1 or NMS-2, regardless of whether or not the facility was installed and operating by that date.[89]

The express language of KRS 278.466(6) states that customers with an "eligible electric generating facility in service prior to the effective date of the initial net metering order by the commission" are eligible to take service under the tariff in place when "the eligible customer-generator began taking net metering service."

Based on the plain language of KRS 278.466(6), the Commission finds that the eligible generating facility must be in service prior to the effective date of the Commission's approval of NMS-2 in order for the eligible customer-generator to take service under NMS-1. Here, that date is the effective date of the Commission's future Order approving the Rider NMS-1 and Rider NMS-2 compensation rates. However, although the express language of the statute rules in this singular instance, the Commission warns KU about their cavalier language regarding serious rate matters. Seemingly, the public-facing information KU provided on this subject, including testimony and the public notice, was relatively accommodating to potential net metering customers.

[88] KU's Response to KYSIA.'s First Request for Information (filed Jan. 22, 2021), Item 4c.

[89] KYSIA's Post-Hearing Brief (filed May 24, 2021), at 4, 6–8; Joint Intervenors' Post-Hearing Brief (filed May 24, 2021) at 6, 13–16; and Joint Intervenors' Response Brief (filed June 1, 2021) at 15.

For instance, public notices mentioned merely the filing or acceptance of an application for service in order to be provided legacy status. Nevertheless, when questioned on the subject KU's "clarification" was for folks to read the fine print, necessarily cross-referencing the tariff language with multiple statutes. It is the Commission's experience that in cases of this size, public notices and testimony are the two items the general public are most likely to review, and must accurately represent proposed rates and conditions of service.

Net Metering Service Interconnection Guidelines

KU proposed to update its Net Metering Service Interconnection Guidelines (Interconnection Guidelines), stating that interconnected eligible customer generation transforms the distribution system from a one-way delivery mode into a complex two-way network for which electricity flows need to be carefully monitored and balanced and proper system protection applied. KU maintained that the new guidelines reflect issues presented by new technology.[90] KU also maintained that it will propose the same guidelines in Case No. 2020-00302[91] and, if necessary, update the Interconnection Guidelines based on guidance from the Commission.[92]

KYSIA recommended that the Commission consider substantive changes to the Interconnection Guidelines in Case No. 2020-00302 rather than this proceeding. KYSIA

[90] Conroy Direct Testimony at 28, lines 3–10.

[91] Case No. 2020-00302, *Investigation of Interconnection and Net Metering Guidelines* (filed Sept. 24, 2020).

[92] Conroy Direct Testimony at 29, lines 1–7.

stated that doing so would allow for the Interconnection Guidelines to be standardized and aligned across multiple Kentucky utilities.[93]

The Joint Intervenors recommended that the Commission reject the proposed revisions to the interconnection guidelines as being inconsistent with KRS 278.467(2) and (3), which require each utility's interconnection guidelines to conform to the guidelines developed by the Commission.[94]

Having considered the case record, and being otherwise sufficiently advised, the Commission finds that, because the Interconnection Guidelines are applicable to all jurisdictional electric utilities, they must be standardized and aligned across all jurisdictional electric utilities. Addressing them in a case-by-case, piecemeal fashion is antithetical to developing standardized guidelines. For these reasons, the Commission finds that KU's proposed revisions to its Interconnection Guidelines are denied. We further find that KU should present its proposed revisions to the Interconnection Guidelines as issues to be determined in Case No. 2020-00302.

Net Metering Service Application Forms

KU proposed to remove the net metering service application forms from its tariff and to file any future changes to the forms with the Commission in the most recent administrative case concerning net metering guidelines. KU explained that the forms would still be available on their website and that paper versions would be available upon request. KU asserted that removing the forms from the tariff would reduce the size of the

[93] Direct Testimony of Benjamin D. Inskeep, at 25–26, lines 14–2.

[94] Joint Intervenors' Post-Hearing Brief at 17.

tariff and would reflect the fact that customers interested in net metering service are able to fill the forms out online.[95]

The Commission notes that the application forms are one page each, and thus removing them from the tariff would have no significant effect on the size of the tariff. In addition, whether the forms are in the tariff or not, customers could still complete the forms online if they so choose. The Commission concludes that future revisions to the application forms would receive a more thorough review through revisions to the tariff rather than through filing them into the post-case file of an administrative case. For these reasons, the Commission finds that KU's proposal to remove the net metering service application forms from its tariff and to file them with the Commission in the most recent administrative case concerning net metering guidelines should be rejected.

Transferring, Closing, or Creating a New Account

KU indicated that, in circumstances where both persons in a marriage are listed on an account, if they were to divorce and one spouse stayed in the house or one were to pass away and the surviving spouse stayed in the house, the account would then switch exclusively to the then determined primary account holder. If the premises were served under NMS-1 or NMS-2, any accumulated bill credits would be maintained under the exclusive then-determined primary account holder's account. However, if only one spouse's name is listed on the account and the couple divorced with the spouse whose name is not on the account staying in the house, or one spouse passed away and the surviving spouse stayed in the house, seemingly due to internal processes, the old account would be closed and a new one created. When a new account is established

[95] Conroy Direct Testimony at 28, lines 11–22.

under these circumstances and the premises continue to be served under NMS-1 or NMS-2, any accumulated credits would not be transferable or eligible for a cash refund on the closing of the account. KU indicated they use the same process for all rate schedules when transferring, closing, or creating a new account.[96]

The Commission is concerned about the fairness of KU's process for determining when an account should be closed and a new one created. Because this process affects all customers, including those taking service under NMS-1 or NMS-2, the Commission will further investigate this issue during the continuance of this proceeding, and will review the impact of the condition of service on all customers.

MISCELLANEOUS TARIFF ISSUES

Late Payment Charges.

Evidence collected in Case No. 2020-00085[97] challenged the efficiency of late payment charges to certain customers. Therefore, the Commission has recently reviewed utilities' late payment charges during rate cases. In its response to Commission Staff's Second Request for Information in Case No. 2020-00085, KU provided data indicating that the on time pay percentage for residential customers remained fairly steady during the months that the required waiver of late payment charges was in place; however, there was a drop off in the months of October, November, and December 2020.[98]

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[96] KU's Response to Staff's Post-Hearing Request (filed May 19, 2021), Item 28.

[97] Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19.*

[98] Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19.*

The late payment charge is intended to elicit customer behavior; however, KU also claimed that the charge is cost based. KU provided support showing the average cost per residential late payer is $4.60, while the average late payment charge revenue per residential late payer is $4.14.[99] KU asserted that the average cost per residential late payer did not include corporate burdens.[100] To determine the average cost per residential late payer, KU included the cost to print and mail the termination notice and the cost of customer contact. The customer contact component was calculated by determining a direct cost per transaction for all calls handled by customer service representatives and the Interactive Voice Response System (IVR); multiplying that cost by the number of calls related to account/billing inquiries and payment arrangements/credit; and dividing the result by the total number of calls related to account/billing inquiries and payment arrangements/credit handled by customer service representatives and IVR.[101]

While the percentage of residential customers paying on time remained steady for most of the period the late payment charge waiver was in place, the evidence also shows that there was a fairly significant decrease in the number of residential customers paying on time during the months of October through December 2020. Regarding the cost support provided, the Commission is concerned that KU may be overstating the costs, by allocating fixed expenses of the IVR, for instance, and understating the number of contacts related to late payments, particularly by not including any of the 1.2 million customer payment interactions. However, based on the case record, including the

[99] KU's Response to Joint Intervenors' Second Request (filed Feb. 19, 2021), Item 2, at 6.

[100] KU's Response to Staff's Post-Hearing Request (filed May 19, 2021), Item 21, Attachment.

[101] *Id.*

Stipulation provisions agreed to by parties who represent the interests of residential customers, the Commission accepts that the 3 percent residential late payment charge is fairly representative of costs incurred, and thus finds that KU may continue charging the 3 percent residential late payment charge. In KU's next general rate case, the Commission finds that KU should file formal cost support supporting the 3 percent, or another percentage, residential late payment charge.

<u>Residential Time of Day Service</u>

Under KU's Rate RS – Residential Service, if a customer receives a pledge for or notice of low income energy assistance from an authorized agency, they are not assessed or required to pay a late payment charge for the bill for which the pledge or notice is received, nor are they assessed or required to pay a late payment charge in any of the 11 months following receipt of such pledge or notice. This is a positive and beneficial offering, and the Commission commends KU for having and maintaining such a provision. This term of service ensures that customers who already struggle to pay are not placed in a position where, in addition to being unable to pay for service rendered, they are also required to pay ever-increasing late fees that they likely cannot afford. Not waiving a late fee in this instance creates added hardship, does not serve any purpose in incenting appropriate behavior and only creates additional and unrecoverable bad debt expense that is ultimately recovered from other customers.

In reviewing KU's Residential Time of Day (RTOD) tariffs, the Commission notes that those rate schedules do not contain that same provision. The Commission sees no reason why such a provision should not also be applied to residential customers taking service under RTOD-Energy or RTOD-Demand, as those rate schedules do not prohibit someone receiving low-income energy assistance from taking service under the rate schedules. Therefore, the Commission finds that the provision regarding the late payment charge included in Rate RS for residential customers receiving a pledge for or notice of low-income energy assistance from an authorized agency should also be added to KU's RTOD tariffs.

Late Payment Fee Waiver

KU's tariffs currently allow residential customers to request that one late payment fee be waived per year if the customer is in good standing, meaning that they have not been assessed a late payment charge for the previous 11 months. KU proposed to extend the waiver provision to non-residential customers, with the exception of rate schedule Pole and Structure Attachment Charges (PSA). KU witness Saunders stated that KU prefers to give customers the choice of when they want to have their late payment charge waived, under the belief that doing so creates a positive customer experience.[102] However, as later pointed out by KU's witness Robert M. Conroy, if a customer fails to request that a late payment charge be waived upon the first instance, then that customer would have to wait at least 12 months before they could request a waiver, because they would no longer be considered in good standing after being assessed a late payment charge.[103] The waiver provision appears to have been sparsely utilized by KU's residential customers since it went into effect in 2019. KU has not proactively informed customers of the option to have a late payment charge waived. Customers only become aware of that option if they make a call to KU or review KU's tariff.

[102] Hearing Video Transcript (HVT) of the April 26, 2021 Hearing at 15:47:28.

[103] HVT of the April 28, 2021 Hearing at 11:21:50.

With over 430,000 residential customers, only 242 customers took advantage of the waiver option between June 2019 and February 2020.[104] That amounts to approximately 0.06 percent of KU residential customers. The utilization numbers indicate that customers are either unaware of the option to have a late payment charge waived or they do not understand when they can ask for a waiver of the late payment charge. In its post-hearing brief, KU indicated that they will include language regarding the availability of the late payment charge waiver provision in the June 2, 2021 edition of its Powersource newsletter, which is distributed as a bill insert to all residential paper bills and is distributed electronically to customers who receive communications via electronic means. KU also states that they posted new language to its website regarding the availability of the late payment charge waiver.

The Commission finds that adding the late payment waiver provision to non-residential customers, with the exception of those served under rate schedule PSA, is reasonable and that it should be approved as modified below. While the Commission applauds KU's improvement in communicating the availability of the late payment charge waiver to its residential customers, because the customer actually does not have a choice of when to request the late payment fee waiver and the fact that no rational customer eligible for such a waiver would choose to not waive a late payment charge if they knew they would not be able to do so for at least another 12 months, the Commission finds that the late payment charge waiver should be automatic for both residential and non-residential customers if a customer is in good standing.

