COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

O R D E R

On May 30, 2025,[1] Kentucky Utilities Company (KU) filed an application for a general adjustment of its base rates using a forecasted test year and included other related requests for accounting treatments and tariff changes. The application proposed the rates become effective on July 1, 2025.[2] On June 18, 2025, the Commission issued an Order that suspended the effective date of the proposed rates for six months, up to and including December 31, 2025.[3]

PROCEDURAL HISTORY

The following parties sought and were granted intervention in this proceeding: (1) the Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General);[4] (2) Kentucky Industrial Utility Customers, Inc.

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[1] While the original Application was deemed deficient by the Commission via its Order issued June 16, 2025, the Commission, in that same Order, granted KU a deviation from its notice deficiencies and deemed the Application filed on May 30, 2025.

[2] Application, Tab 4.

[3] Order (Ky. PSC June 18, 2025).

[4] Order (Ky. PSC May 27, 2025).

(KIUC);[5] (3) Sierra Club;[6] (4) Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association (collectively, Joint Intervenors);[7] (5) Lexington-Fayette Urban County Government (LFUCG);[8] (6) Kentucky Broadband and Cable Association (KBCA);[9] (7) Walmart, Inc. (Walmart);[10] (8) Kroger, Inc. (Kroger)[11]; (9) Kentucky Solar Industries Association (KYSEIA)[12]; (10) and the United States Department of Defense and all other federal executive agencies (DOD/FEA)[13]. On August 20, 2025, a request from Rick Thompson to intervene was denied.[14]

An informal conference was held on June 10, 2025 to discuss the notice given in this matter.[15] On June 18, 2025, the Commission issued a procedural schedule.[16] On August 19, 2025, an informal technical conference (ITC) was held.[17] On August 25, 2025, KU filed supplemental responses to Commission Staff's First Request for Information

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[5] Order (Ky. PSC June 10, 2025).

[6] Order (Ky. PSC July 2, 2025).

[7] Order (Ky. PSC July 3, 2025).

[8] Order (Ky. PSC July 2, 2025).

[9] Order (Ky. PSC July 1, 2025).

[10] Order (Ky. PSC July 2, 2025).

[11] Order (Ky. PSC July 2, 2025).

[12] Order (Ky. PSC July 2, 2025).

[13] Order (Ky. PSC July 1, 2025).

[14] Order (Ky. PSC Aug. 20, 2025).

[15] PSC Letter Filing IC Memo and Sign In Sheet into the Record (filed Sept. 3, 2025).

[16] Order (Ky. PSC June 18, 2025).

[17] Order (Ky. PSC Oct. 7, 2025.

which impacted KU's requested revenue increase.[18] Although KU did not amend its application, based on the supplemental responses, KU's calculated required revenue increase was reduced to $220.1 million from the original application of $226.1 million.[19] On August 27, 2025, the procedural schedule was amended to allow for another round of requests for information and to allow the Attorney General/KIUC revenue requirement witness additional time to tender testimony.[20] An informal conference was also held on October 8 and 9, 2025.[21] On October 15, 2025, KU submitted its base period update to filing requirements.[22]

KU responded to seven requests for information from Commission Staff.[23] KU responded to three requests for information issued jointly from the Attorney General and

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[18] KU's Supplemental Response to Commission Staff's First Request for Information (Aug. 25, 2025 Supplemental Filing) (filed Aug. 25, 2025).

[19] KU's Aug. 25, 2025 Supplemental Filing, Item 54.

[20] Order (Ky. PSC Aug. 27, 2025).

[21] Order (Ky. PSC Sept. 19, 2025).

[22] KU's Base Period Update to Filing Requirements (Base Period Update) (filed Oct. 15, 2025).

[23] KU's Response Commission Staff's First Request for Information (Staff's First Request) (filed June 13, 2025); KU's Response to Commission Staff's Second Request for Information (Staff's Second Request) (filed July 16, 2025); KU's Response to Commission Staff's Third Request for Information (Staff's Third Request) (filed Aug. 12, 2025); KU's Response to Commission Staff's Fourth Request for Information (Staff's Fourth Request) (filed Sept. 23, 2025); KU's Response to Commission Staff's Fifth Request for Information (Staff's Fifth Request) (Oct. 10, 2025); KU's Response to Commission Staff's Sixth Request for Information (Staff's Sixth Request) (Oct. 20, 2025); KU's Response to Commission Staff's Post-Hearing Request for Information (Staff's Post-Hearing Request) (filed Nov. 25, 2025).

KIUC.[24] KU responded to three requests for information from Sierra Club.[25] KU responded to four requests for information from KYSEIA.[26] KU responded to four requests for information from Joint Intervenors.[27] KU responded to three requests for information from LFUCG.[28] KU responded to three requests for information from KBCA.[29] KU responded to two requests for information from Walmart.[30] Kroger did not file any requests for information. KU responded to one request for information from DOD/FEA.[31]

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[24] The Attorney General and KIUC agreed to sponsor witnesses together. A memorandum of understanding was filed into the record on Sept. 4, 2025. KU's Response to Attorney General/KIUC's First Request for Information (Attorney General/KIUC's First Request) (filed July 16, 2025); KU's Response to Attorney General/KIUC's Second Request for Information (Attorney General/KIUC's Second Request) (filed Aug. 12, 2025); KU's Response to Attorney General/KIUC's Post-Hearing Request for Information (Attorney General/KIUC's Post-Hearing Request) (filed Nov. 25, 2025).

[25] KU's Response to Sierra Club's First Request for Information (Sierra Club's First Request) (filed July 16, 2025); KU's Response to Sierra Club's Second Request for Information (Sierra Club's Second Request) (filed Aug. 12, 2025); KU's Response to Sierra Club's Post-Hearing Request for Information (Sierra Club's Post-Hearing Request) (filed Nov. 25, 2025).

[26] KU's Response to KYSEIA's First Request for Information (KYSEIA's First Request) (filed July 16, 2025); KU's Response to KYSEIA's Second Request for Information (KYSEIA's Second Request) (filed Aug. 12, 2025); KU's Response to KYSEIA's Third Request for Information (KYSEIA's Third Request) (filed Sept. 23, 2025); KU's Response KYSEIA's Post-Hearing Request for Information (KYSEIA's Post-Hearing Request) (filed Nov. 25, 2025).

[27] KU's Response to Joint Intervenors' First Request for Information (Joint Intervenors' First Request) (filed July 16, 2025); KU's Response to Joint Intervenors' Second Request for Information (Joint Intervenors' Second Request) (filed Aug. 12, 2025); KU's Response to Joint Intervenors' Third Request for Information (Joint Intervenors' Third Request) (filed Sept. 23, 2025); KU's Response to Joint Intervenors' Post-Hearing Request for Information (Joint Intervenors' Post-Hearing Request) (filed Nov. 25, 2025).

[28] KU's Response to LFUGC's First Request for Information (LFUGC's First Request) (filed July 16, 2025); KU's Response to LFUGC's Second Request for Information (LFUGC's Second Request) (filed Aug. 12, 2025); KU's Response to LFUGC's Post-Hearing Request for Information (LFUGC's Post-Hearing Request) (filed Nov. 25, 2025).

[29] KU's Response to KBCA's First Request for Information (KBCA's First Request) (filed July 16, 2025); KU's Response to KBCA's Second Request for Information (KBCA's Second Request) (filed Aug. 12, 2025); KU's Response to KBCA's Third Request for Information (KBCA's Third Request) (filed Sept. 23, 2025).

[30] KU's Response to Walmart's First Request for Information (Walmart's First Request) (filed July 16, 2025); KU's Response to Walmart's Second Request for Information (Walmart's Second Request) (filed Aug. 12, 2025).

[31] KU's Response to DOD/FEA's First Request for Information (DOD/FEA's First Request) (filed July 16, 2025).

The Attorney General/KIUC responded to four requests for information.[32] KBCA responded to one request for information.[33] KYSEIA responded to two requests for information.[34] DOD/FEA responded to two requests for information.[35] Walmart responded to two requests for information.[36] Sierra Club responded to one request for information.[37] Joint Intervenors responded to one request for information.[38]

The Commission held four public comment meetings.[39] In addition, there were numerous written public comments submitted.[40] The public comments generally opposed any rate increase.

On October 20, 2025, LG&E/KU jointly filed a Stipulation and Recommendation (Stipulation) more fully described below.[41] Thereafter, the Commission held an evidentiary hearing in this matter from November 3, 2025, through November 5, 2025.

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[32] Attorney General/KIUC's Response to Commission Staff's First Request for Information (filed Sept. 16, 2025); Attorney General/KIUC's Response to KU's First Request for Information (filed Sept. 16, 2025); Attorney General/KIUC's Response to KYSEIA's First Request for Information (filed Sept. 16, 2025); Attorney General/KIUC's Response to Commission Staff's Post-Hearing Request for Information (Nov. 25, 2025).

[33] KBCA's Response to KU's First Request for Information (filed Sept 23, 2025).

[34] KYSEIA's Response to Commission Staff's First Request for Information (filed Sept. 23, 2025); KYSEIA's Response to KU's First Request for Information (filed Sept. 23, 2025).

[35] DOD/FEA's Response to KU's First Request for Information (filed Sept. 23, 2025); DOD/FEA's Response to Commission Staff's First Request for Information (filed Sept. 23, 2025).

[36] Walmart's Response to Commission Staff's First Request for Information (filed Sept. 23, 2025); Walmart's Response to KU's First Request for Information (filed Sept. 23, 2025).

[37] Sierra Club's Response to KU's First Request for Information (filed Sept. 23, 2025).

[38] Joint Intervenors' Response to Commission Staff's Post-Hearing Request for Information (Nov. 25, 2025).

[39] The local comments meetings were held on September 8, 2025 in Louisville, KY; October 30, 2025 in Madisonville, KY; October 14, 2025 in Lexington, KY; and October 16, 2025 in Middlesboro, KY.

[40] View Public Comments for: 2025-00113.

[41] KU Stipulation Testimony of Robert Conroy and Christopher Garrett (Stipulation Testimony), Exhibit 1, Stipulation and Recommendation (Stipulation) (filed Oct. 20, 2025).

Testimony at the beginning of the hearing was slightly delayed to provide opportunity for the parties to review KU's, as well as LG&E's, October 31, 2025 filing.[42] The Commission also incorporated by reference filings made on or after May 30, 2025, through the final Order in Case No. 2025-00045.[43] The parties filed briefs on December 2, 2025, with the exception of DOD/FEA who did not file a brief.

On December 8, 2025, KU filed a notice of its intent to implement rates on January 1, 2026.[44] On December 10, 2025, KIUC filed a response to the notice.[45] On December 22, 2025, the Commission issued an Order requiring KU to implement the rates it gave notice of in its application, not the rates agreed to as part of the Stipulation, subject to refund.[46] This case is now submitted for decision.

BACKGROUND

KU is an investor-owned utility that generates and purchases electricity, and distributes and sells electricity at retail.[47] KU is incorporated in the Commonwealth of Kentucky and the Commonwealth of Virginia and is currently in good standing in both states.[48] It distributes and sells electricity at retail in Adair, Anderson, Ballard, Barren, Bath, Bell, Bourbon, Boyle, Bracken, Bullitt, Caldwell Campbell, Carlisle, Carroll, Casey,

[42] KU Supplemental Stipulation Testimony of Robert Conroy and Christopher Garrett (Supplemental Stipulation Testimony) (filed Oct. 31, 2025).

[43] Case No. 2025-00045, *Electronic Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates;* Schram Direct Testimony (filed Feb. 28, 2025); Order (Ky. PSC Nov. 11, 2025).

[44] KU's Notice of Implementation of Rates (filed Dec. 8, 2025).

[45] KIUC's Response to KU's Notice (filed Dec. 10, 2025).

[46] Order (Ky. PSC Dec. 22, 2025).

[47] Application at 2.

[48] Application at 2.

Christian, Clark, Clay, Crittenden, Daviess, Edmonson, Estill, Fayette, Fleming, Franklin, Fulton, Gallatin, Garrard, Grant, Grayson, Green, Hardin, Harlan, Harrison, Hart, Henderson, Henry, Hickman, Hopkins, Jessamine, Knox, Larue, Laurel, Lee, Lincoln, Livingston, Lyon, Madison, Marion, Mason, McCracken, McCreary, McLean, Mercer, Montgomery, Muhlenberg, Nelson, Nicholas, Ohio, Oldham, Owen, Pendleton, Pulaski, Robertson, Rockcastle, Rowan, Russell, Scott, Shelby, Spencer, Taylor, Trimble, Union, Washington, Webster, Whitley, and Woodford counties, Kentucky.[49]

KU is a subsidiary of LG&E and KU Energy LLC (LKE).[50] LG&E and KU Energy LLC (LKE) is a wholly owned subsidiaries of PPL Corporation (PPL).[51] LG&E and KU Services Company (LKS) employees provide both operational and shared service functions for LKE subsidiaries, principally LG&E and KU.[52]

LEGAL STANDARD

Pursuant to KRS 278.030(1), the Commission's standard of review for a utility's request for a rate increase is whether the proposed rates are "fair, just and reasonable." KU bears the burden of proof to show that the proposed rates are fair, just and reasonable under the requirements of KRS 278.190(3).

KRS 278.010 states, "an affiliate means a person that controls or that is controlled by, or is under common control with, a utility". Pursuant to KRS 278.2207(1)(a), "services and products provided to the utility by an affiliate shall be priced at the affiliate's fully

[49] Application at 3-4.

[50] Application, Tab 51, Cost Allocation Manual at 9.

[51] Application, Tab 42.

[52] Application, Tab 51, Cost Allocation Manual at 7.

distributed cost but in no event greater than market or in compliance with the utility's existing USDA, SEC, or FERC approved cost allocation methodology." Further, "[i]n any formal commission proceeding in which cost allocation is at issue, a utility shall provide sufficient information to document that its cost allocation procedures and affiliate transaction pricing are consistent with the provisions of this chapter."[53] If a utility has failed to provide sufficient evidence of its compliance, the Commission may "[o]rder that the costs attached to any transaction be disallowed from rates."[54]

KU's application also requested approval for the establishment of a regulatory asset for storm damage restoration, vegetation management costs, and software implementation costs. KRS 278.220 provides that the Commission may establish a uniform system of accounts (USoA) for utilities. The system of accounts should conform as nearly as practicable to the system adopted or approved by the Federal Energy Regulatory Commission (FERC). The FERC USoA provides for regulatory assets, or the capitalization of costs that would otherwise be expensed but for the actions of a rate regulator. The Financial Accounting Standards Board's Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation, which was codified as Accounting Standards Codification (ASC) 980, Regulated Operations, provides the criteria for recognition of a regulatory asset.[55] Pursuant to ASC

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[53] KRS 278.2209.

[54] KRS 278.2211(1)(b).

[55] ASC 980-340-25-1 provides, in full, as follows:

> **25-1** Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part

980, it must be probable that the utility will recover approximately equal revenue through the inclusion of these costs for ratemaking purposes, with the intent to recover the previously incurred cost not a similar future cost.

In prior matters, the Commission has identified, generally, parameters for expenses that may qualify for regulatory asset treatment and has approved regulatory assets when a utility has incurred (1) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (2) an expense resulting from a statutory or administrative directive; (3) an expense in relation to an industry sponsored initiative; or (4) an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the cost.[56] Additionally, the Commission has established a requirement that utilities seek Commission approval before recording regulatory assets,[57] and requirements regarding the timing for applications seeking such

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> of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:
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> > a. It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.
> >
> > b. Based on available evidence; the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost. A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.

[56] Case No. 2008-00436, *Application of East Kentucky Power Cooperative, Inc. for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to Certain Replacement Power Costs Resulting from Generation Forced Outages* (Ky. PSC Dec. 23, 2008), Order at 3–4.

[57] Case No. 2016-00180, *Application of Kentucky Power Company for an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities Related to the Extraordinary Expenses Incurred by Kentucky Power Company in Connection with the Two 2015 Major Storm Events* (Ky. PSC Nov. 3, 2016), Order at 9.

approval.[58] In addition, outside of the prescribed categories of expenses that qualify for regulatory asset treatment, utilities have established regulatory assets for certain timing and accounting differences, such as over- or under-recoveries for riders.

Other applicable legal standards will be discussed within the relevant section of the Order set forth below.

APPLICATION SUMMARY

KU proposed the following in its application:

1. KU proposed to change its existing electric rates and tariffs to those rates and charges set forth in the proposed tariffs which would result in an increase in annual revenues of approximately $226.1 million, or 11.5 percent, for the forecasted test period compared to the operating revenues for the forecasted test period under existing electric rates.[59]

2. KU requested approval of revised tariff sheets for electric service.[60]

3. KU proposed that recovery of $32,007,478 of storm damage regulatory assets be amortized over a five-year period beginning when new rates take effect from this proceeding.[61]

4. KU proposed to establish a regulatory asset to be amortized over the depreciable lives of its information technology (IT) upgrades beginning with the associated in-service dates.[62]

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[58] Case No. 2016-00180, Dec. 12, 2016 Order at 5.

[59] Application at 4.

[60] Application at 18.

[61] Application at 11.

[62] Application at 11.

5. KU requested that recovery of its regulatory assets associated with its AMI project be amortized over a period of fifteen years consistent with the depreciable lives of the underlying AMI assets and the regulatory liabilities be amortized over a period of five years to mitigate the financial impact of the AMI implementation to customers.[63]

6. KU requested authority to net actual storm damage restoration and vegetation management costs against the respective amounts in base rates in the forecasted test period and record a regulatory asset or liability for the difference.[64]

7. KU requested that recovery of the balance of the regulatory asset associated with the Glendale Megasite of $8.6 million be amortized over a five-year period beginning when new rates take effect from this case.[65]

8. KU requested permission to accumulate and defer for future recovery any incremental expenses above the amounts currently embedded in base rates for costs incurred for de-pancaking expenses. KU requested the associated regulatory liability or regulatory asset be recorded net of any related Open Access Transmission Tariff (OATT) transmission revenue offsets.[66]

9. KU requested approval of Adjustment Clause Renewable Power Purchase Agreement (RPPA) – a separate adjustment clause designed to recover the cost of solar power purchase agreements (PPAs) and other future renewable energy PPAs.[67]

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[63] Application at 13.

[64] Application at 13.

[65] Application at 14.

[66] Application at 14.

[67] Application at 14.

10. KU requested approval of the filed depreciation rates.[68]

11. KU requested the Commission relieve it of the obligation to file an annual Regional Transmission Organization (RTO) membership study in favor of filing such a study triennially with each IRP.[69]

12. KU requested relief from the Merger Commitment Regarding LG&E and KU Foundation.[70]

13. KU requested a deviation from the requirements of 807 KAR 5:041, Section 7, that would permit it to satisfy the regulation's voltage survey and three-year recordkeeping requirements using available AMI data instead of portable or recording voltmeters, and excuse it from the requirements in Section 7(2) pertaining to maintenance and recordkeeping for voltmeters.[71]

14. KU requested the Commission find that a deviation from the regulation on service terminations is not required for the prepay program or, in the alternative, that such deviation should be granted for good cause shown.[72]

15. KU requested granting all other relief to which KU may be entitled.[73]

STIPULATION AND RECOMMENDATION

On October 20, 2025, KU, LG&E, the Attorney General, KIUC, LFUCG, Louisville Metro, Walmart, DoD/FEA, Sierra Club, and Kroger (Signing Parties) entered into a

[68] Application at 15.

[69] Application at 16.

[70] Application at 16.

[71] Application at 17.

[72] Application at 17.

[73] Application at 19.

Stipulation, attached to this Order as Appendix A. The Signing Parties stated that absent express agreement stated in the Stipulation, the Stipulation does not represent agreement on any specific claim, methodology, or theory supporting the appropriateness of any proposed or recommended relief, matters, or issues addressed by the Stipulation.[74] The Signing Parties also agreed that the Stipulation, viewed in its entirety, is a fair, just and reasonable resolution of the issues resolved in the Stipulation.[75] Joint Intervenors, KBCA, and KYSEIA did not join the Stipulation.[76] Along with the Stipulation, KU filed supporting testimony.[77] On November 5, 2025, KU filed an amendment to the Stipulation (Amended Stipulation), attached to this Order as Appendix B.[78] A summary of the provisions contained in the Stipulation and the amended Stipulation are as follows:[79]

- LG&E and KU committed to a base-rate “stay out” until August 1, 2028, such that any changes from base rates approved in Case Nos. 2025-00113 and 2025-00114 shall not take effect before that date. Therefore, LG&E or KU may file base rate applications no sooner than January 1, 2028, but the proposed base rates shall not take effect before August 1, 2028.
- LG&E and KU will retain the independent right to seek the approval from the Commission for the deferral of:

[74] Joint Stipulation Testimony of Robert Conroy and Christopher Garrett (Stipulation Testimony) (filed Oct. 20, 2025), Exhibit 1 at 2. Note that the Stipulation was subsequently amended to include a catch-all provision and to clarify that the Stipulation and Recommendation does not address or include Adjustment Clause MC2 and therefore the Stipulating Parties are not limited in the positions they may take in these proceedings MC2.

[75] Stipulation Testimony, Exhibit 1 at 2.

[76] Stipulation Testimony, Exhibit 1 at 2.

[77] Stipulation Testimony.

[78] KU and LG&E’s Notice of Filing of Amendment to Stipulation and Recommendation (Amended Stipulation) (filed Nov. 5, 2025).

[79] The Stipulation provisions summarized here relate to provisions for KU and LG&E. The Commission will only discuss the provisions related to KU throughout this Order.

  - extraordinary, nonrecurring expenses that could not have been reasonably anticipated or included in LG&E/KU's planning;
  - expenses resulting from statutory or administrative directives that could not have been reasonably anticipated or included in LG&E or KU's planning;
  - expenses in relation to government or industry-sponsored initiatives; or
  - extraordinary or nonrecurring expenses that, over time, will result in savings that fully offset the costs.
- LG&E and KU 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.
- The stay out provision shall not apply, directly or indirectly, to the operation of any of LG&E or 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.
- 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.
- The overall base rate electric revenue requirement increases resulting from the stipulated adjustments are $132,000,000 for KU.
- The Signing Parties stipulated that increases in annual revenues for LG&E electric operations and for KU operations should be effective for service rendered on and after January 1, 2026.
- The chart below shows stipulated revenue requirement increases as adjusted from the revenue requirement increases requested in KU's Application.

Item	KU ($M)
Filed Electric Revenue Requirement Increases as Adjusted	$ 219.9
9.90% Return on Equity	(45.9)
Updated Long-Term Debt Rate	(4.4)
Updated Depreciation Expense to Remove Terminal Net Salvage	(16.0)
Updated Vegetation Management Expense	(8.8)
Updated De-Pancaking Expense	(6.3)
Removed EEI and Related Dues	(0.5)
Removed 401(k) Matching for Employees in Defined Benefit Plan	(0.9)
Updated Pension and OPEB Expense	(1.3)
Depreciation Error	(3.8)
Electric Revenue Requirement Increases After Stipulated Adjustments	$ 132.0

- The Signing Parties agreed the Commission should approve deferral accounting treatment for LG&E and KU for any actual expense amounts above or below the expense levels in base rates for the following items:
    - Pension and Other Post Retirement Benefits (OPEB) Expense;
    - Storm Damage Expense;
    - Vegetation Management Expense;
    - De-Pancaking Expense; and
    - Inline Inspection and Well Logging Expense.
- For these items, LG&E and KU will establish a regulatory asset for amounts exceeding the base rate level and a regulatory liability for amounts below the base rate level.
- LG&E and KU will address recovery of any regulatory assets or liabilities in LG&E and KU's next base rate cases.
- LG&E and KU will make an annual filing with the Commission within 90 days of the end of each calendar year to report on and have Commission review of the deferred storm restoration and vegetation management amounts. Additionally, LG&E/KU will report on Pension and OPEB expense, de-pancaking, and inline inspection and well logging expense in this annual filing.
- The Signing Parties recommended to the Commission that, effective January 1, 2026, LG&E and KU shall implement the electric and gas rates as set forth in the proposed tariff sheets.

- The Signing Parties agreed LG&E and KU's overall residential rate increase percentage and the residential Basic Service Charge increase percentage (i.e., for Rates RS, RTOD-Energy, RTOD-Demand, and RGS) will be the system average increase percentage for the relevant Utility, as adjusted for rounding.

- The Signing Parties agreed to subsidy reductions.

- The Signing Parties agreed, and stated the Commission should authorize LG&E and KU to recover all non-fuel costs of all new generation and energy storage assets approved by the Commission, but not yet in service, as of the date of the final Order in these proceedings, excluding Mill Creek 6, through a permanent Generation Cost Recovery Adjustment Clause (Adjustment Clause GCR).

- The Signing Parties agreed the Commission should approve a new time-limited Sharing Mechanism Adjustment Clause (Adjustment Clause SM) to facilitate the rate case stay-out.

- The Signing Parties agreed LG&E and KU will propose a modification to Rate EHLF (Extremely High Load Factor) to reflect a minimum contract capacity threshold of 50 MVA.

- The Signing Parties agreed LG&E and KU will propose to add tariff language to Rate EHLF to clarify the following:

  - Rate EHLF applies only to new customers and

  - If a customer attempts to circumvent the minimum capacity threshold of Rate EHLF by siting multiple smaller facilities, the customer will nonetheless be served under Rate EHLF.

- LG&E and KU committed to work with Rate EHLF customers in good faith to reach any necessary agreements to reasonably accommodate such customers' renewable energy goals.

- The Signing Parties agreed LG&E and KU will update the depreciation lives for Mill Creek 5 Generating Station (Mill Creek 5), Mill Creek 6 Generating Station (Mill Creek 6), and Brown 12 Generating Station (Brown 12) to 45 years.

- In their next base rate cases, LG&E and KU will present their rate base calculations with regulatory assets and liabilities included.

- LG&E and KU agreed to study seasonal residential rates and present the results of such study in their next base rate cases.

- LG&E and KU agreed to work with Walmart to propose an EV fast charger rate in their next base rate cases.

- The Signing Parties agreed LG&E and KU will modify their tariffs to make Green Tariff Option #3 available to customers served under Rate PS so long as the rate design proposed by this Stipulation is approved by the Commission.

- The Signing Parties agreed to stipulated Rate PSA rates that reflect the stipulated return on equity and updated long-term debt rate.

- The Signing Parties agreed that Rate LS rates will be reduced to reflect the stipulated reduction in cost of capital.

- The Signing Parties agreed LG&E and KU will propose a modification to Rate RTS and TODP to a revenue-neutral rate design to lower energy charges and increase demand charges. The stipulated rate increase will be applied to demand charges.