[104] KU's Response to Staff's Post-Hearing Request (filed May 19, 2021), Item 40.

In its post-hearing brief, KU asserted that changing the late payment charge mechanism to automatic instead of by request would impact the revenue requirement as reflected in the parties' negotiated stipulation. When calculating the revenue requirement in these proceedings, KU indicated that it did not assume any late payment charge waivers and thus did not reduce miscellaneous revenues. It also indicated that it was not seeking regulatory asset treatment for late payment charge waivers that are ultimately granted.[105]

The Commission finds no merit in KU's argument that the revenue requirement should be increased if the waiver is made automatic, because all customers who have the option could choose to exercise it each year anyway, making KU indifferent between the two paths. Because KU had the opportunity to account for late payment charge waivers in its revenue requirements or to request regulatory asset treatment for late payment charge waivers and chose not to do so, the Commission finds that no adjustment should be made to the revenue requirements because of the change of the waiver provision from upon request to automatic.

Resale of Electric Energy

KU's current tariff includes a provision prohibiting customers from reselling electric energy. However, the tariff expressly allows a customer to allocate one's bill to any other person, firm or corporation provided the sum of the allocation does not exceed KU's billing. In Case No. 2018-00261,[106] Duke Kentucky proposed to add language to its tariff

[105] Conroy Direct Testimony at 49, lines 18–22.

[106] Case No. 2018–00261, *Electronic Application of Duke Energy Kentucky, Inc. for Authority to 1) Adjust Natural Gas Rates 2) Approval of a Decoupling Mechanism 3) Approval of New Tariffs 4) And All Other Required Approvals, Waivers, and Relief* (Ky. PSC Mar. 27, 2019), Order at 16–17.

that would have allowed customers to allocate their bills to others as long as such allocations did not exceed Duke Kentucky's billing. Ultimately, the Commission rejected the proposed language finding that it would expressly authorize the allocation of bills by master-metered customers to others without any monitoring of the allocation process by Duke Kentucky. KU stated that they do not have the means of monitoring or verifying the accuracy of such allocations without a meter and that there is no metering that KU could use to bill directly. KU also stated that the administrative cost of monitoring such allocations could be significant.[107]

In Case No. 2020-00375,[108] Duke Kentucky proposed a special contract that would have allowed Skypoint Condominium Owners Association, Inc. (Skypoint) to sub-meter its facility and allocate the bills to the residents. In that contract, Skypoint agreed that it would not charge its tenants receiving natural gas service any more than the pro-rated amount of Duke Kentucky's total monthly natural gas bill. The Commission approved the Agreement with the condition that Duke Kentucky commit to monitor the Skypoint allocations three times per year, twice during the peak season and once during the summer.

In order to maintain consistency and in order to address its concerns expressed in the two Duke Kentucky matters, the Commission will allow the language regarding allocating bills to remain in KU's tariff, if KU commits to monitoring any such allocations three times per year, twice during the winter and once during the summer. If KU will not

[107] KU's Response to Commission Staff's Third Request for Information (filed Feb. 19, 2021), Item 2.

[108] Case No. 2020-00375, *Electronic Tariff Filing of Duke Energy Kentucky, Inc. of a Written Consent of Sub-Metering with Skypoint Condominium Owners Association, Inc.* (Ky. PSC. Feb. 25, 2021).

commit to such monitoring, for the same reason that we denied Duke Kentucky's request, the Commission finds that the language regarding allocation of bills to others is unreasonable and that it should be removed from KU's tariffs. Such language expressly authorizes the allocation of bills by master-metered customers to others without any monitoring of the allocation process by KU. Absent monitoring of the allocation process, those being allocated such bills would have no assurance that their allocated share of the bill is accurate and does not represent a resale of service at a profit.

Outdoor Sports Lighting

The Commission notes that KU's Outdoor Sports Lighting Tariff (Rate OSL) is being utilized sparsely, despite having the largest rate of return per KU's cost of service study. Currently, KU's Rate OSL is limited to 20 customers, with only four customers taking service under it now.[109] Increased participation in Rate OSL could provide a significant benefit to KU's other customers. The Commission finds that KU should develop a plan to market Rate OSL to potential customers and that it should report on such marketing activities in its next general rate case. KU should include in that report the reasons that any potential Rate OSL customer chose another rate schedule over Rate OSL.

Non-Recurring Charges

In Case No. 2020-00141,[110] the Commission found that the calculation of non-recurring charges should be revised because only the marginal costs related to the service should be recovered through special non-recurring charges for service provided

[109] Seelye Direct Testimony at 33, lines 8–9.

[110] Case No. 2020-00141, *Electronic Application of Hyden-Leslie County Water District for an Alternative Rate Adjustment* (Ky. PSC Nov. 6, 2020).

during normal working hours. In reaching that decision, the Commission found that personnel are paid for work during normal business hours regardless of whether they are on a field visit or not, and therefore labor costs included in nonrecurring charges that occur during regular business hours should be eliminated.

As demonstrated by the evidence of record, KU relies on employee and contract labor to perform its non-recurring services.[111] In this proceeding, due to a number of factors, which include the use of contract labor, the amount of labor in the charge, the number of instances the charge was assessed during the test year, the charge being directly requested by the customer, or the charge being a result of unauthorized service, the Commission has chosen not to remove labor from the following charges: returned payment charge, meter test charge, meter pulse charge, and unauthorized connection charge.

Regarding the disconnect/reconnect service charge, the disconnect/reconnect service charge will no longer be charged to customers who have AMI meters capable of remote disconnection and reconnection. Due to the phasing out of disconnect/reconnect charges as AMI meters are deployed and KU's use of employee and contract labor to perform these services, the Commission has chosen not to remove labor from the disconnect/reconnect charge.

Bill Formats

KU corrected the bill format in their proposed tariff to include a line item for taxes and fees as the customer utilized to generate the original proposed bill format was tax

[111] KU's Response to Commission Staff's Second Request (filed Jan. 22, 2021), Item 123.

exempt, causing the taxes and fees line item to not appear.[112] The Commission finds the revised bill format to be reasonable and that it should be approved.

Cogeneration and Small Power Production Qualifying Facilities

As noted above, the Stipulation did not address KU's proposed revisions to its small and large capacity cogeneration and small power production qualifying facilities tariffs (SQF and LQF).

KU proposed to revise its SQF tariff to treat holidays that fall on weekdays as a weekday for purposes of determining on-peak periods. KU asserted that this would align the application of billing under the SQF tariff with its other time-of-day offerings which treat holidays as weekdays.[113] No intervenor objected to this revision.

KU also proposed to revise the definition of hourly avoided energy cost in its LQF tariff to exclude actual fuel expenses that are fixed and non-avoidable. KU maintained that the proposed revision allows KU to exclude fuel related costs that are fixed and non-variable in nature, such as, natural gas transportation fees, fixed rail transportation costs, rail car leasing, and barge fleeting.[114] KU explained that this list is not meant to be all-inclusive and that it may incur additional fuel related costs that meet the revised definition in the tariff.[115] KYSIA objected to this revision, arguing that the open-endedness of the proposed language would render a qualifying facility (QF) contract meaningless as KU

[112] Attachment to KU's Response to Commission Staff's Sixth Request (filed Apr. 20, 2021), Item 3.

[113] KU's Response to Commission Staff's Second Request (filed Jan. 22, 2021), Item 95a.

[114]KU's Response to Commission Staff's Second Request (filed Jan. 22, 2021), Item 95b and KU's Response to Commission Staff's Third Request (filed Feb. 19, 2021), Item 19a.

[115] KU's Response to Commission Staff's Third Request, (filed Feb. 19, 2021) Item 19a.

could contract away compensation due to a QF by executing longer-term agreements that it then characterizes as fixed.[116]

KYSIA made other recommendations regarding the SQF and LQF tariffs, including: (1) the avoided energy costs under SQF and LQF be modified to include hedging values and avoided line losses; (2) the contract term for SQF be extended to a minimum of ten years; (3) capacity compensation should be established for SQF under the same recommended methodology for LQF; (4) the Commission reject KU's proposed revisions to the methodology for establishing energy rates under LQF; (5) the current LQF be modified to state that the current capacity calculation methodology only applies during resource sufficiency as indicated by KU's most recent IRP or related proceedings in which KU proposes to build or otherwise acquire capacity; (6) avoided capacity cost during periods of resource insufficiency should be established based on the costs of a proxy unit defined by the KU's most recent IRP as the next unit addition; and (7) the Commission require KU to establish a term of ten years or more for LQF contracts that involve the sale of capacity.[117]

Based upon the case record and being otherwise sufficiently advised, the Commission concludes that the record is insufficient to support a finding that KU's proposed revisions to SQF and LQF are fair, just and reasonable. Therefore, the Commission finds that a decision regarding SQF and LQF should be deferred to afford the parties the opportunity to develop a thorough, robust record with sufficient evidence to support a finding that KU's proposed SQF and LQF revisions are fair, just and

[116] Direct Testimony of Justin A. Barnes at 13, lines 10–17.

[117] KYSIA's Post-Hearing Memorandum Brief (filed May 24, 2021) at 34–35.

reasonable. The Commission is cognizant that it must issue a decision on this issue on or before September 24, 2021, which is the statutory due date established by KRS 278.190(3), and will timely establish a procedural schedule to investigate this issue.

Legacy Status of General Service and Power Service Customers

In Case No. 2008-00251,[118] KU proposed significant changes to some of its rate schedules, eliminating some while adding new rate schedules and revising eligibility criteria for certain rate schedules. To minimize the impact to customers, KU permitted customers that did not qualify for service under the new availability terms to become legacy customers under the General Service (Rate GS) and Power Service (Rate PS) rate schedules. In Case No. 2012-00221,[119] KU revised the availability provisions of Rate GS and Rate PS to state that legacy customers that elect to take service under another rate schedule for which they qualify could not take service under the rate schedule they had legacy status under again unless and until they met the availability requirements of the rate.

In this proceeding, KU proposed to reduce the number of legacy customers further by removing legacy status for legacy customers who meet the availability requirements of their rate schedules on the date the new rates go into effect from this proceeding. KU proposed to determine whether the legacy customers meet the availability requirements by examining their usage data for the 12 months ending January 31, 2020. KU chose the 12 months ending January 31, 2020, in order to avoid the effects of the COVID-19

[118] Case No. 2008-00251, *Application of Kentucky Utilities Company for an Adjustment of Electric Base Rates* (Ky. PSC Feb. 5, 2009).

[119] Case No. 2012-00221, *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates* (Ky. PSC Dec. 20, 2012).

pandemic on customers' usage data. This would eliminate legacy status for 442 Rate GS customers and 93 Rate PS customers.[120]

Removing legacy status for the affected customers would create the possibility of revenue shifting between Rate GS and Rate PS because rates approved in this proceeding are established based upon, among other things, the number of customers in each rate schedule, but during the stay out period, some of those customers would lose their legacy status and have to change rate classes permanently. This potential for revenue shifting between Rate GS and Rate PS would move the rate classes away from the approved revenue allocation. This would also create frustration and confusion for those customers who lose their legacy status and are forced to switch rate schedules if they fail to meet the eligibility requirements of their current rate schedule in the future. Therefore, the Commission finds that the proposal to remove legacy status from Rate GS and Rate PS legacy customers who meet the eligibility requirements of their current rate schedule is not reasonable and should be rejected.