- The Signing Parties agreed LG&E and KU will increase the basic service charge for Rate CGS by 25 percent.

- The Signing Parties agree LG&E and KU will remove legacy status from the legacy customers that meet the availability requirements of their rate schedules. Rates PS and GS customers that do not meet the availability requirements of their rate schedules will continue to maintain legacy status.

- The Signing Parties agreed LG& and KU will increase all CSR-1 and CSR-2 rates and penalties by 40 percent.

- LG&E and KU agreed to withdraw their requested changes to the liability provisions in their tariffs.

- LG&E and KU agreed they will not close their NMS-2 rates to new participants earlier than the effective date of new rates resulting from their next base rate cases. LG&E and KU will leave the NMS-2 rates at their current level.

- LG&E and KU committed to continue their proactive streetlight inspections and smart streetlight efforts for LFUCG and Louisville Metro. LG&E and KU will work cooperatively with LFUCG and Louisville Metro regarding such inspection programs and smart streetlight efforts, and they will provide reasonable additional reporting to LFUCG and Louisville Metro concerning the same. LFUCG and Louisville Metro acknowledged that smart streetlights may reduce the need for streetlight inspections over time.

- The Signing Parties recommend that, except as modified in the Stipulation, all other relief requested in LG&E and KU's filings in this matter, including without limitation all rates, terms, conditions, and deferral accounting, should be approved as filed or as later corrected or amended by LG&E and KU.

- The Stipulation and Recommendation does not address or include Adjustment Clause MC2 and therefore the Signing Parties are not limited in the positions they may take in these proceedings regarding Adjustment Clause MC2.

ANALYSIS AND DETERMINATION

As the Commission noted in Case No. 2025-00045,[80] demand for electricity is currently in a state of flux, with high-projected demand coupled with significant uncertainty about whether, or when, that demand will materialize. The high level of uncertainty complicates the already often arduous long-term planning process that utilities rely on to make costly generation and transmission decisions. In addition, this planning process requires utilities to balance their mandate to serve current ratepayers who will be impacted by decisions to construct new generation and transmission infrastructure against the utilities' need to have sufficient headroom to reliably serve new load as it materializes on the grid for decades to come. The utilities must also then consider who should bear the cost of these investments while maintaining fair, just and reasonable rates.

When viewing the proposed Stipulation holistically, the Commission finds it compelling. The Commission agrees with the Signing Parties of the proposed Stipulation that ensuring sufficient revenue to maintain utility stability is essential in order to fulfill the agreed upon stay out provision. However, the current economic and energy uncertainty must be balanced against the interests of customers of both LG&E and KU.[81] The current

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[80] Case No. 2025-00045, *Electronic Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates* (Ky. PSC Oct. 28, 2025), Order at 35-37.

[81] To be clear, the Commonwealth has demonstrated its ability to successfully attract significant investment which both the General Assembly and the Governor believe will lead to greater economic success for Kentucky moving forward. However, the Commission must consider the landscape of large scale and energy intensive projects when brought to the Commission's attention. For example, while

uncertainty regarding electricity demand and shifting customer requirements necessitates a cautious approach that balances the equities.

The Commission remains a creature of statute, and its authority is limited to the powers granted it by the Kentucky General Assembly (General Assembly). As part of that mandate, the Commission must ensure that all rates meet the requirements of KRS Chapter 278, and while the Commission generally finds the proposed Stipulation appropriate, it is unable to approve the Stipulation without modification. In doing so, the Commission recognizes the good faith efforts of all parties involved in the Stipulation, as well as the dissenting views of non-joining intervening parties, in providing a full record of all material issues in this case. Therefore, as will be explained in detail below, the Commission approves the proposed Stipulation with modifications.

TEST PERIOD

KU used, as its forecasted test period, the 12-month period ending December 31, 2026.[82] Its base period is the 12-month period ending August 31, 2025.[83] The base period and test year period meet the requirements set in KRS 278.192 and 807 KAR 5:001, Sections 16(6), (7), and (8). None of the intervenors in this proceeding objected

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Kentucky is preparing for the addition of meaningful data center load on its system, the Oldham County project shows that any individual venture carries with it some uncertainty. See https://www.wlky.com/article/data-center-oldham-county-scrapped/65291482. Likewise, significant restructuring announced in late 2025 for the Blue Oval SK plant may well make the plant's demand uncertain in the short to medium term. See https://www.wymt.com/2025/12/15/1600-workers-be-laid-off-kentucky-manufacturing-plant/. For its part the labor report presented some positive indicators, though It also showed some decreases or static numbers in energy heavy sectors such as the manufacturing industry. See e.g. https://www.kentucky.gov/Pages/Activity-stream.aspx?n=EducationCabinet&prId=803. The purpose of this discussion is not to indicate the Commission's prognosis for the Kentucky economy and expected demand. However, the Commission cannot artificially blind itself to the realities on the ground when it comes to considering this, and other cases. Ratepayers require nothing less.

[82] Application at 7.

[83] Application at 7.

to the use of the test period. The Commission finds that it is reasonable to use the 12-month period ending December 31, 2026, as the test period in this case.

REVENUE REQUIREMENT

KU's application for a rate adjustment has evolved through a series of procedural filings that updated the test-period data and narrowed the issues in dispute. To clearly delineate the starting point for the Commission's adjustments, the procedural progression of the revenue requirement is summarized below.

In its application, KU requested an annual increase in electric revenues of approximately $226.3 million[84] based on a forecasted test period ending December 31, 2026. This request was predicated on a Return on Equity (ROE) of 10.95 percent[85] and included a depreciation study performed by John Spanos, which proposed depreciation rates resulting in a significant increase in depreciation expense.[86]

On August 25, 2025, KU filed a supplemental response to correct data identified during the discovery process. These updates to the forecasted test period reduced the calculated revenue deficiency. The electric revenue deficiency decreased by $6.2 million to a revised total of $220.1 million.[87] The primary driver for this $6.2 million total decrease was the inclusion of previously omitted Non-Executive Long-Term Incentive Compensation (LTI) totaling $1.9 million increase and corrections included updated computer software and IT project depreciation and cost allocations between KU and

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[84] Application at 8.

[85] Direct Testimony of Dylan D'Ascendis (D'Ascendis Direct Testimony) (filed May 30, 2025) at 68.

[86] Application at 10 and 15.

[87] Aug. 25, 2025 Supplemental Filing, Item 54.

LG&E totaling $6.1 million decrease, as well as updated vegetation management expenses pro forma adjustments to operating revenue and expenses totaling $0.7 million decrease plus Updated calculation of AFUDC depreciation expense totaling $0.5 million decrease.[88] KU has other corrections which did not have a significant impact on the revenue deficiency that some of the important ones are updated Lewis Ridge Pumped Hydro project costs, updated Cane Run BESS project costs, updated regulatory asset - FAS 158 Pension, updated ADIT related to New Generation AFUDC accruals, and Updated New Generation Not in Service pro forma adjustment based on corrected Cane Run BESS ownership allocation.[89]

Pursuant to 807 KAR 5:001, Section 16(7)(o), KU filed a Base Period Update on October 15, 2025, to reflect actual results for the full base period. This update adjusted rate base, capital structure, and operating expenses to reflect actuals rather than forecasts. The Base Period update included the forecasted test year amounts from August 25, 2025 Supplemental Filing.

The Stipulation included a reduced annual revenue increase of $132.0 million, an ROE of 9.90 percent, and the withdrawal of the originally proposed depreciation rates in favor of retaining existing rates.[90] The Stipulation reduced the proposed revenue requirement increase for KU operations by approximately $90 million relative to KU's August 25, 2025 Supplemental Filing.[91]

[88] Aug. 25, 2025 Supplemental Filing, Item 54.

[89] Aug. 25, 2025 Supplemental Filing, Item 54.

[90] Stipulation Testimony at 7.

[91] Stipulation Testimony at 7.

Unless otherwise noted, the Commission adopts the Stipulation's adjusted revenue requirement of $132.0 million from the August 25, 2025 Supplemental Filing as the baseline for its review. The Commission applied specific adjustments to arrive at the final authorized revenue requirement. Where the Commission rejects portions of the Stipulation's adjustments (such as the vegetation management deferral) it reverts to the verified test-year levels established in the August 25, 2025 Supplemental Filing.

INCOME STATEMENT

Test Year Operating Revenues. In its initial application, KU forecasted $1,839,402,028 in operating revenues in the base period ending August 31, 2025.[92] KU then forecasted an increase to its operating revenues in the amount of $28,908,572 to arrive at a test year level of operating revenues of $1,868,309,993.[93] However, on August 25, 2025, KU amended its application through a supplemental filing, which effectively increased its test year total operating revenues to $1,868,310,600.[94] To justify the increase in test year operating revenues, KU and LG&E created an electric load forecast for their 2025 Business Plan and revised their load forecast for their late February 2025 application for Certificates of Public Convenience and Necessity (CPCN) to account for increased amounts of expected data center load growth.[95] After the revisions made to the load forecast, KU's total retail calendar-adjusted electric sales increased by 596 GWh (3.3 percent) from the base period to the forecasted test period, and total customers would

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[92] KU's Response to Staff's First Request, Item 54, Schedule C-1.

[93] August 25, 2025 Supplemental Filing, Item 54, Schedule C-1.

[94] August 25, 2025 Supplemental Filing, Item 54, Schedule C-1.

[95] Direct Testimony of Charles Schram (Schram Direct Testimony) at 6.

increase by 4,699 (0.9 percent) from the base period to the forecasted test year.[96] No intervenors took issue with KU's forecasted load growth and forecasted customer count during the proceeding.

In its Base Period Update, filed on October 15, 2025, KU updated its base period operating revenues to reflect its actual revenues from the period of September 1, 2024 to August 31, 2025. This adjustment increased KU's base period operating revenues by $10,689,298 to arrive at a base period level of operating revenues of $1,850,091,326.[97] In the Base Period Update, KU left the test period level of operating revenues unchanged at $1,868,310,600, effectively lessening the increase in operating revenues from the base period to the forecasted test period.[98]

The proposed Stipulation in this proceeding resulted in no changes to KU's forecasted load growth, customer count, or operating revenues. As such, the information was accepted as part of the catch all provision of the Stipulation.

Having considered the record and being otherwise sufficiently advised, the Commission finds that the proposed Stipulation needs no modification to account for KU's forecasted test year operating revenues, load growth, or customer count. The Commission finds that KU's forecasted test year operating revenues are based on reasonable methodology that is consistent with how KU has forecasted its test-year revenues in its past rate cases. The Commission further finds that KU's projected customer growth in the forecasted test year is reasonable and consistent with historical

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[96] Schram Direct Testimony at 12.

[97] Base Period Update (filed Oct. 15, 2025), KU Base Period Update Attachment to Tab 54, Schedule C-1.

[98] Base Period Update, KU Base Period Update Attachment to Tab 54, Schedule C-1.

growth trends. KU's projected load forecast is based on known and measurable changes that are coming to KU's service territory. For those reasons, the Commission finds that KU's test-year level of operating revenues should be accepted as filed and amended through the supplemental filing.

Revenue Normalization Adjustments

In its application, KU proposed several adjustments to normalize its forecasted test year operating revenue from the base year period to remove the effects of KU's electric rate mechanisms.[99] These adjustments were uncontested by any of the intervenors. The Commission finds that several of the proposed adjustments are reasonable and should be accepted without change. Shown below are the adjustments that KU filed on October 15, 2025, as updated through the base period.

Demand Side Management (DSM) Mechanism. In its application, KU proposed to eliminate $22,999,160 in total operating revenues from base rates in the forecasted test year for the revenues that are currently recovered through KU's DSM mechanism.[100] In its August 25, 2025 Supplemental Filing, KU updated this adjustment to $22,999,172.[101] The Commission finds that the August 25, 2025 updated adjustment should be accepted without change as it follows standard regulatory accounting procedures and avoids inflating KU's projected revenues in base rates to account for the revenues recovered through its DSM mechanism.

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[99] Direct Testimony of Andrea M. Fackler (Fackler Direct Testimony) at 20.

[100] Application, Tab 57, Schedule D-2.

[101] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule D-2F.

Environment Cost Recovery (ECR) Mechanism. In its application, KU proposed to eliminate $89,531,818 of operating revenues attributable to the ECR mechanism.[102] In its August 25, 2025 Supplemental Filing, KU updated this adjustment to $89,488,600.[103] The Commission finds that the August 25, 2025 updated adjustment should be accepted without change, as it follows standard regulatory accounting procedures and avoids inflating KU's revenue to account for the revenues recovered through its ECR mechanism.

Out of System Sales. In its application, KU proposed an adjustment to reflect the removal of jurisdictional operating revenues by $1,332,015 to account for environmental compliance costs allocated to off-system and intercompany sales.[104] In its August 25, 2025 Supplemental Filing, KU updated this adjustment to $1,331,374.[105] This adjustment ensures that costs recovered through base rates are properly distinguished from those recovered via the environmental surcharge for off-system and intercompany sales. For this reason, the Commission finds that KU's August 25, 2025 updated adjustment to remove the revenues allocated to off-system and intercompany sales should be accepted without change.

Fuel Adjustment Clause (FAC). In its application, KU proposed to eliminate $5,175,030 in operating revenues that are recoverable through its FAC mechanism from the forecasted test period, consistent with past Commission practice.[106] In KU's August

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[102] Application, Tab 57, Schedule D-2.

[103] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule D-2F.

[104] Application, Tab 57, Schedule D-2.1.