Warranty Service

KU proposed a Warranty Service for Customer-Owned Exterior Electric Facilities Rider (Rider WT) which provides the terms under which KU would perform billing and collection services for firms providing warranty service to KU's residential customers for the repair or replacement of customer-owned exterior electric facilities serving the customer's residence and connected to KU's distribution facilities. Any firms that choose to provide such warranty service to KU's residential customers would contract with KU for billing and collection services. The contract would establish the specific terms of the

[120] Conroy Direct Testimony at 33–34, lines 12–7.

service. KU would bill the warranty service to those customers that sign up for a warranty service as a separate line item on the customer's bill and would retain a certain percentage of the fee, as agreed upon in the contract. Customer payments would be applied in the following order: (1) amounts owed to KU for current billing period; (2) unpaid balance for electric service provided in prior billing periods; and (3) fees, including any warranty service fees or taxes collected for other entities. A customer's service would not be terminated if the customer did not pay the warranty fee.[121]

While the warranty fee would be listed as a separate line item on bills for those customers that signed up for warranty service, the bill would not specifically state that failure to pay the warranty fee would not result in a termination of the customer's electric service. KU asserted that the marketing plan will state that electric service will not be shut-off for failure to pay the warranty fee. Customers that do not pay the fee would be removed from the warranty program and notified by the firm providing the warranty service.[122]

The Commission finds Rider WT to be reasonable and that it should be approved subject to the modification that KU should add a message to the bills for customers who purchased the warranty service stating that the warranty service is optional, that the warranty company is not the same as KU and is not regulated by the Public Service Commission, and that the customer does not have to pay the warranty service fee to continue receiving regulated services from KU.

OTHER

[121] Conroy Direct Testimony at 47–48, lines 15–19.

[122] KU's Response to Commission Staff's Second Request for Information (filed Jan. 22, 2021), Item 51a.

Southeast Energy Exchange Market (SEEM)

KU is a member of SEEM, an organization of utilities in the Southeast that are not members of organized wholesale markets or Regional Transmission Operators such as PJM or MISO. SEEM is not an organized market but is a mechanism similar to a bulletin board that will inform participants of available transmission capacity 15 minutes into the future. This will facilitate bilateral trading amongst participants. The SEEM proposal is presently before FERC for approval.

KU shall inform the Commission through quarterly filings the status of the FERC proceeding and any changes that are made to the original proposed organization. In these filings, KU shall report any matters in other jurisdictions that require other jurisdictions' approval for activity related to the formation of SEEM. This report should indicate any conditions imposed on SEEM participants pursuant to the matters required. The initial report under this requirement shall be filed with the Commission by September 30, 2021, and shall continue until all SEEM-related regulatory approvals for all SEEM utilities are complete. This filing shall be make in the post-case correspondence file in this matter. In addition, KU shall file, as part of the off-system sales portion of its monthly Fuel Adjustment Clause filings, updates on SEEM activities. This information shall include administrative and legal expenses associated with the FERC proceeding, the costs of SEEM formation and participation and all costs, and revenues related to purchases and sales if SEEM is approved.

Electric Vehicle Charging Stations

Given the proliferation of electric vehicles (EV), KU's interest in owning EV charging equipment and the prolonged stay-out period proposed in the Stipulation, the Commission finds that KU should proactively develop a study regarding the optimal locations for EV charging vis-à-vis KU's distribution and transmission systems. This is not a study of the best commercial locations within KU's service territory for EV stations, taking into account factors like traffic patterns, amount of time parked or visibility. Rather, this is a study that can only be completed by an incumbent utility, used to identify areas of the distribution and transmission system that, with minimal upgrade costs, can best support EV charging. This study shall determine the best EV charging locations from the perspective of efficient utility planning, and should seek approximately 10-20 EV charging locations that represent KU's service territory's "low hanging fruit." This study shall be completed by June 30, 2022. LG&E and KU are approved to defer up to $300,000 on a combined basis for the costs of these studies. The Commission does not expect the expense of this study to exceed that amount, but if necessary, KU may seek additional leave to defer added expense resulting from the study.

Prior to initiating this study, KU shall seek an informal conference or meeting tracking meeting with Commission staff, and shall ensure each party to this case is notified and invited to attend. This meeting will provide KU with an opportunity to ask questions of Commission staff regarding the goals of the study or any concerns it may have. This forum will also give an opportunity to KU to seek input from other parties to this matter on the substance and conclusions of the study.

The Commission has a two-fold concern regarding KU's expansion of EV charging. First, with the utility entering an otherwise economically competitive field of EV charging, it has a knowledge advantage. As mentioned above, no competitor will have near the information the utility has regarding its own electrical systems. This can lead to an unfair competitive advantage. The Commission's second concern on this subject is for retail electric customers' protection. The Commission notes that an investor-owned utility earns its shareholder return on the level of investment in the utility. As such, a utility is economically incentivized to increase that level of investment, in order to maximize shareholder return. As such, ahead of KU's additional investment in EV infrastructure, the Commission cautions the utility against making unreasonable, unnecessary or unfair investments on the EV front. The Commission will continue to review KU's investments and tariffs on this front to ensure customers are not subsidizing KU's foray into a competitive line of business. Nevertheless, the Commission takes KU's words at face value, notably those in their brief discussing minimization of costs and participation in competitive endeavors while being the incumbent utility.[123]

Additionally, with its next rate application, KU shall clearly indicate in testimony where any EV charging stations that it discussed in this proceeding is or will be located and why each site was chosen. Further, KU shall identify any other EV infrastructure it has invested in or EV charging stations for which cost recovery is sought in the test year.

<u>Merger Study</u>

In Case No. 2017-00415[124] the Commission required KU to file an initial report and in Case Nos. 2018-00294 and 2018-00295[125] the Commission required KU to file annual updates on the potential for a merger of the sister entities. KU filed the initial report on

[123] KU's Post-Hearing Brief (filed May 24, 2021) at 24–25.

[124] Case No. 2017-00415, *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 (*Ky. PSC Apr. 4, 2018).

[125] Case No. 2018-00294, *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates* (Ky. PSC Apr. 30, 2019); and Case No. 2018-00295, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates* (Ky. PSC Apr. 30, 2019).

August 8, 2018, and annual updates on March 31, 2020, and March 31, 2021. In each study, KU did not recommend proceeding with the legal merger of LG&E and KU, asserting that LG&E and KU operate as an integrated company, that costs would exceed savings, that there were not be net savings to KU customers, that regulators whose approval is required, other than the Commission, are unlikely to approve if there are rate increases to cover additional costs from merger, and that name change through merger would require additional transactions requiring regulatory approval and additional costs.[126]

The Commission is not convinced that KU conducted an impartial or serious analysis of a potential merger. The study appears to be results oriented, with no affirmative steps taken to obtain more than cursory opinions of potential hurdles to merger. For example, KU does not include an analysis of the duplication of costs to ratepayers and stress on regulators' resources from filing what is effectively two distinct rate cases every few years, although it did include the entirety of the costs of one-time rate cases it believed would be necessary to effectuate a merger to "harmonize" rates and the one-time costs of regulatory approval for the merger. KU's study is indifferent to the impact its legal status has on others, and it ignores the numerous savings its legal merger would create, both to KU's customers and stakeholders.

Finally, on the issue of legal mergers, over the years KU often speaks of the importance of branding as a barrier to merger. The Commission notes that KU has

[126] Case No. 2017-00415, LG&E/KU Merger Study (filed Aug. 8, 2018); Case No. 2018-00294, LG&E/KU 2020 Merger Study Update (filed Mar. 31, 2020), and LG&E/KU 2021 Merger Study Update (filed Mar. 31, 2021); Case No. 2018-00295, LG&E/KU 2020 Merger Study Update (filed Mar. 31, 2020), and LG&E/KU 2021 Merger Study Update (filed Mar. 31, 2021).

successfully rebranded after recent acquisitions, first by E.ON U.S. and then by PPL Corporation. These rebranding efforts have been widespread, and likely at a significant cost. The Commission reminds KU that it is a government-granted monopoly with the exclusive right to furnish electric service within a certified territory. Its status as a monopoly negates any argument that branding plays any role in preventing a merger.

The Commission expects future merger studies to reflect an unbiased review of the benefits and costs of a legal merger, and we further expect KU to address those qualitative risks continually identified as a hurdle to legal merger. Failure on KU's part to perform unbiased reviews of the subject may lead to the Commission using other resources to study the subject on the Commission's behalf, without KU's involvement.

<u>DSM</u>

In Case No. 2017-00441,[127] KU noted that increased customer adoption of energy efficient (EE) measures and declining avoided costs of energy and capacity was occurring making it more difficult for DSM/EE programs to be more cost-effective.[128] At that time, KU had a capacity surplus of approximately 100 MW resulting in an avoided capacity cost of zero. This zero avoided capacity cost was then used as an input for the California tests and resulted in benefit/cost ratios of less than one, indicating that the costs of the programs outweighed the benefits.[129] As a result, KU proposed and was granted approval for a substantial reduction in the DSM/EE program. KU currently avers that the

[127] Case No. 2017-00441, *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* (Ky. PSC Oct. 5, 2018).

[128] *Id.* at 4.

[129] *Id.*at 29.

landscape has changed regarding avoided capacity especially due to the planned retirements of Mill Creek 1, Mill Creek 2, and Brown 3 and additional capacity will be required by 2028.[130] With these capacity needs, the avoided capacity cost will no longer be zero, which will impact the California test results. Therefore the Commission will require KU to begin evaluating possible DSM programs that will add low-cost value and assist in avoiding the high cost of building new generation.

Tax Credits for Carbon Capture

The federal government, through Section 45Q of the IRS Code, provides tax incentives for qualified carbon capture, storage and utilization projects. With a fleet of almost exclusively fossil-fueled generation, KU faces uncertainty with regard to the life expectancy of these units because of the high probability of carbon dioxide and other greenhouse gas limitations. Any decrease in the useful life of these facilities comes with a risk to the ratepayers in the form of higher rates. This is especially true of Trimble County Unit 2, which went into service in 2011. The remaining book value of that unit is significant, as is the remaining book value of units that have had extensive environmental upgrades, much of which has occurred within the last 15 years.

Based on the Commission's concern, we find that KU shall conduct an analysis of the future of LG&E and KU's fossil-fuel generation with particular attention to avenues to reduce undepreciated assets and to protect ratepayers. This shall include an analysis of the 45Q tax incentives and any other approved incentives regarding carbon capture, storage and utilization. This analysis shall be provided in a report to the Commission by

[130] HVT of the April 28, 2021 Hearing at 2:47:53; HVT of the April 27, 2021 Hearing 1:16:52.

November 30, 2021, and should be subsequently updated and provided as part of KU's subsequent Integrated Resource Plans, until further notice.

Waiver of Liability in Tariff

The Commission is concerned about the number of provision in KU's various tariffs limiting KU's liability. The Commission is also concerned that the language used in some of these provisions is overbroad. Therefore, the Commission intends to establish a separate proceeding in which to investigate the reasonableness of the limitations on KU's liability contained in the terms and conditions found in its tariff provisions.

IT IS THEREFORE ORDERED that:

1. The rates and charges proposed by KU are denied.

2. KU's motion for leave to file the Stipulation and the testimonies in support of the Stipulation is granted.

3. The Stipulation (without exhibits), along with the Addendum, attached hereto as Appendix A, are approved with the modifications discussed herein.