[105] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule D-2.1.

[106] Application, Tab 57, Schedule D-2.

25, 2025 Supplemental Filing, this adjustment was unchanged.[107] This adjustment ensures that revenues recovered through base rates are properly distinguished from those recovered via the FAC mechanism. For this reason, the Commission finds that KU's adjustment to remove the revenues recoverable through its FAC mechanism should be accepted without change.

Off-System Sales (OSS). In its application, KU proposed to remove $12,760,963 in operating revenues related to OSS.[108] In KU's August 25, 2025 Supplemental Filing, this adjustment was unchanged.[109] Because these amounts are shared between customers and KU via a separate OSS adjustment clause, they must be removed from the test period to avoid duplicative recovery. For this reason, the Commission finds that KU's adjustment to remove the revenues related to its off-system sales should be accepted without change.

Operations Expense Normalization Adjustments

In its initial application, KU also made normalization adjustments for some of its operating expenses, including removing the expenses associated with its mechanisms that recover costs separately from base rates. The following adjustments went largely uncontested by all parties throughout the case record. Further, no intervenors provided testimony supporting or rejecting KU's proposed normalization adjustments.

DSM Mechanism Expenses. In its initial application, in conjunction with KU's adjustment to remove the revenues that are recoverable through its DSM mechanism,

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[107] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule D-2F.

[108] Application, Tab 57, Schedule D-2.

[109] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule D-2F.

KU also proposed a corresponding adjustment to remove the test year expenses that are recoverable through its DSM mechanism in the amount of $22,801,878.[110] In its August 25, 2025 Supplemental Filing, KU updated this adjustment to $22,801,881.[111] Much like the adjustment to remove the revenues recoverable through KU's DSM mechanism, the Commission finds that the August 25, 2025 updated adjustment should be approved without change as it follows standard regulatory accounting procedures and avoids inflating KU's projected operations' expenses in base rates to account for the expenses recovered through its DSM mechanism.

ECR Mechanism Expenses. In its application, in conjunction with KU's adjustment to remove the revenues that are recoverable through its ECR mechanism, KU also made a corresponding adjustment to remove the test year expenses that are recoverable through its ECR mechanism in the amount of $42,861,121.[112] In its August 25, 2025 Supplemental Filing, KU updated this adjustment to $42,871,904.[113] Much like the adjustment to remove the revenues recoverable through KU's ECR mechanism, the Commission finds that the August 25, 2025 updated adjustment should be approved without change, as it follows standard regulatory accounting procedures and avoids inflating KU's test-year operating expenses to account for the expenses recovered through its ECR mechanism.

[110] Application, Tab 57, Schedule D-2.

[111] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule D-2F.

[112] Application, Tab 57, Schedule D-2.

[113] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule D-2F.

Out of System Sales Expenses. In its application, in conjunction with KU's adjustment to remove the revenues to account for environmental compliance costs allocated to off-system and intercompany sales, KU also made a corresponding adjustment to remove the test year expenses allocated to off-system and intercompany sales related to environmental compliance costs in the amount of $332,338.[114] In its August 25, 2025 Supplemental Filing, KU updated this adjustment to $332,178.[115] Much like the adjustment to remove the revenues allocated to off-system and intercompany sales, the Commission finds that the August 25, 2025 updated adjustment should be approved without change, as this adjustment ensures that costs recovered through base rates are properly distinguished from those recovered via the environmental surcharge.

FAC Expenses. In its application, in conjunction with KU's adjustment to remove the revenues that are recoverable through its FAC mechanism, KU also made a corresponding adjustment to remove the test year expenses that are recoverable through its FAC mechanism in the amount of $5,175,030.[116] In KU's August 25, 2025 Supplemental Filing, this adjustment was unchanged.[117] Much like the adjustment to remove the revenues recoverable through KU's FAC mechanism, the Commission finds that this adjustment should be approved without change, as this adjustment ensures that KU's forecasted expenses in the test year are established on a normalized basis.

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[114] Application, Tab 57, Schedule D-2.1.

[115] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule D-2.1.

[116] Application, Tab 57, Schedule D-2.

[117] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule D-2F.

OSS Expenses. In its application, in conjunction with KU's adjustment to remove the revenues related to its off-system sales, KU made a corresponding adjustment to remove the expenses related to its off-system sales in the amount of $12,010,701.[118] In KU's August 25, 2025 Supplemental Filing, this adjustment was unchanged.[119] Much like the adjustment to remove the revenues related to KU's OSS, the Commission finds that this adjustment is reasonable and should be approved without change, as it ensures that KU's forecasted expenses in the test year are not being recovered twice, through base rates and through KU's OSS mechanism.

Advertising Expenses. In its application, KU proposed to remove $705,858 in operating expenses related to promotional advertising.[120] In KU's August 25, 2025 Supplemental Filing, this adjustment was unchanged.[121] Consistent with 807 KAR 5:016, Section 1, the Commission finds that promotional advertising expenses are not reasonable to be recovered from ratepayers. For this reason, the Commission finds that KU's adjustment to remove the expenses related to promotional advertising should be accepted without change.

New Generation Not in Service. In its application, KU proposed an adjustment to remove the operating expenses related to AFUDC debt and equity accruals for Mercer County Solar, since the plant is now expected to be placed in service in 2027, outside of the scope of the test year. The effect of this adjustment is an increase of $10,250,907 in

[118] Application, Tab 57, Schedule D-2.

[119] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule D-2F.

[120] Application, Tab 57, Schedule D-2.1.

[121] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule D-2.1.

operating expenses, including depreciation and AFUDC accruals, associated with new generation projects not yet in service or experiencing delays.[122] In its August 25, 2025 Supplemental Filing, KU updated this adjustment to $10,936,270.[123] In this instance, since Mercer County Solar is not expected to be placed in service until 2027, the Commission finds that the August 25, 2025 updated adjustment to remove the expenses associated with its AFUDC debt and equity accruals is reasonable and should be accepted without change.

AMI Savings Regulatory Liability. KU proposed to remove operating expenses by $1,970,603 to reflect the accelerated return of AMI project savings to customers.[124] In KU's August 25, 2025 Supplemental Filing, this adjustment was unchanged.[125] Having reviewed the record and being otherwise sufficiently advised, the Commission finds that this adjustment should be approved without change, as it properly reflects the benefits that AMI brings to KU's ratepayers.

Revolving Credit Facility Fees. KU proposed to increase operating expenses by $241,610 to account for higher fees associated with KU's expanded borrowing capacity.[126] In KU's August 25, 2025 Supplemental Filing, this adjustment was unchanged.[127] This adjustment reflects the impact of the extension and expansion of its

[122] Application, Tab 57, Schedule D-2.1.

[123] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule D-2.1.

[124] Application, Tab 57, Schedule D-2.1.

[125] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule D-2.1.

[126] Application, Tab 57, Schedule D-2.1.

[127] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule D-2.1.

revolving credit facilities in early 2025.[128] Having reviewed the record and being otherwise sufficiently advised, the Commission finds that this adjustment should be approved without change, as the adjustment is based on known and measurable changes to KU's revolving credit facility fees.

Operations and Maintenance Expenses

The following adjustments to the test year expenses were proposed by the Attorney General/KIUC. The list also includes adjustments addressed in the Stipulation.

Payroll and Related Expenses. KU proposed total payroll costs of $269,360,973 in its application.[129] From the application through KU's base period update, KU's test year total payroll costs remained unchanged.[130] KU explained that the payroll expense ratios will change based on the amount of labor charged to 26 capital projects and that the level of capital spending fluctuates from year to year and the ratios for the test year are well within the ranges KU expects and has previously experienced.[131]

Prior to the Stipulation, the Attorney General/KIUC argued that, even though projected total payroll costs appear reasonable in the test year, the percentage of those costs expensed, not deferred, and capitalized is excessive.[132] The Attorney General/KIUC stated that the increases in the levels of payroll expense are high, exceeding the expected 3.0 percent or less per year in merit-based pay increases.[133] The

[128] Fackler Direct Testimony at 23.

[129] Application, Tab 60, Attachment 1 at 1.

[130] Base Period Update (filed October 15, 2025), Tab 60, Schedule G-1.

[131] KU's response to the Attorney General/KIUC's First Request, Item 70(e).

[132] Futral Direct Testimony at 11.

[133] Futral Direct Testimony at 12.

Attorney General/KIUC originally recommended that the Commission utilize the same payroll expense ratios in the test year as actually incurred during 2024, and reduce the payroll expense in the test year proportionately, as KU had offered no valid reason why the expense ratio should be increased, especially when capital expenditures are increasing so significantly and not decreasing.[134] This recommendation would result in a reduction in KU's jurisdictional payroll and related expenses of $9,671,127.[135] The Attorney General/KIUC explained that these calculations assume a payroll tax expense of 7.5 percent.[136] After gross-ups, the effects are a reduction in KU's revenue requirement of $9,712,073.[137]

In its rebuttal testimony, KU explained that, while the Attorney General/KIUC correctly noted that the payroll expense ratios in the test year are higher than those recorded in 2023 and 2024, the increase is both reasonable and explainable when adjusted for an apples-to-apples comparison.[138] KU stated that the higher ratio reflects operational needs and accounting treatment differences between the test year and prior years.[139] KU argued that using a historic ratio ignores the dynamic nature of labor allocation and the evolving operational demands of KU, that the test year projections are

[134] Futral Direct Testimony at 12.

[135] *See* Futral Direct Testimony at 15; AG-KIUC Recommended Revenue Requirement KU (filed September 9, 2025), Payroll Costs tab. The Commission notes that this proposed adjustment was rounded to the millions in the Attorney General/KIUC's expert witness testimony. In order to get the whole number for this proposed adjustment, the Commission multiplied the Attorney General/KIUC's originally proposed adjustment by one million.

[136] Futral Direct Testimony at 15.

[137] Futral Direct Testimony at 15-16.

[138] Metts Rebuttal Testimony at 1.

[139] Metts Rebuttal Testimony at 1-2.

based on detailed internal budgeting and reflect anticipated workload distribution, and that applying a prior year's ratio would understate the true cost of providing reliable service.[140]

The Stipulation did not include the Attorney General/KIUC's adjustment to reduce payroll and related expenses. However, through the Stipulation's catch all provision, the Stipulation provides that KU's test year payroll costs be accepted as filed.[141]

Having considered the record and being otherwise sufficiently advised, the Commission finds that the Attorney General/KIUC's proposed adjustment to KU's forecasted payroll expenses should be denied as KU's forecasted payroll and payroll-related expenses are reasonable and supported by known and measurable changes. The Commission finds that KU provided sufficient evidence to support its increase to the payroll expense ratios, as it is based on both operational needs and accounting treatment differences.

<u>401(k) Expense</u>. In its initial application, KU proposed an increase to its Employee Benefits expense by $9,512,140 to arrive at a test year expense level of $57,923,004.[142] In its August 25, 2025 supplemental filing, and in its Base Period update, KU's test year level of Employee Benefits expense remained unchanged.[143] In response to discovery, KU stated that it included $933,078, jurisdictionally, in retirement plan expense related to matching contributions made to employees' 401(k) retirement plans who are also

[140] Metts Rebuttal Testimony at 3.

[141] Amended Stipulation, Section 11.1.

[142] Application, Tab 60 at 1.

[143] Base Period Update (filed October 15, 2025), Tab 60, Schedule G-1.

participants in a defined benefit pension plan for both its direct employees and expenses allocated from LKS Services Company and PPLS Services Company (PPLS).[144]

Prior to the Stipulation, the Attorney General/KIUC recommended reducing KU's 401(k) expense by $933,078 based on Commission precedent in which the Commission denied recovery of retirement expenses for which a utility made contributions to both a defined benefit pension plan and a 401(k) plan.[145] In Case No. 2018-00294, the Commission noted that, for ratemaking purposes, it is not reasonable to include KU's contributions to both the defined benefit and the 401(k) defined contribution plan as the KU employees participating in the defined benefit plan enjoy generous retirement plan benefits, making the defined contribution plan amounts excessive for ratemaking purposes.[146]

KU disagreed with the Attorney General/KIUC's reasoning for their recommendation. KU argued that, after the Orders were issued in Case No. 2018-00249 and Case No. 2018-00250, KU filed its 2020 Rate Case (Case No. 2020-00349[147]), where its filed position on this issue was that no disallowance of 401(k) contribution costs should be made for those employees also participating in a defined benefit pension plan.[148] KU further argued that, in Case No. 2020-00349, a Stipulation and Recommendation was

[144] KU's Response to the Attorney General/KIUC's First Request, Item 86.

[145] Direct Testimony of Lane Kollen (Kollen Corrected Direct Testimony) at 57.

[146] Case No. 2018-00294, *Electronic Application of Kentucky Utilities Company for an Adjustment of Electric Rates*, April 30, 2019, Order at 17.

[147] Case No. 2020-00349, *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* (filed Nov. 25, 2020), Stipulation Testimony Exhibit KWB-1 at Section 5.9.

[148] Poplaski Rebuttal Testimony at 9.

reached, and a disallowance of the 401(k) costs was not one of the specific compromised amounts leading to the stipulated and recommended revenue requirement, which was accepted by the Commission with modifications by Order of June 30, 2021.[149]

The Signing Parties to the Stipulation agreed to include the Attorney General/KIUC's original adjustment to remove all 401(k) expenses for employees who are also covered under a defined benefit pension plan.

Having considered the record and being otherwise sufficiently advised, the Commission finds that the Stipulation adjustment to account for the 401(k) matching contributions made by KU to its employees who are also eligible for the defined benefit pension plan is reasonable and should be accepted. The Commission finds that the test year level of KU's Employee Benefits expense should be reduced by $933,078 to reflect 401(k) matching contributions made by KU to its employees who are also eligible for the defined benefit pension plan. This adjustment reduces KU's base revenue requirement by $937,029.

Executive Compensation. The following chart shows the compensation of KU's officers during the base period as well as the forecasted test period, according to the application.[150]

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[149] Poplaski Rebuttal Testimony at 9-10.

[150] Application, Tab 60, Attachment 2; Base Period Update.

Kentucky Utilities Company
Case No. 2025-00113
Total Officer Compensation (Salary and Other Compensation)
For the Base Period and the Forecasted Test Period

Job Title	Base Period Total Compensation	Base Period Total Compensation, as Updated	Forecasted Test Period Total Compensation
President (LKE) & CBDO	$ 1,631,090	$ 1,631,015	$ 1,660,252
VP Communications & Corporate Responsibility (LKE)	427,768	426,678	-
VP COO (LKE)	654,022	653,947	676,895
VP - Customer Service (LKE)	495,644	489,131	517,089
VP - Electric Distribution (LKE)	546,276	546,301	578,847
VP - Energy Supply and Analysis (LKE)	595,752	593,453	495,896
VP - External Affairs	381,311	381,236	398,025
VP - Gas Operations (LKE)	498,897	498,897	526,189
VP - Generation (LKE)	292,629	556,550	544,462
VP - State Regulation and Rates	422,886	422,900	435,968
VP - Transmission	557,371	557,371	574,863
Average of All Officers	$ 591,241	$ 614,316	$ 640,849

KU noted its forecast assumed an annual salary increase of three percent.[151] KU explained that, of the total salary and other compensation, 20.6 percent is allocated pursuant to the cost of providing service to KU rate payers.[152] Other compensation includes cash-based short-term incentives and stock based long-term incentives calculated at target.[153] KU noted that none of the incentive pay is included in the cost of service.[154]

As part of its application, KU provided a total remuneration study conducted by Willis Tower Watson that found that KU's compensation and benefit levels are within the range of market competitiveness, and the short-term and long-term at-risk compensation programs are consistent with market practices of utility peers.[155]

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[151] Application, Tab 60, Attachment 2.

[152] Application, Tab 60, Attachment 2.

[153] Application, Tab 60, Attachment 2.

[154] Application, Tab 60, Attachment 2.

[155] Application, Tab 60, Attachment 3.

Determining the level of Executive Compensation was extremely challenging in this proceeding. In Staff's First Request, KU was asked to provide the following:[156]

> Separately for electric and gas operations, provide, in the format provided in Schedule K, the following information for LG&E's compensation and benefits, for the three most recent calendar years and the base period. Provide the information individually for each corporate officer and by category for Directors, Managers, Supervisors, Exempt, Non-Exempt, Union, and Non-Union Hourly. Provide the amounts, in gross dollars, separately for total company operations and jurisdictional operations.[157]

This request asked for regular salary or wages, overtime pay, and as well as other benefits. KU's response was not provided in the Schedule K format detailed by Commission Staff, which made it difficult to determine this information per executive officer. KU explained that the KU budgeting process does not allow KU to provide the data requested in the exact employment types (Officers, Directors, etc.) requested in the question; however, all labor dollars were provided in an attachment.[158] KU further explained that it provided the information by the employment types requested (Officers, Directors, etc.), and KU has also provided the wage and salary information as reported on W-2's for each group requested for 2022-2024 and the base period through February, 2025 by those employment type.[159] KU provided updated information in Schedule K format as requested in Staff's Post-Hearing Data Request.[160] KU explained that the

[156] Application, Tab 60, Attachment 3.

[157] Staff's First Request, Item 41.

[158] KU's Response to Staff's First Request, Item 41 a-o.

[159] KU's Response to Staff's First Request, Item 41 a-o.

[160] KU's response to Staff's Post-Hearing Request, Item 52.

individual corporate officers listed in the response receive a single paycheck, and they do not receive compensation for “total company operations” separate from their compensation for “total jurisdiction operations.”[161] The Commission would not expect corporate officers to receive separate payments and the request did not ask for separate payment amounts, only separate accounting treatment between total company and jurisdictional amounts. The separation of allocated expenses is requested repeatedly throughout the proceeding yet only seemed to be a challenge for KU when it came to compensation of officers. The explanation for the error in responding to the compensation information lacks credibility when compared to KU’s ability to otherwise separate allocated costs between total costs and jurisdictional costs.

Joint Intervenors highlighted that KU with LG&E paid nearly $6.6 million in executive compensation to 11 officers in 2024 and the amount increased to approximately [redacted] in 2025.[162] Joint Intervenors stated that LG&E and KU do not appear to have provided the salaries for the Executive VP, Engineering, Construction and Generation, PPL Services Corporation or the Vice President - Financial Strategy and Chief Risk Officer, PPL Services Corporation, two lead witnesses in this case.[163] Joint Intervenors stated that

[redacted]

[161] KU’s Response to Staff’s Post-Hearing Request, Item 52(e).

[162] Joint Intervenors’ Brief at 19.

[163] Joint Intervenors’ Brief at 20.

Further confusion arose because, there appeared to be discrepancies in the titles for witnesses from the testimony[164] to the affidavits, and the compensation information provided by KU does not contain enough information to reconcile professional titles with salaries. Joint Intervenors raise legitimate concerns that the Commission shares. The Commission believes that the way KU has presented its executive compensation information makes it extremely difficult to determine the total compensation that KU pays for its executive officers. For example, the total compensation of John Crockett, who is the President of Kentucky Utilities Company and Louisville Gas and Electric Company, and Senior Vice President and Chief Development Officer, PPL Services Corporation,[165] in the base period, is $1,631,090, and in the base period update the amount was updated to $1,631,015.[166] However, the total compensation and benefits paid by KU to John Crockett in Schedule K is listed as $270,172, and the total compensation and benefits paid by LKS is $2,526,385.[167] There appears to be no reconciliation between what was provided in Tab 60 of its application and base period update and what was provided in response to Staff's Post-Hearing Request.[168] This appears to be an effort to deliberately make it difficult for the Commission to determine how much KU is providing in total compensation and benefits for executives as well as how KU forecasted these amounts. The Commission expects KU to respond as requested to requests for information,

[164] See KU's Response to Staff's Post-Hearing Request, Item 29. Examples of omitted titles included the titles of Julissa Burgos and Tom Reith; and KU stated in certain places it was "unwieldly" to list all of this information in relation to titles and roles.

[165] KU's Response to Staff's Post-Hearing Request, Item 29.

[166] Application, Tab 60, Attachment 2; Base Period Update.

[167] KU's Response to Staff's Post Hearing Request, Item 52.

[168] Application, Tab 60, Attachment 2; Base Period Update.

especially in the initial request which is standard across all general rate cases. The Commission is putting KU on notice that, in future rate cases, KU is expected to provide clear and reconcilable information when responding to expense requests including executive compensation. The applicant bears the burden of proof to justify expenditures and the lack of transparency in providing information to the Commission promotes a lack of credibility, particularly with an expense item that can be as adversarial as executive compensation. Lack of clarity in jurisdictional expenses compared to total expenses also calls into question the verity of the allocation of other expenses. The Commission notes that should KU expense allocations be difficult to follow in future cases, those expense allocations may be diminished or disallowed entirely on the basis that KU has not met its burden of proof.

In addition, the Commission reviewed the most recent annual report on file.[169] Unlike other investor-owned utilities,[170] KU does not list its executive salaries as required in "Report name, title and salary for each executive officer whose salary is $50,000 or more" section of the filing. This is an omission in the filing and should be corrected going forward. The Commission expects KU to include the required information in its upcoming annual report filing for 2025. As noted many times by the Commission, executive compensation and the compensation of individual executive employees are not entitled to confidential treatment in the interest of transparency for the rate paying public.[171]Long-

[169] *Annual Report of KU to the Public Service Commission for the Year Ending December 31, 2024* at 12. The report reads "[s]alary information for all officers is on file in the office of the respondent."

[170] *See Annual Report of Duke Energy to the Public Service Commission for the Year Ending December 31, 2024* at 12.

[171] The Commission has a long precedent of not granting confidential treatment for executive compensation. *See* Case No. 2012-00221, *Application of Kentucky Utilities Company for an Adjustment of*

Term Incentive Compensation. KU offers three incentive compensation programs: the Short-Term Incentive Plan (STI), the Customer Services Operations and Support Contact Center Incentive Plan, and the Long-Term Incentive Plan (LTI).[172] In response to discovery, KU stated that the company-wide incentive plan is PPL's STI program; however, managers, directors, and senior level individual contributors may also participate in the LTI.[173] KU also stated that it included $27,342 in the forecasted test period for KU employees but erroneously excluded $1,989,814 allocated from PPLS.[174]

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its Electric Rates (Ky. PSC Sept. 11, 2013); Case No. 2014-00371, *Application of Kentucky Utilities Company for an Adjustment of its Electric Rates* (Ky PSC Jan 20, 2016); Case No. 2015-00418, *Application of Kentucky-American Water Company for an Adjustment of Rates* (Ky PSC Aug. 31, 2016); Case No. 2017-00321, *Electronic Application of Duke Energy Kentucky, Inc. For: 1) An Adjustment of the Electric Rates; 2) Approval of an Environment Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All other Required Approvals and Relief* (Ky. PSC June 12, 2018); Case No. 2018-00294, *Electronic Application of Kentucky Utilities Company for an Adjustment of its Electric Rates* (Ky. PSC Oct. 8, 2019); Case No. 2018-00295, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates* (Ky. PSC Oct. 8, 2019); Case No. 2019-00268, *Application of Knott County Water and Sewer District for an Alternative Rate Adjustment* (Ky. PSC Dec. 3, 2019); 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 May 4, 2020); Case No. 2020-00290, *Electronic Application of Bluegrass Water Utility Operating Company, LLC for an Adjustment of Rates and Approval of Construction* (Ky. PSC Dec. 27, 2021); Case No. 2020-00349, *Electronic Application of Kentucky Utilities Company for an Adjustment of 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 Subcredit* (Ky. PSC Dec. 7, 2021); Case No. 2020-00350, *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 One-Year Surcredit* (Ky. PSC Dec. 7, 2021); Case No. 2021-00183, *Electronic Application of Columbia Gas of Kentucky, Inc. for an Adjustment of Rates; Approval of Depreciation Study; Approval of Tariff Revision; Issuance of a Certificate of Public Convenience and Necessity; and Other Relief* (Ky. PSC Oct. 5, 2021); Case No. 2021-00185, *Electric Application of Delta Natural Gas Company, Inc. for an Adjustment of its Rates and a Certificate of Public Convenience and Necessity* (Ky. PSC Dec. 8, 2021).

[172] KU's Response to the Attorney General/KIUC's First Request, Item 47.

[173] KU's Response to the Attorney General/KIUC's First Request, Item 46.

[174] KU's Response to the Attorney General/KIUC's First Request, Item 46; KU's Response to the Attorney General/KIUC's Second Request, Item 7(b).

KU stated that PPL's LTI is an at-risk form of compensation designed to reward employees for contributing to the company's long-term success and is provided in the form of restricted stock units (RSUs) that vest over a multi-year period.[175] KU argued that RSUs are forfeited if an employee separates from the organization before the vesting date outside of a qualified retirement, death, or disability, which supports talent retention initiatives.[176]

On August 25, 2025, KU updated its forecasted expenses in the test year, which made a material change to its base revenue requirement.[177] Of those changes, KU stated that it updated its Non-Executive LTI to include the omitted $1,989,814 in the forecasted test period for the LTI costs allocated from PPLS.[178]

Prior to the Stipulation, the Attorney General/KIUC recommended disallowing the LTI plan incentive compensation expense awarded in the form of PPL RSUs.[179] The Attorney General/KIUC argued that the LTI payments are made in the form of stock grants of PPL stock, and thus, 100 percent of the LTI plan compensation expense is tied to reaching the financial performance of PPL including its stock price.[180] The Attorney General/KIUC further argued that the Commission has a long-standing practice of disallowing such expenses and has historically disallowed all incentive compensation expenses from the revenue requirement that were incurred to incentivize the achievement

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175 KU's Response to the Attorney General/KIUC's First Request, Item 47.

176 KU's Response to the Attorney General/KIUC's First Request, Item 47.

177 August 25, 2025 Supplemental Filing, Item 54 at 1.

178 August 25, 2025 Supplemental Filing, Item 54 at 2.

179 Direct Testimony of Randy Futral (Futral Direct Testimony) at 28.

180 Futral Direct Testimony at 26.

of shareholder goals as measured by financial performance, not incurred to incentivize the achievement of customer and safety goals.[181]

In rebuttal testimony, KU argued that the purpose and reason for the LTI plan is to retain employees and supported that notion by stating that the RSUs issued to an employee do not vest upon issuance and instead only fully vest if the employee remains with the company three years after they are issued.[182] KU further argued that, unlike incentive compensation dependent on or tied to financial measures, for RSUs issued pursuant to the LTI plan, the only prerequisite to the award of RSUs is tenure with the company, making the LTI plan payments solely a time-based measure rather than a financial measure.[183]

The Stipulation did not make an adjustment to address the Attorney General/KIUC's concerns regarding the RSUs. As such, the Stipulation accepted the pro forma expenses for LTI as contained in the August 25, 2025 Supplemental Filing.