4. The rates and charges in Appendix B, attached hereto, are fair, just and reasonable for KU to charge for service rendered on and after July 1, 2021.

5. Within 20 days of the date of this Order, KU shall file notice whether FERC approval of the accounting treatment of AFUDC for AMI deployment is required and, if FERC approval is required, provide the expected timeline for KU to file its requires for FERC approval.

6. Beginning on September 30, 2021, and continuing through the deployment of AMI as set forth in the application, KU shall file quarterly status reports, including the status of the implementation and deployment of the project, adherence to budgets,

adherence to timeliness, any significant change orders, number of AMI implemented, and the number of non-AMI meters removed and retired.

7. KU shall file with its next base rate case a written baseline quantifying all benefits derived from AMI deployment in conformance with the items set forth in Appendix E.

8. Beginning on June 30, 2022, and continuing annually thereafter, KU shall file with the Commission the detailed plans that set forth, for each item listed in Appendix E, how KU will achieve the benefits and how it will periodically determine whether it is maximizing those benefits. Those periodic reviews shall include a determination of the success and failures for each item for each reporting period, and shall clearly indicate what progress KU is making to maximize those benefits.

9. KU shall develop and file with its next base rate case a pre-pay program and DSM programs, including those that target low-income customers.

10. KU shall develop and file on or before its next base rate case an EV tariff for home and business charging that is cost-based and incents off-peak EV charging.

11. KU shall file by June 30, 2022, and continuing annually, a detailed plan for customer engagement of its AMI systems before, during and after AMI deployment, and including through the system's end of useful life.

12. KU shall develop and file with its next base rate case detailed plans on AMI obsolescence and replacement strategies that identify, at a minimum, risks and solutions to early obsolescence, opportunities for greater cross-system compatibility, and successor technologies, including hardware and software, in order to extend the life of as many portions of the proposed AMI systems as reasonably practical.

13. KU shall file by June 30, 2022, and continuing annually, detailed plans regarding how KU identifies outages, how the AMI systems will facilitate notification and communication of information with customers regarding outages, the estimated times of repair, and the AMI systems' interaction with KU's other smart grid investments, including an outage management system.

14. On or before June 30, 2023, KU shall file notice that it obtained certification of its Green Button Connect My Data for residential and non-residential customers.

15. KU shall file with its next base rate case a detailed plan for reducing the frequency and amounts of its tariffed non-recurring charges resulting from it proposed AMI systems.

16. KU shall file in its next IRP, and continuing with each subsequent IRP, a detailed explanation of how KU uses the information created by the AMI systems to create additional data or study the remainder of the utility's system. The explanation shall include KU's analysis of how the information created by the AMI systems can be used to benefit voltage regulation; power quality; asset management; distribution system investment and utilization; load forecasting, at the circuit level and more granular; peak reduction of generation, transmission and distribution peaks, both coincident and non-coincident; transmission investment and utilization; and the calculation of all avoided cost categories used in determining NMS-2 and QF compensation.

17. KU shall file in its next base rate case any other intended uses of data created by its proposed AMI systems not otherwise addressed in ordering paragraphs 15 and 16.

18. KU shall file by September 30, 2021, and continuing quarterly, a report that sets forth the status of the SEEM formation proposal currently pending at FERC, including an changes to the original proposed organization proposed or approved by FERC; any matters in other jurisdictions that require other jurisdictions' approval for activity related to the formation of SEEM; and any conditions imposed on SEEM participants by FERC or other jurisdictions.

19. KU shall file, as part of the off-system sales portion of its monthly Fuel Adjustment Clause filings, updates on SEEM activities, including but not limited to administrative and legal expenses associated with the FERC proceeding, the costs of SEEM formation and participation and all costs, and revenues related to purchases and sales if SEEM is approved.

20. KU shall establish and file by June 30, 2022, a report of a study regarding the optimal locations for EV charging stations in relation to KU's distribution and transmission systems using the criteria set forth in this Order to determine the optimal EV charging locations from the perspective of efficient utility planning.

21. LG&E and KU are authorized to establish a regulatory asset for EV charging station location study costs and shall defer up to $300,000 on a combined basis for the costs of the EV charging station location study. If LG&E and KU's combined costs for the study exceed $300,000, KU may seek additional leave to defer added expense resulting from the study.

22. Prior to initiating the EV charging station location study, KU shall request an informal conference or meeting tracking meeting with Commission Staff to discuss the goals of the study and any concerns that KU may have. KU shall provide notice to and

an invitation for each party to this case to attend the informal conference or meeting tracking meeting.

23. KU shall file in its next base rate case testimony that clearly indicates where any EV charging stations that KU referenced in this proceeding is or will be located and why each site was chosen.

24. KU shall clearly indicate in its next base rate case all EV infrastructure that KU invested in and EV charging stations for which cost recovery is sought in the test year of KU's next base rate case.

25. KU shall file by November 30, 2021, a report of KU's analysis of the future of LG&E and KU's fossil-fuel generation, including but not limited to an analysis of avenues to reduce undepreciated assets to protect ratepayers; 45Q tax incentives; and any other government-approved incentives regarding carbon capture, storage and utilization.

26. The Commission shall defer decisions regarding Tariffs NMS-1, NMS-2, SQF, and LQF to allow the parties to present additional evidence that KU's proposed Tariffs NMS-2, SQF, and LQF are fair, just and reasonable.

27. An eligible generating facility must be in service prior to the effective date of the Commission's approval of Rider NMS-2 in order for the eligible customer-generator to take service under Rider NMS-1.

28. KU's proposed revisions to the Interconnection Guidelines are denied. KU shall file its proposed revisions to the Interconnection Guidelines as issues to be presented and considered in Case No. 2020-00302.

29. KU's proposal to remove the net metering service application forms from its tariff and to file them with the Commission in the most recent administrative case concerning net metering guidelines is denied.

30. KU shall file with its next general rate case formal cost support for the 3 percent, or another percentage, residential late payment charge.

31. KU shall add to its RTOD rate schedules the provision regarding the late payment charge for residential customers receiving a pledge for or notice of low-income energy assistance from an authorized agency.

32. KU's proposal to add the late payment charge waiver provision to its non-residential rate schedules, with the exception of rate schedule PSA, is approved as modified in this Order.

33. KU shall revise its late payment charge waiver provision to allow for the automatic waiver of the charge for eligible customers.

34. Within 20 days of the date of entry of this Order, KU shall file a written statement as to whether it will agree to monitor allocations of bills three times per year, twice during the winter season and once during the summer season. If KU will not commit to this condition, KU shall remove the language regarding allocation of bills to others in the Resale of Electric Energy section of its tariff.

35. KU shall develop and file in its next base rate case a report of KU's plan to market Rate OSL to potential customers including but not limited to marketing activities planned or taken, and the reasons that any potential Rate OSL customer chose another rate schedule over Rate OSL.

36. KU's revised bill format is approved.

37. KU's proposal to remove legacy status from certain customers served under Rate GS and Rate PS is denied.

38. KU's proposed Rider WT is approved with the condition that, for those customers that do sign up for warranty service, KU shall add a message to the billing form of those customers stating that the warranty service is optional, that the warranty company is not the same as KU and is not regulated by the Public Service Commission, and that the customer does not have to pay the warranty service fee to continue receiving regulated services from KU.

39. KU shall not file a LOLP cost of service study in future rate case filings and shall file a NARUC-approved fully embedded cost of service study.

40. KU shall develop and in its next base rate case file testimony regarding a website that provides transparent real-time utilization data for electric vehicle charging stations that is available to the public

41. KU shall develop and in its next base rate case file testimony regarding a website for third party providers that identifies electric vehicle charging locations available to third party providers.

42. Any document filed pursuant to ordering paragraphs 5, 6, 8, 11, 13, 14, 18, 20, 25, and 34 shall be filed in this proceeding's post-case correspondence file.

43. Within 20 days of the date of this Order, KU shall file with the Commission, using the Commission's electronic Tariff Filing System, its revised tariffs as set forth in this Order reflecting that they were approved pursuant to this Order.

44. This case shall remain open pending a final determination regarding NMS-1, NMS-2, SQF, and LQF tariffs.

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By the Commission

ENTERED

JUN 30 2021

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KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Linda C. Bridwell

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00349 DATED JUN 30 2021

THIRTY PAGES TO FOLLOW

STIPULATION AND RECOMMENDATION

This Stipulation and Recommendation ("Stipulation") is entered into this 19th day of April 2021 by and among Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "the Utilities"); 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 Co. ("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"). (Collectively, the Utilities, AG, DoD, KFTC, KIUC, KYSES, KYSEIA, Kroger, LFUCG, Louisville Metro, MA, MHC, Sierra Club, and Walmart are the "Parties.")

W I T N E S S E T H:

WHEREAS, on November 25, 2020, KU filed with the Kentucky Public Service Commission ("Commission") its Application for Authority to Adjust 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, *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* ("KU's Application"), and the Commission has established Case No. 2020-00349 to review KU's Application, in which KU requested a revenue increase of $170.1 million;

WHEREAS, on November 25, 2020, LG&E filed with the Commission its Application for Authority to Adjust 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, *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* ("LG&E's Application") (collectively, KU's Application and LG&E's Application are the "Applications"), and the Commission has established Case No. 2020-00350 to review LG&E's Application, in which LG&E requested a revenue increase for its electric operations of $131.1 million and a revenue increase of $30.0 million for its gas operations (Case Nos. 2020-00349 and 2020-00350 are the "Rate Proceedings");

WHEREAS, the AG, DoD, KFTC, KIUC, KYSES, KYSEIA, Kroger, LFUCG, MA, Sierra Club, and Walmart have participated as full intervenors in Case No. 2020-00349;

WHEREAS, the AG, DoD, KFTC, KIUC, KYSES, KYSEIA, Kroger, Louisville Metro, MHC, Sierra Club, and Walmart have participated as full intervenors in Case No. 2020-00350;

WHEREAS, a remote and in person prehearing informal conference for the purpose of discussing settlement and the text of this Stipulation, attended by representatives of the Parties and the Commission Staff, took place on April 15 and 16, 2021, during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in the Rate Proceedings;

WHEREAS, the Parties hereto unanimously desire to settle all the issues pending before the Commission in the Rate Proceedings except as explicitly noted in Section 5.8 herein;

WHEREAS, it is understood by all Parties hereto that this Stipulation is subject to the approval of the Commission, insofar as it constitutes an agreement by the Parties for settlement, and, absent express agreement stated herein, does not represent agreement on any specific claim, methodology, or theory supporting the appropriateness of any proposed or recommended adjustments to the Utilities' rates, terms, or conditions;

WHEREAS, the Parties have spent many hours over several days to reach the stipulations and agreements which form the basis of this Stipulation;

WHEREAS, all of the Parties, who represent diverse interests and divergent viewpoints, agree that, though certain issues have been reserved for litigation at hearing as set out in Section 5.8, this Stipulation, viewed in its entirety, is a fair, just, and reasonable resolution of their issues resolved in this Stipulation; and

WHEREAS, the Parties believe sufficient and adequate data and information in the record of these proceedings support this Stipulation, and further believe the Commission should approve it without modifications or conditions;

NOW, THEREFORE, for and in consideration of the promises and conditions set forth herein, the Parties hereby stipulate and agree as follows:

ARTICLE I. STAY-OUT COMMITMENT

1.1. Four-Year Stay-Out Commitment. The Utilities commit to a base-rate "stay out" until July 1, 2025, such that any changes from base rates approved in Case Nos. 2020-00349 and 2020-00350 shall not take effect before that date. Therefore, the Utilities may file base-rate applications during 2024, but the proposed base rates shall not take effect before July 1, 2025.