Having considered the record and being otherwise sufficiently advised, the Commission finds that the Stipulation should be modified to make an adjustment related to KU's incentive compensation. While KU contended that the total compensation of its employees, inclusive of the LTI plan, is reasonable and based on the market,[184] the Commission finds that the Attorney General/KIUC's initial proposed adjustment to remove incentive compensation paid out in the form of PPL RSUs should be accepted.

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[181] Futral Direct Testimony at 27.

[182] Rebuttal Testimony of Vincent Poplaski (Poplaski Rebuttal Testimony) at 3.

[183] Poplaski Rebuttal Testimony at 4.

[184] Poplaski Rebuttal Testimony at 2.

The Commission has historically disallowed recovery of incentive compensation tied to the financial performance of the company,[185] and while the RSUs are in part awarded based on length of employment, the Commission is not moved by KU's position that incentive compensation paid out in the form of RSUs is solely a time-based measure. While RSUs do not fully vest upon issuance, the mere fact of an employee receiving PPL stock incentivizes that employee entirely to perform more work at the benefit of PPL shareholders, not KU's customers. For those reasons, the Commission finds that the entirety of KU's LTI plan expense in the forecasted test year should be removed, consistent with Commission precedent. The resulting revenue requirement impact is a reduction of $1,911,340. This reduction creates a corresponding decrease of $150,341 to KU's forecasted test year Payroll Tax Expense, which results in a revenue requirement reduction of $150,978.

Edison Electric Institute (EEI) and Related Dues. In its initial application, KU included $1,306,271 in its base period ending August 31, 2025, and $1,077,037 in its forecasted test year for organization membership dues with a reduction of $159,367 and $155,319, respectively to account for dues that are non-recoverable due to lobbying or political activities.[186] Through its Base Period Update, KU's test year Membership Dues expense remained unchanged.[187] In response to discovery, KU stated that, of the 17

[185] Case No. 2023-00159, *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) A Securitization Financing Order; and (5) All Other Required Approvals and Relief* (Ky. PSC Jan. 19, 2024), Order at 26; Case No. 2013-00148, *Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications* (Ky. PSC Apr. 22, 2014), Order at 20.

[186] Application, Tab 59, Schedule F-1 at 3.

[187] Base Period Update, Tab 59, Schedule F-1.

organizations, KU pays dues to, only four engage in covered activities, such as lobbying, advertising, marketing, legislative policy research, and regulatory policy research.[188] Those organizations are Edison Electric Institute (EEI), Utility Solid Waste Activities Group (USWAG), Utilities Technology Council, and Waterways Council.[189] In the original filing, of the four organizations that KU stated engaged in, for rate making purposes, disallowed activities, KU only made the corresponding adjustment to remove the non-recoverable portion of the expense for one organization, EEI.[190]

In response to discovery, KU stated that the following adjustments should have been made to its Organization Membership Dues expenses to remove the non-recoverable portion of its Membership Dues expense:

- Utility Solid Waste Activities Group- $(401)
- Utilities Technology Councill- $(532)
- Waterways Council- $(2,864)[191]

The Attorney General/KIUC recommended removing all EEI, USWAG, Utilities Technology Council, and Waterways Council dues in the test year in accordance with Commission precedent.[192] Citing KU's most recent base rate case, Case No. 2020-00349, as well as more recent proceedings in which this same issue was addressed, Case No. 2024-00276,[193] the Attorney General/KIUC claimed that no circumstances have

[188] KU's Response to the Attorney General/KIUC's First Request, Item 3.

[189] KU's Response to the Attorney General/KIUC's First Request, Item 3.

[190] Application, Tab 59, Schedule F-1 at 3.

[191] KU's Response to the Attorney General/KIUC's First Request, Item 3.

[192] Futral Direct Testimony at 32.

[193] Case No. 2024-00276, Aug. 11, 2025 Order at 27.

changed pertaining to the issue regarding a utility's Membership Dues Expense since KU's last base rate case.[194] Further arguing this point, the Attorney General/KIUC claimed that KU has provided no evidence of a direct ratepayer benefit from its membership in these trade organizations, and no evidence that ratepayer-provided dues are not used for legislative advocacy, regulatory advocacy, and/or public relations.[195]

In rebuttal, KU disagreed with the Attorney General/KIUC's recommendation to disallow recovery of the dues paid to organizations who engage in covered activities on the basis that organizations like EEI, USWAG, Utilities Technology Council, and Waterways Council support KU's ability to operate efficiently, stay informed on industry developments, and engage in collaborative efforts that benefit customers and the broader utility sector.[196] For example, KU stated that EEI membership provides a wide array of services that benefit customers such as mutual assistance, cyber and physical security, resilience programs, national key accounts program, industry collaboration and benchmarking, regulatory foresight, and clean energy initiatives.[197] However, in its rebuttal testimony, KU did not mention how membership in USWAG, Utilities Technology Council, and Waterways Council benefits its ratepayers.

In the Stipulation, the Signing Parties agreed to remove the dues KU paid to EEI, USWAG, Utilities Technology Council, and Waterways Council.[198] This stipulated adjustment removes the membership dues associated with the same organizations that

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[194] Futral Direct Testimony at 31-32.

[195] Futral Direct Testimony at 33.

[196] Rebuttal Testimony of Christopher Garrett (Garrett Rebuttal Testimony) at 29.

[197] Garrett Rebuttal Testimony at 30-31.

[198] Stipulation and Recommendation Section 2.2(F).

were included in the Attorney General/KIUC's original recommendation, which would reduce KU's Membership Dues expense by $531,194, or approximately $0.5 million (as listed in the Stipulation).[199]

Having considered the record and being otherwise sufficiently advised, the Commission finds that the Stipulation reduction of Membership Dues Expense for those organizations who engage in certain activities, such as lobbying, advertising, marketing, legislative policy research, and regulatory policy research, is appropriate. The Commission finds that the removal of KU's membership dues expenses related to organizations who engage in lobbying, advertising, marketing, legislative policy research, and regulatory policy research is consistent with Commission precedent.[200] Without knowing which costs comprise the percentage of dues attributable to covered activities, the Commission cannot find, with reasonable certainty, that these percentages are based on actual spending in all covered activities, rather than spending attributable to lobbying only. Further, while KU has established some benefits from its membership in EEI, it failed to establish how its membership in EEI explicitly benefits its ratepayers and failed to establish any benefits from its membership in organizations such as USWAG, Utilities Technology Council, and Waterways Council. The effect of this adjustment is a reduction to KU's Membership Dues Expense of $531,194 and a reduction to KU's base revenue requirement of $533,443.

<u>Reduce Miscellaneous Steam Power Expenses in Account 506</u>. In its initial application, KU included $27,045,006 (jurisdictional) in the base period ending August 31,

[199] Stipulation and Recommendation Section 2.2(F).

[200] Case No. 2025-00122, Dec. 16, 2025 Order at 31-32; Case No 2024-00276, Aug. 11, 2025 Order at 27.

2025, and $31,219,627 (jurisdictional) in test year expenses in Account 506.[201] This represented a $4,216,858 increase from the base period ending August 31, 2025, to the forecasted test period. Through its Base Period Update, filed on October 15, 2025, KU's test year level of Miscellaneous Steam Power expenses remained unchanged from its initial application.[202] KU stated that this increase was due to: higher environmental reagent expenses due to pricing increases; higher fees and permits in the test period driven by higher estimated Environmental Title V fees; and higher projected supplemental contractor expenses in the test period driven by projected wage increase escalations.[203]

Prior to the Stipulation, the Attorney General/KIUC stated that this amount is considerably higher than the actual amounts incurred for this account in recent years.[204] The Attorney General/KIUC pointed out that the expenses during the base period, in the amount of $27.045 million, were fairly consistent with the amounts incurred during the previous years.[205] The Attorney General/KIUC originally recommended that the Commission reduce the level of projected expenses in Account 506 unless KU provides all appropriate support in order to justify each of the large increases assumed to meet the known and measurable ratemaking standard.[206] The Attorney General/KIUC recommended that the projected expense amounts be based on the levels of expense in

[201] Application, Schedule C-2.1.

[202] Base Period Update, Tab 56, Schedule C-2.1.

[203] KU's Response to the Attorney General/KIUC's Second Request, Item 14(a).

[204] Futral Direct Testimony at 16.

[205] Futral Direct Testimony at 16.

[206] Futral Direct Testimony at 18.

the base year escalated by 3.6 percent for the effects of sixteen months of inflation.[207] This recommendation would result in a reduction in KU's jurisdictional expense of $3,201,001, and after gross-up, a reduction in KU's revenue requirement of $3,214,553.[208]

It its rebuttal testimony, KU argued that the projected increase in Account 506 is supported by known and measurable changes to commodities used in the generation process, environmental compliance costs and contractor rates.[209] KU explained that, while the historical price increases are supportive of the amounts used in base rates, the budgeting team also uses current contract pricing and estimated fuel surcharges calculated by the Fuels Department to prepare a more robust and accurate budget than simply depending upon historical increases.[210] For Title V annual expenses, KU applied an average inflationary increase to estimate costs in 2024 to 2026.[211]

The Stipulation did not include the Attorney General/KIUC's adjustment to reduce miscellaneous steam power expenses in Account 506. However, since this was not a compromised amount in the Stipulation, this expense falls under the Stipulations proposed "catch-all" provision, meaning that the Stipulation accepts KU's miscellaneous steam power expenses in Account 506 as filed in the application.

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[207] Futral Direct Testimony at 18.

[208] Futral Direct Testimony at 18; AG-KIUC Recommended Revenue Requirement KU (filed September 9, 2025), Various O&M Expenses Tab. The Commission notes that this proposed adjustment was rounded to the millions in the Attorney General/KIUC's expert witness testimony. In order to get the whole number for this proposed adjustment, the Commission multiplied the Attorney General/KIUC's originally proposed adjustment by one million.

[209] Metts Rebuttal Testimony at 4.

[210] Metts Rebuttal Testimony at 4-5.

[211] Metts Rebuttal Testimony at 5.

Having considered the record and being otherwise sufficiently advised, the Commission finds that KU's forecasted increase to miscellaneous steam power expenses is reasonable and supported by known and measurable changes to the pricing KU received in its operations. The Attorney General/KIUC's recommended adjustment is based on 16 months of inflation and not actual pricing increases. As such, the adjustment recommended by the Attorney General/KIUC is rejected.

Reduce Miscellaneous Transmission Expenses in Account 566. In its initial application, KU included $32,524,255 (jurisdictional) in the base period ending August 31, 2025, and $36,150,780 (jurisdictional) in test year expenses in Account 566.[212] This represented a $3,626,525 increase from the base period ending August 31, 2025 to the forecasted test period. Through its Base Period update, filed on October 15, 2025, KU's test year level of Miscellaneous Transmission expenses remained unchanged from its initial application.[213] KU stated that the increase was due to higher depancaking expense in the test year due to the projected increase in the Midwest Independent System Operator's (MISO) rate; higher Reliability Coordinator and Independent Transmission Operator contractual cost increases in the test year; higher substation administrative contract labor and material expenses in the test year higher North American Electric Reliability Corporation (NERC) fees; periodic ARC Flash expense occurring every five years, including the forward test year; and higher FAC-008 BES Walkdown expense in the test year.[214]

[212] Application, Tab 56, Schedule C-2.1 at 11.

[213] Base Period Update, Tab 56, Schedule C-2.1.

[214] KU's Response to the Attorney General/KIUC's Second Request, Item 14(d).

Prior to the Stipulation, the Attorney General/KIUC originally argued that this amount is considerably higher than the actual amounts incurred for this account in recent years.[215] The Attorney General/KIUC stated that the expenses during the base year were fairly consistent with the amounts incurred during the previous years, while the test year amounts represent significant increases over those base year levels.[216] The Attorney General/KIUC originally recommended that the Commission reduce the level of projected expenses in Account 566 unless KU provided all appropriate support in order to justify each of the large increases assumed to meet the known and measurable ratemaking standard.[217] The Attorney General/KIUC further recommend that the projected expense amounts be based on the levels of expense in the base year escalated by 3.6 percent for the effects of sixteen months of inflation.[218]

In its rebuttal testimony, KU explained that the increase is driven by externally imposed costs and compliance obligations, which KU has supported.[219]

The Stipulation did not include the Attorney General/KIUC's adjustment to reduce miscellaneous transmission expenses in Account 566. However, since this was not a compromised amount in the Stipulation, this expense falls under the Stipulation's proposed catch all provision.[220] As such, KU's expenses related to Account 566 – Miscellaneous Transmission Expenses were accepted as filed.

[215] Futral Direct Testimony at 18.

[216] Futral Direct Testimony at 19.

[217] Futral Direct Testimony at 20.

[218] Futral Direct Testimony at 20.

[219] Metts Rebuttal Testimony at 5.

[220] Amended Stipulation and Recommendation, Section 11.1.

Having considered the record and being otherwise sufficiently advised, the Commission finds that KU's forecasted increase to miscellaneous transmission power expenses is reasonable and supported by known and measurable changes to the pricing KU received in its operations. The Attorney General/KIUC's recommended adjustment is based on 16 months of inflation and not actual pricing increases. The Attorney General/KIUC's adjustment is rejected.

Depreciation and Amortization

Depreciation Rates. Along with its initial application for approval of a general adjustment of rates, KU also proposed a new, revised depreciation study for all assets associated with its operations to be accepted by the Commission.[221] KU stated that it included a depreciation study in this proceeding because the maintenance of sound depreciation rates requires periodic review of those rates and nearly five years had passed since a depreciation study was last performed for KU.[222] KU hired Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming) to perform a deprecation study.[223] This study was conducted to the electric plant as of June 30, 2024.[224] Gannett Fleming performed the depreciation study by using the straight-line remaining life method of depreciation, with the average service life procedure.[225] Gannett Fleming stated that the calculations were based on attained ages and estimated average

[221] Application at 15; Direct Testimony of John Spanos (Spanos Direct Testimony), Exhibit JJS-1.

[222] Application at 15.

[223] Spanos Direct Testimony at 2; LG&E's Response to Staff's First Request, Item 32, Attachment, Executive Summary.

[224] Spanos Direct Testimony, Exhibit JJS-KU-1, Executive Summary.

[225] Spanos Direct Testimony at 5.

service life and forecasted net salvage characteristics for each depreciable group of assets. KU's accounting policy has not changed since the last depreciation study was prepared.[226] However, Gannett Fleming noted that there have been changes in past and future retirement plans of assets and that these changes have caused the proposed remaining lives for many accounts to fluctuate from those proposed in the previous depreciation study as of June 30, 2020.[227] With regard to the depreciation study, the Attorney General/KIUC were the only intervenors who took issue with the depreciation rates and useful life spans proposed as a result of the depreciation study.[228] However, no intervenor provided testimony against the use of the straight-line remaining life method of depreciation, with the average service life procedure.

In the proposed Stipulation, the Signing parties agreed to remove terminal net salvage from KU's thermal generating units, correct calculation errors in KU's depreciation rates, and extend the estimated life spans for Mill Creek 5, Mill Creek 6, and Brown 12.[229]

Having considered the record and being otherwise sufficiently advised, the Commission finds that the Stipulation requires no modification and approves the proposed depreciation study, outside of the adjustments to remove terminal net salvage, correct calculation errors, and extend the estimated life spans for Mill Creek 5, Mill Creek

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[226] Spanos Direct Testimony, Exhibit JJS-KU-1, Executive Summary.

[227] Spanos Direct Testimony, Exhibit JJS-KU-1, Executive Summary.

[228] Kollen Corrected Direct Testimony at 3-4.

[229] Stipulation and Recommendation, Article 2.2(C); Stipulation and Recommendation, Article 2.2(I); Stipulation and Recommendation, Article 9.1.

6, and Brown 12 as further discussed below. Further, the Commission finds that outside of these adjustments, KU's depreciation study should be accepted as filed.

As a result of the aforementioned depreciation study, KU forecasted its Depreciation and Amortization Expense to be $421,404,049 in the forecasted test year in its initial application.[230] However, when KU amended its application through its August 25, 2025 Supplemental Filing, KU updated its depreciation and amortization expense to be $414,791,671 in the forecasted test year.[231] In its Base Period Update, filed October 15, 2025, KU's test-year level of Depreciation and Amortization expense remained unchanged from its amended application.[232] In response to discovery, KU stated that it included terminal net salvage in its depreciation rates, as well as interim net salvage and interim retirements.[233]

The Attorney General/KIUC originally recommended multiple adjustments to KU's proposed depreciation study, including removing terminal net salvage from all of KU's production plant accounts (thermal, wind, hydropower, and solar facilities),[234] removing estimated interim retirements and estimated interim net salvage from all of KU's future production plant accounts,[235] extending the life spans of KU's coal-fired generating units,[236] extending the life spans of KU's future production plant accounts (Mill Creek 5,

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230 Application, Tab 56, Schedule C-1 at 1.

231 KU's Supplemental Response to Staff's First Request, Item 54, Schedule C-1.

232 Base Period Update, Tab 56, Schedule C-1.

233 KU's Response to Attorney General/KIUC's First Request, Item 101(c); KU's Response to the Attorney General/KIUC's First Request, Item 101(e).

234 Corrected Direct Testimony of Lane Kollen (Kollen Corrected Direct Testimony) at 69.

235 Kollen Corrected Direct Testimony at 87.

236 Kollen Corrected Direct Testimony at 74.

Mill Creek 6, and Brown 12),[237] and recovering decommissioning expenses as a standalone expense, rather than as a component of the depreciation rates.[238] Further, during the period of time in which Stipulation negotiations transpired, KU and the Signing Parties discovered calculation errors in KU's depreciation rates that ultimately reduced KU's forecasted depreciation expense. Each individual adjustment is discussed in more detail below.

Depreciation Expense – Terminal Net Salvage. As mentioned above, KU included terminal net salvage in its application in the amount of $14,434,392 ($14,393,325 for thermal generating units, $41,066 for all other generating units).

Prior to the Stipulation, the Attorney General/KIUC originally recommended removing decommissioning costs from all production plant accounts, including thermal, wind, hydropower, and solar facilities, and, if these costs are approved within the revenue requirement, then the costs to decommission production plant accounts should be recovered as a standalone expense, rather than embedded in the depreciation rates.[239] The basis for the Attorney General/KIUC's recommendations centered around the statute, KRS 278.264(2), which states:

> (2) There shall be a rebuttable presumption against the retirement of a fossil fuel-fired electric generating unit. The commission shall not approve the retirement of an electric generating unit, authorize a surcharge for the decommissioning of the unit, or take any other action which authorizes or allows for the recovery of costs for the retirement of an electric generating unit, including any stranded asset recovery, unless the presumption created by this section is rebutted by evidence sufficient for the commission to find that:

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[237] Kollen Corrected Direct Testimony at 87.

[238] Kollen Corrected Direct Testimony at 78.

[239] Kollen Corrected Direct Testimony at 69; 78.

> (a) The utility will replace the retired electric generating unit with new electric generating capacity that:
>
> 1. Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area;
> 2. Maintains or improves the reliability and resilience of the electric transmission grid;
> 3. Maintains the minimum reserve capacity requirement established by the utility's reliability coordinator; and
> 4. Has the same or higher capacity value and net capability, unless the utility can demonstrate that such capacity value and net capability is not necessary to provide reliable service;
>
> (b) The retirement will not harm the utility's ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law;
>
> (c) The decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency; and
>
> (d) The utility shall not commence retirement or decommissioning of the electric generating unit until the replacement generating capacity meeting the requirements of paragraph (a) of this subsection is fully constructed, permitted, and in operation, unless the utility can demonstrate that it is necessary under the circumstances to commence retirement or decommissioning of the existing unit earlier.

The Attorney General/KIUC argued that the statute requires a utility to seek and obtain approval to retire a specific thermal generating unit with various thresholds that the utility must meet before the Commission may approve a requested retirement, and precludes recovery of decommissioning costs until after the Commission approves the retirement.[240] Further, the Attorney General/KIUC argued that decommissioning costs are estimates of costs many years into the future which are inherently not known or

[240] Kollen Corrected Direct Testimony at 65.

measurable, and the delayed recovery of decommissioning costs promotes intergenerational equity. The Attorney General/KIUC also argued that recovery of decommissioning costs prior to cash disbursements of such costs after the generating units actually are retired results in a decommissioning accumulated deferred tax asset (DTA), which is included in KU's rate base and capitalization, as the cost has to be financed.[241]

With respect to the adjustment to recover decommissioning costs as a standalone expense, the Attorney General/KIUC originally argued that including the decommissioning in the depreciation rates and expense overstates the decommissioning cost compared to a properly calculated standalone expense.[242] The Attorney General/KIUC further argued this point by stating this occurs because the decommissioning cost is included in the calculation of depreciation rates based on the gross plant at the depreciation study date. Those depreciation rates are then applied to the much greater gross plant in the test year compared to the plant at the study, which necessarily results in a proportionately greater and excessive decommissioning expense compared to the amount included in the depreciation study and depreciation rates.[243]

In rebuttal, KU stated that it is widely accepted that depreciation should include future net salvage, or decommissioning, costs, recovered on a straight-line basis, and that those costs should be based on the expected cost to retire KU's assets at the time

[241] Kollen Corrected Direct Testimony at 68–69.

[242] Kollen Corrected Direct Testimony at 76.

[243] Kollen Corrected Direct Testimony at 77.

of retirement or removal.[244] To further argue this point, KU cited to the National Association of Regulatory Utility Commissioners' (NARUC) Public Utility Depreciation Practices, which states that the goal of accounting for net salvage is to allocate the net cost of an asset to accounting periods, making due allowance for the net salvage, positive or negative, that will be obtained when the asset is retired.[245]

In regard to the Attorney General/KIUC's recommendation to recover decommissioning costs as a standalone expense, KU, in rebuttal, argued that the goal of depreciation is to allocate the costs of KU's assets over their service lives.[246] KU further argued that the Attorney General/KIUC's recommendation treats decommissioning costs as costs of transitioning to replacement generation facilities and they should be recovered as part of the replacement generating facility rather than as part of the generating facility to which they are actually associated and from rate payers who actually received service, or promotes intergenerational inequity.[247]

In the Stipulation, the Signing Parties agreed to reduce KU's revenue requirements to remove from depreciation expense terminal net salvage for thermal units including Mill Creek 2 and Brown 3.[248]

KRS 278.264(2) states that the Commission "shall not . . . take any other action which authorizes or allows for the recovery of costs for the retirement of an electric generating unit . . . unless the presumption created by this section is rebutted."

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[244] Rebuttal Testimony of John Spanos (Spanos Rebuttal Testimony) at 15.

[245] NARUC Public Utilities Depreciation Practices Manual at 18.

[246] Spanos Rebuttal Testimony at 20.

[247] Spanos Rebuttal Testimony at 20.

[248] Stipulation and Recommendation, Article 2.2(c).

Having considered the record and being otherwise sufficiently advised, the Commission finds that the Stipulation adjustment relating to the removal of terminal net salvage from KU's thermal generating units should be accepted. Since KRS 278.264(2) limits the Commission to remove terminal net salvage from thermal generating units only, the Commission finds that the Attorney General/KIUC's original adjustment to remove terminal net salvage from all production plant accounts is denied. Regarding recovering decommissioning costs as a standalone expense, the Commission finds that recovering decommissioning costs as a standalone expense would stray away from widely accepted depreciation principles.[249] KU's as-filed test year Depreciation Expense should be reduced to account for the removal of terminal net salvage from KU's fossil fuel-fired (thermal) generating units, consistent with the requirements of KRS 278.264(2). In the instant case, KU has the burden to overcome the presumption established in KRS 278.264 and KU has not done so here. Therefore, the Commission cannot allow recovery of costs for the retirement of electric generating units, except for those it has already received Commission approval to retire. Removing terminal net salvage from KU's thermal generating units reduces its test-year depreciation expense by $14,393,326 and reduces KU's base revenue requirement by $14,454,265. Further, the adjustment to remove terminal net salvage from KU's thermal generating units would increase KU's rate base, as a flow-through adjustment, by $5,401,095, which would increase the revenue

[249] The Commission notes that the Attorney General/KIUC's adjustment to recover decommissioning costs as a standalone expense, rather than embedded in depreciation rates, could create intergenerational inequity, creating a mismatch between the ratepayers who pay for the decommissioning costs associated with one of KU's generating units and the ratepayers who receive the benefit from that same asset.

requirement by $543,424.[250] The total revenue requirement reduction for this adjustment is $13,910,841.

Depreciation Expense – Calculation Error. As mentioned above, during the time in which Stipulation negotiations transpired, KU and the Signing Parties to the Stipulation found errors in the calculation of KU's depreciation rates, leading to a reduction to KU's as-updated test year revenue requirement.[251] The proposed adjustment would reduce KU's base revenue requirement by $3,974,532, offset by an increase from the addition to KU's rate base of $148,797, resulting in a net reduction to KU's base revenue requirement of $3,825,735.[252]

Having considered the record and being otherwise sufficiently advised, the Commission finds that the Stipulation adjustment related to correcting depreciation calculation errors is accepted. The Commission agrees with the Signing Parties that there was an error in the calculation in the depreciation rates that needed to be corrected, and finds that this adjustment should be accepted, as the adjustment is based on known and measurable changes to KU's depreciation rates. The resulting revenue requirement impact for KU will be a net reduction of $3,825,735.

Depreciation Expense – Life Spans for Production Plant Accounts. As mentioned above, KU proposed a revised depreciation study in this proceeding to be approved by

[250] The removal of terminal net salvage from KU's thermal generating units creates a flow-through reduction to KU's accumulated depreciation balance which, net of accumulated deferred income tax impacts, effectively increases KU's rate base and revenue requirement.

[251] Stipulation and Recommendation, Article 2.2(I).

[252] The reduction in KU's depreciation expense due to calculation errors found in the as-filed depreciation study creates a flow-through reduction to KU's accumulated depreciation balance which, net of accumulated deferred income tax impacts, effectively increases KU's rate base and revenue requirement.

the Commission, which included estimated life spans for each of KU's current and future generating units.[253] KU responded to multiple requests for information regarding its estimations for the useful lives of its generating units.[254]

Prior to the Stipulation, the Attorney General/KIUC recommended modifying the estimated life spans for KU's production plant accounts so they are consistent and rationalized for depreciation rate and expense purposes.[255] More specifically, the Attorney General/KIUC recommended extending the life spans for Ghent 2 by three years, Ghent 3 by four years, Ghent 4 by seven years, Brown Solar by five years, Simpsonville Solar Array 1 by five years, Simpsonville Solar Array 3 by five years, Simpsonville Solar Array 4 by five years, and all existing gas-fired combined cycle and combustion turbine generating units, with the exception of the Haefling units, by five years.[256] The Attorney General/KIUC further recommended that the estimated life span for KU's future generating assets (Mill Creek 5, Mill Creek 6, and Brown 12) be extended to 45 years, as opposed to the original proposal of 40 years.[257] The basis for the Attorney General/KIUC's recommendations centered around the idea that, under the proposed depreciation study, the life spans for similar generating units on the same site and built in the same general time frame differ, pointing out the individual Ghent and Mill Creek life

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[253] Application at 15.