1.2. Stay-Out Exceptions.

(A) Each of LG&E and KU will retain the independent right to seek the approval from the Commission of the deferral of: (1) extraordinary, nonrecurring expenses that could not have been reasonably anticipated or included in the Utilities' planning; (2) expenses resulting from statutory or administrative directives that could not have been reasonably anticipated or included in the Utilities' planning; (3) expenses in relation to government or industry-sponsored initiatives; or (4) extraordinary or nonrecurring expenses that, over time, will result in savings that fully offset the costs.

(B) The Utilities will retain the right to seek emergency rate relief under KRS 278.190(2) to avoid a material impairment or damage to their credit or operations.

(C) The provisions of Section 1.1 shall not apply, directly or indirectly, to the operation of any of the Utilities' cost-recovery surcharge mechanisms and riders at any time during the term of Section 1.1, including any base-rate roll-ins, which are part of the normal operation of such mechanisms.

(D) If a statutory or regulatory change, including but not limited to federal tax reform, affects KU's or LG&E's cost recovery, KU or LG&E may take any action either or both deem necessary in their sole discretion, including, but not limited to, seeking rate relief from the Commission.

ARTICLE II. <u>ELECTRIC REVENUE REQUIREMENTS</u>

2.1. Stipulated Items Used to Adjust Utilities' Electric Revenue Requirements. The Parties stipulate the following adjustments to the annual electric revenue used to determine the base rate increase. For purposes of determining fair, just and reasonable electric rates for LG&E

and KU in the Rate Proceedings the parties stipulate the adjustments below. The overall base rate electric revenue requirement increases resulting from the stipulated adjustments are:

LG&E Electric Operations: $77,300,000; and

KU Operations: $115,900,000.

The Parties stipulate that increases in annual revenues for LG&E electric operations and for KU operations should be effective for service rendered on and after July 1, 2021.

2.2. Items Reflected in Stipulated Electric Revenue Requirement Increases. The Parties agree that the stipulated electric revenue requirement increases described in Section 2.1 were calculated by beginning with the Utilities' electric revenue requirement increases as presented and supported by the Utilities in their Applications ($170.1 million for KU; $131.1 million for LG&E electric) as subsequently adjusted by the Utilities' update filings (reducing the requested revenue increases by $0.2 million for KU and $2.7 million for LG&E) and adjusting them as described in Section 2.2. The Parties ask and recommend the Commission accept these adjustments as reasonable without modification, except for those adjustments, if any, resulting from items included in Section 5.3:

(A) **Return on Equity.** The Parties stipulate a return on equity of 9.55% for the Utilities' electric operations, and the stipulated revenue requirement increases provided above for the Utilities' electric operations reflect that return on equity as applied to the Utilities' capitalizations and capital structures underlying their originally proposed electric revenue requirement increases as subsequently adjusted by the Utilities' update filings and the capitalization effects of the adjustment in Section 2.2 (B). Use of a 9.55% return on equity reduces the Utilities' proposed electric revenue requirement increases by $16.7 million for KU and $11.0 million for LG&E. The Parties agree that, effective as of the first expense month after the

Commission approves this Stipulation, the return on equity that shall apply to the Utilities' recovery under their environmental cost recovery mechanism is 9.35% for all environmental compliance plans.

(B) **Depreciation Rates.** Rather than use the depreciation rates the Utilities proposed in their Applications for Mill Creek 1 and 2 and Brown 3 generation units, the Utilities will continue to use their currently approved depreciation rates for ratemaking purposes unless and until changed in later Commission proceedings. The other proposed depreciation rates as filed in the Utilities' applications shall be approved for ratemaking purposes. This adjustment, which includes the associated impact of all depreciation adjustments on the Utilities' capitalization and the amortization of excess accumulated deferred income taxes, reduces the Utilities' proposed electric revenue requirement increases by $33.0 million for KU and $36.5 million for LG&E. A complete set of agreed depreciation rates for the Utilities is attached as Stipulation Exhibit 1.

(C) **Updated Pension and Other Post-Employment Benefits ("OPEB") Expense.** The Parties agree that the Utilities will use the updated 2021 pension and OPEB projections as the new test year estimate for purposes of calculating the revenue requirement. The adjustment to update the pension and OPEB expense amounts will reduce the Utilities' proposed electric revenue requirement increases by $3.9 million for KU and $3.0 million for LG&E.

(D) **Update Long-Term Debt Rate to Reflect Lower Coupon Rates for New Long-Term Debt in Forecasted Test Year.** The Parties agree that the coupon rate for new long-term debt included in the Utilities' forecasted test year should be reduced from 3.70% to 3.40%. This adjustment reduces the Utilities' proposed electric revenue requirement increases by $0.4 million for KU and $0.6 million for LG&E.

2.3. Summary Calculation of Electric Revenue Requirement Increases. The table below shows the calculation of the stipulated electric revenue requirement increases as adjusted from the revenue requirement increases requested in the Utilities' Applications:

Item	KU ($M)	LG&E Electric ($M)
Filed electric revenue requirement increases as adjusted[1]	169.9	128.4
9.55% return on equity	(16.7)	(11.0)
Continue to use current depreciation rates for MC 1 and 2 and Brown 3	(33.0)	(36.5)
Updated pension and OPEB expense	(3.9)	(3.0)
Updated long-term debt rate	(0.4)	(0.6)
Electric revenue requirement increases after stipulated adjustments	115.9	77.3

ARTICLE III. <u>GAS REVENUE REQUIREMENT</u>

3.1. Stipulated Items Used to Adjust LG&E's Gas Revenue Requirement. The Parties stipulate the following adjustments to the annual gas revenue requirement used to determine the base rate increase. For purposes of determining fair, just, and reasonable gas rates the Parties stipulate the adjustments below. Effective for service rendered on and after July 1, 2021, the stipulated adjustments result in an increase in annual base rate revenues for LG&E gas operations of $24,200,000.

[1] *See* KU's and LG&E's Updated Responses to PSC 1-56 dated Feb. 26, 2021; KU Schedule M-2.1; LG&E Schedule M-2.1-E. The "Filed electric revenue requirement increases as adjusted" values shown in the table result from subtracting the updated revenue requirement increase differences shown in KU's and LG&E's Updated Responses to PSC 1-56 from the unadjusted total revenue requirement increases shown in KU Schedule M-2.1 and LG&E Schedule M-2.1-E.

3.2. Items Reflected in Stipulated Gas Revenue Requirement Increase. The Parties agree that the stipulated gas revenue requirement increase described in Section 3.1 was calculated by beginning with LG&E's gas revenue requirement increase as presented and supported by LG&E in its Application ($30.0 million) as subsequently adjusted by LG&E's update filing (increasing the requested revenue requirement by $3.0 million) and adjusting the proposed gas revenue requirement increase as described in this Section 3.2. The Parties ask and recommend that the Commission accept these adjustments as reasonable without modification, except for those adjustments, if any, resulting from items included in Section 5.3.

(A) **Return on Equity.** The Parties stipulate to a return on equity of 9.55% for LG&E's gas operations, and the stipulated revenue requirement increase for LG&E's gas operations reflects that return on equity as applied to LG&E's gas capitalization and capital structure underlying its originally proposed gas revenue requirement increase. Use of a 9.55% return on equity reduces LG&E's proposed gas revenue requirement increase by $3.4 million. The Parties agree that, effective as of the first expense month after the Commission approves this Stipulation, the return on equity that shall apply to the Utilities' recovery under their gas line tracker (GLT) mechanism is 9.35% for all capital expenditures recovered therein.

(B) **Updated Pension Expense.** The Parties agree that LG&E will use the updated 2021 pension and OPEB projections as the new test year estimate for purposes of calculating the revenue requirement. The adjustment to update the pension and OPEB expense amounts will reduce LG&E's proposed gas revenue requirement increase by $1.0 million.

(C) **Update Long-Term Debt Rate to Reflect Lower Coupon Rates for New Long-Term Debt in Forecasted Test Year.** The Parties agree that the coupon rate for new long-term debt included in the Utilities' forecasted test year should be reduced from 3.70% to 3.40%.

This adjustment reduces the proposed revenue requirement increase for LG&E's gas operations by $0.2 million.

(D) **Inline Inspection Normalization Adjustment.** The Parties agree that inline inspection expenses included in the forecasted test year for LG&E's gas operations should be reduced to a 2021-2025 normalized level. This adjustment reduces the proposed revenue requirement increase for LG&E's gas operations by $4.2 million.

3.3. Summary Calculation of Gas Revenue Requirement Increase. The table below shows the calculation of the stipulated gas revenue requirement increase as adjusted from the revenue requirement increase requested in LG&E's Application:

Item	LG&E Gas ($M)
Filed gas revenue requirement increase as adjusted[2]	33.0
9.55% return on equity	(3.4)
Updated pension expense	(1.0)
Updated long-term debt rate	(0.2)
Gas inline inspection expense normalization	(4.2)
Gas revenue requirement increase after stipulated adjustments	24.2

ARTICLE IV. REVENUE ALLOCATION AND RATE DESIGN

4.1. Revenue Allocation and Rate Design. The Parties hereto agree that the allocations of the increases in annual revenues and the rate design for KU and LG&E electric operations, as well as the allocation of the increase in annual revenue and the rate design for LG&E

[2] *See* LG&E's Updated Response to PSC 1-56 dated Feb. 26, 2021; LG&E Schedule M-2.1-G. The value shown in the table results from subtracting the updated revenue requirement increase difference shown in LG&E's Updated Response to PSC 1-56 from the unadjusted total revenue requirement increase shown in LG&E Schedule M-2.1-G.

gas operations, as set forth on the schedules designated Stipulation Exhibit 2 (KU), Stipulation Exhibit 3 (LG&E electric), and Stipulation Exhibit 4 (LG&E gas) attached hereto, are fair, just, and reasonable.

4.2. Tariff Sheets. The Parties hereto recommend to the Commission that, effective July 1, 2021, the Utilities shall implement the electric and gas rates set forth on the tariff sheets in Stipulation Exhibit 5 (KU), Stipulation Exhibit 6 (LG&E electric), and Stipulation Exhibit 7 (LG&E gas) attached hereto, excepting only the issues to be addressed at hearing set out in Section 5.8 below.

4.3. Residential Basic Service Charges to Remain at Current Levels. The Parties agree that the current Basic Service Charges approved by the Commission in Case Nos. 2018-00294 and 2018-00295 for residential gas and electric service shall remain unchanged.

ARTICLE V. TREATMENT OF CERTAIN SPECIFIC ISSUES

5.1. Scheduled Plant Outage Expense Adjustment. The Parties agree to use the Utilities' normalized level of plant outage expenses as filed effective with the change in base rates on July 1, 2021. Effective July 1, 2021, the Utilities 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.

5.2. Advanced Metering Infrastructure ("AMI") Ratemaking. The Parties agree to the following ratemaking-related items regarding the Utilities' proposed AMI deployment:

(A) The Utilities will record their investment in the AMI project as Construction Work In Progress ("CWIP") and accrue an allowance for funds used during construction ("AFUDC") during the implementation period, currently projected to be approximately 5 years.

(B) The Utilities will record a regulatory liability until their first base rate proceedings following AMI implementation or other proceedings to address the AMI revenue requirement following AMI implementation to the extent their actual meter reading and field service expenses are less than the forecast test period level embedded into base rates during these current proceedings. The Utilities also will include in this regulatory liability, until their first base rate proceedings following AMI implementation or other proceedings to address the AMI revenue requirement following AMI implementation, the cost of capital effect during the implementation period for the reduction in net book value and increase in accumulated deferred income taxes for meters replaced and retired during the AMI implementation. The Utilities commit to keep detailed records to document the savings created by AMI that will be recorded in the regulatory liability.

(C) The Utilities will record a regulatory asset during the AMI implementation period comprising three components: (1) operating expenses associated with the project implementation; (2) the remaining net book value of electric meters replaced and retired as part of this project less any excess depreciation recovered in base revenues after the electric meters are replaced and retired; and (3) the difference between AFUDC accrued at the Utilities' weighted average cost of capital and that calculated using the methodology approved by the Federal Energy Regulatory Commission.

(D) For tax purposes, depreciation will begin as the AMI meters, network and systems are put into service at interim dates during the implementation period. Book depreciation expense will be recorded when the entire project is placed in service for the benefit of customers.

(E) The Utilities will seek AMI cost recovery in the first base rate case proceedings following AMI implementation if necessary; otherwise, if no base rate adjustment is required, the Utilities will make a separate filing to address the AMI revenue requirement impact and set the amortization periods for associated regulatory assets and liabilities following AMI implementation. The Parties agree it is reasonable to amortize the AMI-related depreciation of the capital and initial software/networking assets, including meters, over a 15-year period.

(F) The Utilities will maintain current data use and customer service disconnection policies, and will address possible changes to such policies, if any, in their first base rate case proceedings following AMI implementation or other proceedings to address the AMI revenue requirement following the implementation of the AMI project.

(G) The Utilities 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 the result that customers will not sustain an increase in the combined revenue requirements associated with implementing the AMI project.

(H) The Parties recognize and agree that in approving this AMI ratemaking proposal the Commission is not foregoing its authority to review the costs, regulatory assets, and regulatory liabilities for ratemaking purposes in future base rate cases or other regulatory proceedings.

(I) The Parties agree that the Utilities' requested AMI-related certificates of public convenience and necessity and other AMI-related relief requested in the Utilities' Applications should be granted.

(J) The Utilities agree to work with Walmart and other interested Parties to improve the functionality of customer usage data, including evaluating the potential for (i) implementing Green Button Connect My Data functionality and (ii) allowing customers with multiple locations to obtain their usage data through a single download.

5.3. Electric Plant Retirements and Retirement Rider. The Parties agree that the Utilities remain responsible for retirement decisions regarding electric plant, and in particular regarding electric generating units and stations. Also, the Parties recognize that using depreciation rates as agreed in this Stipulation for Mill Creek Unit 1, Mill Creek Unit 2, and E.W. Brown Unit 3 could result in significant remaining net book value and uncollected decommissioning costs for these generating assets retired after the date of this Stipulation. Therefore, the Utilities shall be authorized to recover the Retirement Costs of such retired assets and other site-related assets that will not continue in use through a Retired Asset Recovery Rider (attached hereto as Stipulation Exhibits 8 (KU) and 9 (LG&E)) until the Retirement Costs are fully recovered. "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.

(A) The Retirement Costs exclusive of ADIT are to be recorded as regulatory assets. The Retirement Costs inclusive of ADIT shall be recovered on a levelized basis, including a weighted average cost of capital carrying cost using the most recently approved base rate return on equity. The recovery period for each retired generating unit shall be ten years from the retirement date of the unit.

(B) The Retired Asset Recovery Rider will include a credit for the depreciation expense and rate of return component for each retired unit embedded in base rates at that time, but no credit for any other expense embedded in base rates.

(C) The Utilities will use best efforts to minimize the cost of dismantling and to maximize salvage credits.

(D) The Retired Asset Recovery Rider will use the Group 1 and Group 2 methodology for revenue allocation used in the Utilities' Environmental Cost Recovery Surcharges.

5.4. Lighting Issues.

(A) As shown in Stipulation Exhibit 6 (LG&E electric), LG&E will implement a one-time LED conversion fee of $260.00 under Rate LS rather than the filed one-time conversion fee of $277.29. This lower conversion fee, along with the stipulated LG&E LS & RLS rates, is expected to support Louisville Metro to reach its goal of converting all non-LED fixtures to LED fixtures over a multi-year period, subject to negotiations between LG&E and Louisville Metro regarding the number of fixture conversions per year.

(B) As shown in Stipulation Exhibit 5 (KU) and Stipulation Exhibit 6 (LG&E electric), the Utilities will reduce their proposed monthly LED conversion fees under Rate LS to $3.29 for KU and $4.62 LG&E.

(C) As shown in Stipulation Exhibit 5 (KU) and Stipulation Exhibit 6 (LG&E electric), the Utilities will add a new LED offering to Rate LS to replace their current 100W HPS Cobra offering.

(D) The Utilities commit to conduct a competitive bidding process for street lighting fixtures every five years and will complete such a competitive bid process prior to the Utilities' filing of the next general adjustment of base rates.

(E) The Utilities commit to have their information technology personnel work with their LFUCG and Louisville Metro counterparts to explore opportunities to allow streetlight outage notifications from LFUCG and Louisville Metro to flow more directly through to the Utilities.

5.5. Coal Mining Economic Development Options. The Utilities agree to work with their coal-mining customers regarding possible economic development options under the Utilities' existing tariffs. Any such option will ensure that the new rate will provide a contribution to the recovery of fixed costs and will be flexible and time-limited. To the extent any such mutually agreed economic development options require Commission approval, the Utilities commit to seek the necessary approval.

5.6. Stakeholder Process to Consider Peak-Time Rebates and an On-Bill Financing Program. The Utilities commit to engage in a stakeholder process using the Utilities' existing DSM Advisory Committee for their next DSM filings to consider and evaluate Peak-Time Rebates and an on-bill financing program.

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.

5.8. Issues Explicitly Not Addressed by this Stipulation and to Be Addressed at Hearing. The Parties agree that the Utilities' net metering proposals (Riders NMS-1 and NMS-2) and qualifying facility tariff provisions (Riders SQF and LQF) are not addressed by this Stipulation and may be addressed by any or all Parties at hearing in these proceedings. Because these issues are to be addressed at hearing, the related electric tariff sheets (Sheet Nos. 55-55.3, 56-56.1, 57, 58, and 108-108.5) are not included in Stipulation Exhibit Nos. 5 and 6.

5.9. All Other Relief Requested by Utilities to Be Approved as Filed. 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.

ARTICLE VI. MISCELLANEOUS PROVISIONS

6.1. Except as specifically stated otherwise in this Stipulation, entering into this Stipulation shall not be deemed in any respect to constitute an admission by any of the Parties that any computation, formula, allegation, assertion or contention made by any other party in these Rate Proceedings is true or valid.

6.2. The Parties agree that the foregoing Stipulation represents a fair, just, and reasonable resolution of the issues addressed herein and request that the Commission approve the Stipulation.

6.3. Following the execution of this Stipulation, the Parties shall cause the Stipulation to be filed with the Commission on or about April 19, 2021, together with a request to the Commission for consideration and approval of this Stipulation for rates to become effective for service rendered on and after July 1, 2021.

6.4. This Stipulation is subject to the acceptance of, and approval by, the Commission. The Parties agree to act in good faith and to use their best efforts to recommend to the Commission that this Stipulation be accepted and approved. The Parties commit to notify immediately any other Party of any perceived violation of this provision so the Party may have an opportunity to cure any perceived violation, and all Parties commit to work in good faith to address and remedy promptly any such perceived violation. In all events, counsel for all Parties will represent to the Commission that the Stipulation is a fair, just, and reasonable means of resolving all issues in these proceedings that are the subject of this Stipulation and will clearly and definitively ask the Commission to accept and approve the Stipulation as such.

6.5. If the Commission issues an order adopting this Stipulation in its entirety and without additional conditions, each of the Parties agrees that it shall file neither an application for rehearing with the Commission, nor an appeal to the Franklin Circuit Court with respect to such order.

6.6. If the Commission does not accept and approve this Stipulation in its entirety, then any adversely affected Party may withdraw from the Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. If any Party timely seeks rehearing of or appeals the Commission's order, all Parties will continue to have the right to withdraw until the conclusion of all rehearings and appeals. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearings and appeals, all Parties that have not withdrawn will continue to be bound by the terms of the Stipulation as modified by the Commission's order.

6.7. If the Stipulation is voided or vacated for any reason after the Commission has approved the Stipulation, none of the Parties will be bound by the Stipulation.

6.8. The Stipulation shall in no way be deemed to affect or diminish the jurisdiction of the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

6.9. The Stipulation shall inure to the benefit of and be binding upon the Parties hereto and their successors and assigns.

6.10. The Stipulation constitutes the complete agreement and understanding among the Parties, and any and all oral statements, representations, or agreements made prior hereto or contemporaneously herewith shall be null and void and shall be deemed to have been merged into the Stipulation.

6.11. The Parties agree that, for the purpose of the Stipulation only, the terms are based upon the independent analysis of the Parties to reflect a fair, just, and reasonable resolution of the issues herein and are the product of compromise and negotiation.

6.12. The Parties agree that neither the Stipulation nor any of its terms shall be admissible in any court or commission except insofar as such court or commission is addressing litigation arising out of the implementation of the terms herein, the approval of this Stipulation, or a Party's compliance with this Stipulation. This Stipulation shall not have any precedential value in this or any other jurisdiction.

6.13. The signatories hereto warrant that they have appropriately informed, advised, and consulted their respective Parties in regard to the contents and significance of this Stipulation and based upon the foregoing are authorized to execute this Stipulation on behalf of their respective Parties.

6.14. The Parties agree that this Stipulation is a product of negotiation among all Parties hereto, and no provision of this Stipulation shall be strictly construed in favor of or against any Party. Notwithstanding anything contained in the Stipulation, the Parties recognize and agree that the effects, if any, of any future events upon the operating income of the Utilities are unknown and this Stipulation shall be implemented as written.

6.15. The Parties agree that this Stipulation may be executed in multiple counterparts.

[Signature Pages Follow]

APPENDIX A: LIST OF STIPULATION EXHIBITS

Stipulation Exhibit 1:	Depreciation rates for KU and LG&E
Stipulation Exhibit 2:	KU Electric Revenue Allocation and Rate Design Schedules
Stipulation Exhibit 3:	LG&E Electric Revenue Allocation and Rate Design Schedules
Stipulation Exhibit 4:	LG&E Gas Revenue Allocation and Rate Design Schedules
Stipulation Exhibit 5:	KU Tariff Sheets (except Sheet Nos. 55-55.3, 56-56.1, 57, 58, and 108-108.5)
Stipulation Exhibit 6:	LG&E Electric Tariff Sheets (except Sheet Nos. 55-55.3, 56-56.1, 57, 58, and 108-108.5)
Stipulation Exhibit 7:	LG&E Gas Tariff Sheets
Stipulation Exhibit 8:	KU Retired Asset Recovery Rider (Rider RAR)
Stipulation Exhibit 9:	LG&E Retired Asset Recovery Rider (Rider RAR)

IN WITNESS WHEREOF, the Parties have hereunto affixed their signatures.

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

By: ______________________________
Kendrick R. Riggs

-and-

By: ______________________________
Allyson K. Sturgeon

Attorney General for the Commonwealth of Kentucky, by and through the Office of Rate Intervention

HAVE SEEN AND AGREED:

By: John G. Horne II

Lawrence W. Cook
J. Michael West
Angela M. Goad
John G. Horne II

United States Department of Defense and All Other Federal Executive Agencies

HAVE SEEN AND AGREED:

By: ______________________________

Emily W. Medlyn

G. Houston Parrish

Kentucky Industrial Utility Customers, Inc.

REVIEWED AND AGREED:

By: ______________________

Michael L. Kurtz
Kurt J. Boehm
Jody Kyler Cohn

Kentuckians for the Commonwealth,
Kentucky Solar Energy Society,
Mountain Association, and
Metropolitan Housing Coalition

HAVE SEEN AND AGREED:

By: __________________________
Tom FitzGerald

Kentucky Solar Industries Association, Inc.

HAVE SEEN AND AGREED:

By: ______________________

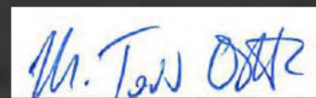
Randal A. Strobo
Clay A. Barkley
David E. Spenard

The Kroger Co.

HAVE SEEN AND AGREED:

By: Robert C. Moore

Robert C. Moore



mes W. Gardner

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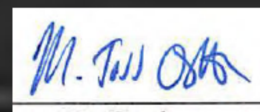

Sierra Club

HAVE SEEN AND AGREED:

By: ____

Joe F. Childers

Matthew E. Miller

Walmart Inc.

HAVE SEEN AND AGREED:

By: ______________________________

Don C.A. Parker
Carrie H. Grundmann
Barry N. Naum

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00349 DATED JUN 30 2021

The following rates and charges are prescribed for the customers in the area served by Kentucky Utilities Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

SCHEDULE RS
RESIDENTIAL SERVICE

Basic Service Charge per Day	$ 0.53
Energy Charge per kWh	
Infrastructure	$ 0.06527
Variable	$ 0.03200
Total	$ 0.09727

SCHEDULE RTOD-ENERGY
RESIDENTIAL TIME-OF-DAY ENERGY SERVICE

Basic Service Charge per Day	$ 0.53
Energy Charge per kWh	
Off-Peak Hours - Infrastructure	$ 0.03227
Off-Peak Hours - Variable	$ 0.03200
Total	$ 0.06427
On-Peak Hours (Infrastructure)	$ 0.18441
On-Peak Hours (Variable)	$ 0.03200
Total	$ 0.21641

SCHEDULE RTOD-DEMAND
RESIDENTIAL TIME-OF-DAY DEMAND SERVICE

Basic Service Charge per Day	$ 0.53
Energy Charge per kWh	
Infrastructure	$ 0.01276
Variable	$ 0.03200
Total	$ 0.04476
Demand Charge per kW	
Base Hours	$ 3.90
Peak Hours	$ 10.10

SCHEDULE VFD
VOLUNTEER FIRE DEPARTMENT

Basic Service Charge per day	$ 0.53
Energy Charge per kWh	
Infrastructure	$ 0.06527
Variable	$ 0.03200
Total	$ 0.09727

SCHEDULE GS
GENERAL SERVICE RATE

Basic Service Charge per Day	
Single Phase	$ 1.35
Three Phase	$ 2.15
Energy charge per kWh	
Infrastructure	$ 0.08632
Variable	$ 0.03253
Total	$ 0.11885

SCHEDULE GTOD-ENERGY
GENERAL TIME-OF-DAY ENERGY SERVICE

Basic Service Charge per Day	
Single Phase	$ 1.35
Three Phase	$ 2.15
Energy Charge per kWh	
Off-Peak Hours - Infrastructure	$ 0.04789
Off-Peak Hours - Variable	$ 0.03253
Total	$ 0.08042
On-Peak Hours (Infrastructure)	$ 0.26491
On-Peak Hours (Variable)	$ 0.03253
Total	$ 0.29744

SCHEDULE GTOD-DEMAND
GENERAL TIME-OF-DAY DEMAND SERVICE

Basic Service Charge per Day	
Single Phase	$ 1.35
Three Phase	$ 2.15
Energy Charge per kWh	
Infrastructure	$ 0.03624
Variable	$ 0.03253
Total	$ 0.06877
Demand Charge per kW	

Base Hours	$ 5.47
Peak Hours	$ 14.16

SCHEDULE AES
ALL ELECTRIC SCHOOL

Basic Service Charge per Day	
Single Phase	$ 2.80
Three Phase	$ 4.60
Energy charge per kWh	
Infrastructure	$ 0.06441
Variable	$ 0.03223
Total	$ 0.09664

SCHEDULE PS
POWER SERVICE

Secondary Service:	
Basic Service Charge per Day	$ 2.96
Demand Charge per kW:	
Summer Rate	$ 25.20
Winter Rate	$ 22.57
Energy Charge per kWh	$ 0.03248
Primary Service:	
Basic Service Charge per Day	$ 7.89
Demand Charge per kW:	
Summer Rate	$ 25.17
Winter Rate	$ 22.59
Energy Charge per kWh	$ 0.03214

SCHEDULE TODS
TIME-OF-DAY SECONDARY SERVICE

Basic Service Charge per Day	$ 7.32
Maximum Load Charge per kVa:	
Base Demand Period	$ 3.25
Intermediate Demand Period	$ 6.64
Peak Demand Period	$ 8.26
Energy Charge per kWh	$ 0.02909

SCHEDULE TODP
TIME-OF-DAY PRIMARY SERVICE

Basic Service Charge per Day	$ 10.77
Maximum Load Charge per kVA:	

Base Demand Period	$ 2.79
Intermediate Demand Period	$ 7.35
Peak Demand Period	$ 9.15
Energy Charge per kWh	$ 0.02573

SCHEDULE RTS
RETAIL TRANSMISSION SERVICE

Basic Service Charge per Day	$ 49.28
Maximum Load Charge per kVA:	
Base Demand Period	$ 2.16
Intermediate Demand Period	$ 7.16
Peak Demand Period	$ 8.91
Energy Charge per kWh	$ 0.02513

SCHEDULE FLS
FLUCTUATING LOAD SERVICE

Primary:

Basic Service Charge per Day	$ 10.77
Maximum Load Charge per kVA:	
Base Demand Period	$ 2.93
Intermediate Demand Period	$ 6.48
Peak Demand Period	$ 8.19
Energy Charge per kWh	$ 0.03128

Transmission:

Basic Service Charge per Day	$ 49.28
Maximum Load Charge per kVA:	
Base Demand Period	$ 1.49
Intermediate Demand Period	$ 2.74
Peak Demand Period	$ 3.76
Energy Charge per kWh	$ 0.03051

SCHEDULE LS
LIGHTING SERVICE

Rate per Light per Month: (Lumens Approximate)

Overhead:

	Fixture Only
Light Emitting Diode	
6,000 – 8,200 Lumens – Cobra Head	$ 9.36
13,000 – 16,500 Lumens – Cobra Head	$ 11.31
22,000 – 29,000 Lumens – Cobra Head	$ 14.57

4,500 – 6,000 Lumens – Open Bottom	$ 7.68
2,500 – 4,000 Lumens – Cobra Head	$ 8.03
4,000– 6,000 Lumens – Cobra Head	$ 8.57
4,500 – 6,000 Lumens – Directional (Flood)	$ 10.52
14,000 – 17,500 Lumens – Directional (Flood)	$ 12.41
22,000 – 28,000 Lumens – Directional (Flood)	$ 14.75
35,000 – 50,000 Lumens – Directional (Flood)	$ 21.42
Wood Pole	
PK5	$ 8.36

Underground:

	Fixture Only
Light Emitting Diode	
2,500 – 4,000 Lumens – Cobra Head	$ 3.93
4,000 – 6,000 Lumens – Cobra Head	$ 4.44
6,000 – 8,200 Lumens – Cobra Head	$ 5.25
13,000 – 16,500 Lumens – Cobra Head	$ 7.20
22,000 – 29,000 Lumens – Cobra Head	$ 10.46
4,000 – 7,000 Lumens Colonial, 4-Sided	$ 6.96
4,000 – 7,000 Lumens – Acorn	$ 8.46
4,000 – 7,000 Lumens – Contemporary	$ 6.65
8,000 – 11,000 Lumens – Contemporary	$ 7.99
13,500 – 16,500 Lumens – Contemporary	$ 9.86
21,000 – 28,000 Lumens – Contemporary	$ 14.32
45,000 – 50,000 Lumens – Contemporary	$ 19.96
4,500 – 6,000 Lumens – Directional (Flood)	$ 7.97
14,000 – 17,500 Lumens – Directional (Flood)	$ 9.86
22,000 – 28,000 Lumens – Directional (Flood)	$ 12.20
35,000 – 50,000 Lumens – Directional (Flood)	$ 18.87
4,000 – 7,000 Victorian	$ 21.13
Pole Charges	
Cobra	$ 12.42
Contemporary	$ 11.49
Post Top-Decorative Smooth	$ 8.53
Post Top-Historic Fluted	$ 14.27

One-Time Conversion Fee	$197.16
Conversion Fee per month for 60 months	$ 3.29

SCHEDULE RLS
RESTRICTED LIGHTING SERVICE

Overhead:

	Fixture Only	Fixture and Pole
High Pressure Sodium:		
4,000 Lumens - Cobra Head	$ 9.59	$ 13.10
5,800 Lumens - Cobra Head	$ 10.72	$ 14.60
9,500 Lumens - Cobra Head	$ 11.06	$ 15.17
22,000 Lumens - Cobra Head	$ 17.16	$ 21.56
50,000 Lumens - Cobra Head	$ 27.04	$ 29.98
50,000 Lumens - Cobra Head	$ 14.84	
5,800 Lumens - Open Bottom	$ 9.32	
9,500 Lumens - Open Bottom	$ 9.51	
9,500 Lumens – Directional (Flood)	$ 10.90	
22,000 Lumens – Directional (Flood)	$ 16.48	
50,000 Lumens – Directional (Flood)	$ 23.17	
Metal Halide:		
12,000 Lumens – Directional (Flood)	$ 17.41	$ 22.44
32,000 Lumens – Directional (Flood)	$24.29	$ 29.32
107,800 Lumens – Directional (Flood)	$ 50.14	$ 55.17
Mercury Vapor:		
7,000 Lumens - Cobra Head	$ 11.82	$ 14.12
10,000 Lumens - Cobra Head	$ 13.93	$ 15.88
20,000 Lumens - Cobra Head	$ 15.15	$ 17.76
7,000 Lumens - Open Bottom	$ 12.56	
Incandescent:		
1,000 Lumens - Tear Drop	$ 4.03	
2,500 Lumens - Tear Drop	$ 5.22	
4,000 Lumens - Tear Drop	$ 7.96	
6,000 Lumens - Tear Drop	$ 10.36	

Underground:

	Fixture Only	Decorative Smooth	Historic Fluted	Contem-porary
Metal Halide:				
12,000 Lumens – Directional (Flood)		$ 33.38		
32,000 Lumens – Directional (Flood)		$ 39.30		
107,800 Lumens – Directional (Flood)		$ 64.90		
12,000 Lumens – Contemporary	$ 18.81	$ 33.58		
32,000 Lumens – Contemporary	$ 26.27			$ 41.27
107,800 Lumens – Contemporary	$ 53.98	$ 68.74		

<u>High Pressure Sodium</u>:				
4,000 Lumens – Acorn		$ 17.33	$ 24.70	
5,800 Lumens - Acorn		$ 18.46	$ 26.22	
9,500 Lumens - Acorn		$ 18.79	$ 26.68	
4,000 Lumens – Colonial		$ 12.06		
5,800 Lumens – Colonial		$ 13.62		
9,500 Lumens – Colonial		$ 13.80		
5,800 Lumens – Coach		$ 36.32		
9,500 Lumens – Coach		$ 36.50		
5,800 Lumens – Contemporary	$ 18.39			$ 20.76
9,500 Lumens – Contemporary	$ 18.10			$ 25.45
22,000 Lumens – Contemporary	$ 21.15			$ 32.78
50,000 Lumens – Contemporary	$ 25.50			$ 40.27
4,000 Lumens – Dark Sky		$ 26.57		
9,500 Lumens – Dark Sky		$ 27.64		
5,800 Lumens – Victorian	$ 36.33			
9,500 Lumens – Victorian	$ 36.49			

<u>LE</u>
<u>LIGHTING SERVICE</u>

Energy Charge per kWh $0.07178

<u>SCHEDULE TE</u>
<u>TRAFFIC ENERGY SERVICE</u>

Basic Service Charge per Day	$ 0.13
Energy Charge per kWh	$ 0.08848

<u>EVSE</u>
<u>ELECTRIC VEHICLE SUPPLY EQUIPMENT</u>

Monthly Charging Unit Fee:

<u>Networked Charger:</u>	
Single Charger	$132.09
Dual Charger	$193.62
<u>Non-Networked Charger:</u>	
Single Charger:	$80.14

EVC-FAST
ELECTRIC VEHICLE FAST CHARGING SERVICE

Fee for use per kWh	$ 0.25

EF
EXCESS FACILITIES

Percentage With No Contribution-In-Aid-of-Constructing	1.14%
Percentage With Contribution-In-Aid-of-Construction	0.46%

RC
REDUNDANT CAPACITY

Charge per kW/kVA per month	
Secondary Distribution	$ 1.33
Primary Distribution	$ 0.90

EVSE-R
ELECTRIC VEHICLE SUPPLY EQUIPMENT

Monthly Charging Unit Fee:

Networked Charger:	
Single Charger	$121.79
Dual Charger	$173.02
Non-Networked Charger:	
Single Charger:	$ 30.58

OSL
OUTDOOR SPORTS LIGHTING SERVICE

Secondary Service:	
Basic Service Charge per Day	$ 2.96
Maximum Load Charge per kW:	
Peak Demand Period	$ 19.82
Base Demand Period	$ 2.93
Energy Charge per kWh	$ 0.02909
Primary Service:	
Basic Service Charge per Day	$ 7.89
Maximum Load Charge per kW:	
Peak Demand Period	$ 16.43
Base Demand Period	$ 2.51
Energy Charge per kWh	$ 0.02573

ERS

ECONOMIC RELIEF SURCREDIT

All Rate Schedules per 100 cubic feet	$ (0.00068)

SCHEDULE SPECIAL CHARGES

Returned Payment Charge	$ 3.50
Meter Test Charge	$ 79.00
Disconnect/Reconnect Charge	$ 37.00
Disconnect/Reconnect Temporary Suspension	$ 37.00
Remote Disconnect/Reconnect with Reconnection Capability	$ 0.00
Remote Disconnect/Reconnect Temporary Suspension	$ 0.00
Meter Pulse Charge	$ 21.00
Unauthorized Connection Charge	
No Meter Replacement	$ 45.00
Single-Phase Meter Replacement	$ 66.00
Single-Phase AMR Meter	$ 87.00
Single-Phase AMI Meter	$149.00
Three-Phase Meter Replacement	$154.00
AMI Opt-Out	
One Time Fee	$ 39.00
Monthly Fee per Delivery Point	$ 15.00
TS - Temporary-to-Permanent	15.00%
TS – Seasonal	100.00%
Late Payment Charge	
Rates RS, RTOD-Energy, RTOD-Demand, VFD	
GS, GTOD-Energy, GTOD-Demand, AES, PSA	3.00%
Rates PS, TODS, TODP, RTS, FLS OSL	1.00%

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00349 DATED JUN 30 2021

Adjustments to KU's Cost of Capital

I. KU Capital Structure, Cost of Capital, and Gross Revenue Conversion Factor Per Filing

	Adjusted Jurisdictional Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	89,959,385	1.72%	0.463%	0.01%	0.01%
Long Term Debt	2,358,710,662	45.05%	4.160%	1.87%	1.88%
Common Equity	2,787,080,390	53.23%	10.000%	5.32%	7.13%
Total Capital	5,235,750,437	100.00%		7.21%	9.02%

II. Reduce Long-Term Debt Rate

	Adjusted Jurisdictional Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	89,959,385	1.72%	0.463%	0.01%	0.01%
Long Term Debt	2,358,710,662	45.05%	4.140%	1.87%	1.87%
Common Equity	2,787,080,390	53.23%	10.000%	5.32%	7.13%
Total Capital	5,235,750,437	100.00%		7.20%	9.01%

Change in Grossed Up COC	-0.01%
Capitalization	5,235,750,437
Change in Revenue Requirement	(471,305)

III. Reduce Return on Common Equity to 9.425%

	Adjusted Jurisdictional Capitalization	Adjusted Capital Ratio	Component Costs	Weighted Avg Cost	Grossed Up Cost
Short Term Debt	89,959,385	1.72%	0.463%	0.01%	0.01%
Long Term Debt	2,358,710,662	45.05%	4.140%	1.87%	1.87%
Common Equity	2,787,080,390	53.23%	9.425%	5.02%	6.72%
Total Capital	5,235,750,437	100.00%		6.89%	8.60%

Change in Grossed Up COC	-0.41%
Capitalization	5,235,750,437
Change in Revenue Requirement	(21,459,174)

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00349 DATED JUN 30 2021

	Adjusted Stipulation	Stipulation	
	($ Millions)		
	Amount	Amount	Difference
Base Rate Increase Requested by KU	169.90	169.90	-
Reduce Pension and OPEB Expenses	(3.90)	(3.90)	-
Reduce Depreciation Expense to Reflect Present Rates for Brown 3	(33.00)	(33.00)	-
Remove Forecasted Legal Fees	(4.26)	-	(4.26)
Remove EEI Dues	(0.45)	-	(0.45)
Adjust Rate Case Expense to Actual	(0.05)	-	(0.05)
Reduce Long-Term Debt Rate Related to June 30, 2021 Issuance	(0.47)	(0.40)	(0.07)
Reduce Return on Equity from 10.0%	(21.46)	(16.70)	(4.76)
Total Adjustments to Base Rate Increase	(63.58)	(54.00)	(9.58)
Base Rate Increase After Adjustments	106.32	115.90	(9.58)

APPENDIX E

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00349 DATED JUN 30 2021

AMI quantitative benefits monitored pursuant to ordering paragraph 7 of this Order.

BENEFITS	CITATION TO CASE RECORD
Reduced meter reading expenses	Bellar Direct Testimony at 54 and Exhibit LEB3 at A13-A15; Saunders Direct Testimony at 32-33
Ability to disconnect/reconnect remotely	Wolfe Direct Testimony at 28; Saunders Direct Testimony at 28
Reduced field service costs	Bellar Direct Testimony at 55 and Exhibit LEB3 at A15–A16; Wolfe Direct Testimony at 24–25
Avoided meter costs	Bellar Direct Testimony at 55
Fuel savings from decreased customer usage	Bellar Direct Testimony at 55 and Exhibit LEB3 at A18–A20
Conservative Voltage Reduction.	Bellar Direct Testimony at 61; Wolfe Direct Testimony at 21
Time of day rates	Bellar Testimony at 58
Electric Distribution Operations	Bellar Direct Testimony, Exhibit LEB3 at A17–A18
Improved outage response	Wolfe Direct Testimony at 22–24 and Exhibit JKW2 at 15–27
Management and prediction of outages, overloads, and shortfalls of transmission and distribution assets.	Wolfe Direct Testimony at 25–27
Data availability to customers within 406 hours	Bellar Direct Testimony at 58
Innovative Rate Design	Bellar Direct Testimony at 58
Reduced Theft and Earlier Detection	Bellar Direct Testimony at 60

*Honorable Allyson K Sturgeon
Managing Senior Counsel - Regulatory &
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202

*Honorable David Edward Spenard
Strobo Barkley PLLC
239 South 5th Street
Ste 917
Louisville, KENTUCKY 40202

*John Horne
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Angela M Goad
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Emily W Medlyn
General Attorney
U.S. Army Legal Services Agency Regul
9275 Gunston Road
Fort Belvoir, VIRGINIA 22060

*Honorable Kurt J Boehm
Attorney at Law
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

*Barry Alan Naum
Spilman Thomas & Battle, PLLC
1100 Brent Creek Blvd., Suite 101
Mechanicsburg, PENNSYLVANIA 17050

*Thomas J FitzGerald
Counsel & Director
Kentucky Resources Council, Inc.
Post Office Box 1070
Frankfort, KENTUCKY 40602

*Honorable Kendrick R Riggs
Attorney at Law
Stoll Keenon Ogden, PLLC
2000 PNC Plaza
500 W Jefferson Street
Louisville, KENTUCKY 40202-2828

*Clay A. Barkley
Strobo Barkley PLLC
239 South 5th Street
Ste 917
Louisville, KENTUCKY 40202

*G. Houston Parrish
Labor Law Attorney
Office of the Staff Judge Advocate, B
50 3rd Avenue
Fort Knox, KENTUCKY 40121

*Larry Cook
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Carrie H Grundmann
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, NORTH CAROLINA 27103

*James W Gardner
Sturgill, Turner, Barker & Moloney, PLLC
333 West Vine Street
Suite 1400
Lexington, KENTUCKY 40507

*Matt Partymiller
President
Kentucky Solar Industries Association
1038 Brentwood Court
Suite B
Lexington, KENTUCKY 40511

*Honorable David J. Barberie
Managing Attorney
Lexington-Fayette Urban County Government
Department Of Law
200 East Main Street
Lexington, KENTUCKY 40507

*Jody M Kyler Cohn
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

*Matthew Miller
Sierra Club
50 F Street, NW, Eighth Floor
Washington, DISTRICT OF COLUMBIA 20001

*Don C Parker
Spilman Thomas & Battle, PLLC
300 Kanawha Blvd, East
Charleston, WEST VIRGINIA 25301

*Joe F. Childers
Childers & Baxter PLLC
300 Lexington Building, 201 West Sho
Lexington, KENTUCKY 40507

*J. Michael West
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Honorable Michael L Kurtz
Attorney at Law
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

*Kentucky Utilities Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40232-2010

*Rick LoveKamp
Kentucky Utilities Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40202

*M. Todd Osterloh
Sturgill, Turner, Barker & Moloney, PLLC
333 West Vine Street
Suite 1400
Lexington, KENTUCKY 40507

*Honorable Robert C Moore
Attorney At Law
Stites & Harbison
421 West Main Street
P. O. Box 634
Frankfort, KENTUCKY 40602-0634

*Robert Conroy
Vice President, State Regulation and Rates
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202

*Randal A. Strobo
Strobo Barkley PLLC
239 South 5th Street
Ste 917
Louisville, KENTUCKY 40202

*Sara Judd
Senior Corporate Attorney
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202

*Susan Speckert
Lexington-Fayette Urban County Government
Department Of Law
200 East Main Street
Lexington, KENTUCKY 40507