[254] KU's Response to the Attorney General/KIUC's First Request, Item 93; KU's Response to the Attorney General/KIUC's First Request, Item 94; KU's Response to the Attorney General/KIUC's First Request, Item 95; KU's Response to the Attorney General/KIUC's First Request, Item 96; KU's Response to the Attorney General/KIUC's First Request, Item 97; KU's Response to the Attorney General/KIUC's First Request, Item 98; KU's Response to the Attorney General/KIUC's First Request, Item 99.

[255] Kollen Corrected Direct Testimony at 74.

[256] Kollen Corrected Direct Testimony at 74.

[257] Kollen Corrected Direct Testimony at 89.

spans as evidence.[258] The Attorney General/KIUC further argued that these generating units are extremely, and increasingly, valuable in the PJM capacity markets and in comparison to the costs of new replacement generation, so KU will continue to operate these generating units until they are uneconomic compared to the costs of new replacement generation.[259]

In its rebuttal testimony, KU argued that extending the life spans of any of KU's generating facilities not only creates economic and efficiency concerns, but would also create operational challenges at the locations with multiple units where many assets are common.[260] KU further stated that the Attorney General/KIUC's recommendation neglects certain instances that could shorten or extend the useful life of a generating unit, such as varying run cycles, inconsistent wear and tear, inefficiencies and operating costs unique to each of the units, and should instead be based only on the consistency that similar generating units constructed at the same site, during the same general time frame, should have the same life span.[261]

In the Stipulation, the Signing Parties agreed to extend the depreciation lives for Mill Creek 5, Mill Creek 6, and Brown 12 to 45 years, but did not extend the depreciation lives for KU's currently-in-service production plant accounts.[262]

Having considered the record and being otherwise sufficiently advised, the Commission finds that the Stipulation for the adjustments related to extending the life

[258] Kollen Corrected Direct Testimony at 70.

[259] Kollen Corrected Direct Testimony at 74.

[260] Spanos Rebuttal Testimony at 8.

[261] Spanos Rebuttal Testimony at 9.

[262] Stipulation and Recommendation, Article 9.1.

spans of KU's current and future generating units is accepted. The Commission finds that, for all of KU's current generating units, the estimated life spans are rooted in historical retirement data and life statistics that justify similar generating assets to have differing life spans. Therefore, the Commission finds that the Attorney General/KIUC's original recommendation to extend the life spans for KU's current generating units should be denied. However, with respect to the life spans for KU's future generating units, the Commission finds that, while these units are not in service yet, an estimated life span of 45 is reasonable and within the range of reasonable life spans for similar combined cycle and simple cycle combustion turbine generating units. The result of extending the life spans for Mill Creek 5, Mill Creek 6, and Brown 12 from 40 to 45 years has no effect on the revenue requirement in this proceeding.

Rate Case Expense. In its initial application, KU included an estimated $1,954,132 in its forecasted test year to account for its total rate case expenditures for legal, consulting, and newspaper advertising costs, amortized over approximately 2.79 years, with a corresponding Rate Case Amortization Expense of $700,946.[263] However, the Commission notes that, assuming a three year amortization period, using KU's estimated rate case expenditures in concurrence with the instant proceeding justifies a test year amortization expense of $651,377, not $700,946, which amounts to a reduction of $49,569. In responses to data requests throughout the case record, KU updated the amounts actually spent on its rate case monthly through January 26, 2026.[264] The

[263] Application, Tab 59, Schedule F-7 at 1.

[264] KU's Supplemental Response to Staff's First Request, Item 14(d) (filed Jan. 26, 2026); KU's Supplemental Response to Staff's First Request, Item 14(d) (filed Dec. 19, 2025); KU's Supplemental Response to Staff's First Request, Item 14(d) (filed Nov. 25, 2025); KU's Supplemental Response to Staff's

amortization of KU's rate case expenses went largely uncontested throughout the case record by all parties.

The amortization period of KU's actual rate case expenses was not included in the Stipulation, but it does fall within the "catch-all" provision in the Stipulation.

The Commission finds that the proposed Stipulation should be modified to account for KU's rate case expense amortization period of three years and to recognize KU's actual costs incurred in the development of the instant rate case. As stated previously, throughout the case record, KU provided monthly updates to its actual expenditures in concurrence with the instant rate case,[265] and, as of its most recent expense update, KU had expended a total of $1,703,695 resulting in a difference of $250,437. The Commission finds that a three-year amortization period for KU's rate case expense is reasonable due to the fact that under the terms of the Stipulation, the day that rates can go into effect in KU's next base rate proceeding would line up with a three year period. In the instant case, utilizing a three-year amortization period based on actual expenditures would result in a $83,479 reduction to KU's estimated rate case amortization expense. Further, the total adjustment reduces KU's rate case amortization expense by $133,048 and will reduce KU's base revenue requirement by $133,611.

First Request, Item 14(d) (filed Oct. 30, 2025); KU's Supplemental Response to Staff's First Request, Item 14(d) (filed Sept. 30, 2025).

[265] KU's Supplemental Response to Staff's First Request, Item 14(d); KU's Supplemental Response to Staff's First Request, Item 14(d); KU's Supplemental Response to Staff's First Request, Item 14(d); KU's Supplemental Response to Staff's First Request, Item 14(d) (filed Oct. 30, 2025); KU's Supplemental Response to Staff's First Request, Item 14(d).

Income Tax Expense. KU proposed a total income tax expense of $96,813,216 in its forecasted test year.[266] No intervenors took issue with KU's as-filed income tax expense in the forecasted test year throughout the case record. While the proposed Stipulation does not explicitly mention income tax as one of the adjustments to the revenue requirement, KU's as filed income tax expense in the forecasted test year was accepted as filed through the Stipulation's "catch all" provision. Having reviewed the record and being otherwise sufficiently advised, the Commission finds that the Stipulation needs modification to account for KU's test-year income tax expense. As discussed in more detail previously, the Commission adjusted KU's rate base and cost of capital, bringing KU's overall revenue requirement down from $2,094,432,447 in its original application[267] to the Commission-approved overall revenue requirement of $1,996,793,632. As a result of adjusting KU's rate base and cost of capital, the Commission finds that KU's income tax expense should be recalculated to reflect its approved rate base and cost of capital. In the instant matter, KU's total income tax expense in the forecasted test year will decrease resulting from the Commission's adjustments to KU's rate base and cost of capital. Reflective of KU's current state and federal tax rates, the Commission finds that KU's total income tax expense will be $80,589,866 in the forecasted test year.

CAPITAL PROJECTS

KU has numerous capital projects planned in the coming years. As many of the projects were discussed in tandem with LG&E, unless otherwise noted, this discussion

[266] August 25, 2025 Supplemental Filing, Item 54, Schedule C-1.

[267] August 25, 2025 Supplemental Filing, Item 54, Schedule A.

will include both LG&E and KU's projects. In terms of distribution projects, LG&E/KU have recently developed a comprehensive plan to continue reliability and resiliency improvements in a manner that is cost-effective and will harden the distribution system and improve overall reliability including major-event day reliability called Distribution System Hardening and Resiliency Plan (DSHARP).[268] DSHARP is a portfolio of investments in system hardening and resiliency designed to improve distribution reliability, including Major Event Days (MEDs), by 39 percent over a ten-year rolling average.[269]

The investments included in the DSHARP portfolio include: (1) Installing additional remotely operable distribution reclosers, expanding the Distribution Automation (DA) program to enable more targeted fault sectionalization and expand self-heal capability to more feeders; (2) building distribution circuit ties to enable self-heal capability on circuits that don't already have tie capability; (3) targeted hardening of existing overhead distribution lines, including the use of spacer cable in high-risk areas; and (4) targeted undergrounding of existing overhead distribution lines in high-risk, difficult to restore areas.[270] LG&E/KU estimated the total cost of those investments at $445 million, of which approximately $121 million is planned to be spent through the forecasted test year.[271] LG&E/KU stated that the corresponding economic cost savings, would total approximately $312 million annually (39 percent savings from $800 million in economic

[268] Waldrab Direct Testimony at 12.

[269] Waldrab Direct Testimony at 12.

[270] Waldrab Direct Testimony at 12-13.

[271] Waldrab Direct Testimony at 16.

impact) assuming a 96 minute reduction in “all-in” System Average Interruption Duration Index (SAIDI).[272]

LG&E/KU will also continue their inspection, maintenance and replacement of aging infrastructure, construct new distribution infrastructure to meet customer demand, and maintain ongoing operations.[273] LG&E/KU have planned for approximately $24 million in investment over the next five years to address 28 miles of distribution lines in the “relatively high risk” areas.[274] For the period from January 1, 2022, to June 30, 2026, KU and LG&E combined have spent or plan to spend $1.5 billion in capital in their distribution system, broken down by company in the following categories:[275]

Category	LG&E	KU	Total (M)
Connect New Customers	$ 193	$ 373	$ 566
Enhance the Network	139	207	346
Maintain the Network	187	173	360
Repair the Network	105	120	225
Miscellaneous	6	10	16
Total	$ 630	$ 883	$ 1,513

For transmission related projects, from January 1, 2022, to June 30, 2026, LG&E/KU have spent and plan to spend $1,024 million in capital on transmission-related projects.[276] Below is a table that summarizes these investments:[277]

[272] Waldrab Direct Testimony at 16.

[273] Waldrab Direct Testimony at 16.

[274] Waldrab Direct Testimony at 28.

[275] Waldrab Direct Testimony at 17.

[276] McFarland Direct Testimony at 25.

[277] McFarland Direct Testimony at 26.

Transmission	LG&E $ M	KU $ M	Total ($ M) (Jan. 1, 2022 – June 30, 2026)
Proactive Replacement	$ 97	$ 543	$ 640
Connect New Customers	34	136	170
Transmission Expansion Plan	36	64	100
Generation Expansion Plan	5	18	23
Reliability	3	24	27
Other	10	54	64
Total	$ 185	$ 839	$ 1,024

LG&E/KU have created a risk adjusted portfolio of transmission system investments called the Transmission System Hardening and Resiliency Plan (TSHARP).[278] The asset replacements included in this plan include (1) circuit rebuilds; (2) transformer replacements; (3) circuit breaker replacements; and (4) relay panel replacements.[279] The resiliency programs included in TSHARP are: (1) hardening of radial taps; and (2) continued expansion of automatic remote sectionalizing through installation of motor-operated switching.[280]

For information technology (IT) infrastructure, LG&E/KU's current IT infrastructure consists of an array of interconnected platforms that fall into a handful of categories: Field operations, cybersecurity, business-side IT (often referred to as enterprise resource planning, or "ERP"), customer side IT, and content management platforms.[281] LG&E/KU have developed a five-year plan to overhaul their aging IT infrastructure and reorient their

[278] McFarland Direct Testimony at 9.

[279] McFarland Direct Testimony at 10.

[280] McFarland Direct Testimony at 10.

[281] Johnson Direct Testimony at 3.

IT expenditures toward improving their IT operations.[282] In 2024, PPL launched a target and strategic plan to consolidate its systems, overhaul its processes, and become more flexible to future changes in IT.[283] LG&E/KU described PPL's plan to upgrade IT systems as follows:

> PPL organized its plan around a number of different "value streams" – which are simply categories of solutions and people who build those solutions for a broader business objective. The value streams included in the plan are: (1) Advanced Customer Operations and Engagement, which includes Customer Information System (CIS) and customer experience platforms and metering modernization; (2) Predictive Field Operations and Asset Management, which includes Work and Asset Management Consolidation; (3) Grid and Pipeline of the Future, which includes unified Geographic Information System (GIS) and intelligent grid operations across all utilities; (4) Next Generation or "NextGen" Enterprise Services, which includes human resources solutions and corporate and financial enterprise solutions; (5) Data analytics and Artificial Intelligence (AI); (6) Cybersecurity; and (7) Infrastructure and Other.
>
> Across all value streams, PPL's plan further includes three overlapping phases: Run, Grow, and Transform. The "Run" phase of plan is focused on stabilizing and securing PPL's day-to-day operations by replacing obsolete hardware and software systems. During this phase, PPL will also free up its IT resources for more proactive projects by contracting these more basic IT support operations to a managed services company. The "Grow" phase will focus on preparing PPL's different utilities and employees to implement a more cohesive and efficient IT infrastructure. Finally, the "Transform" phase of the plan will focus on bringing the PPL's IT systems and capabilities into the future.

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[282] Johnson Direct Testimony at 10.

[283] Jonhson Direct Testimony at 11-12.

The total amount of capital costs for these value streams is summarized below for KU only:[284]

Capital Project	Capital Cost (Forecasted Test Period)	Capital Costs Total Over 5-Year Planning Horizon
Advanced Customer Operations and Engagement	$39 million	$78 million
NextGen Enterprise Services	$24.3 million	$27.2 million
Grid and Pipeline of the Future	$17.5 million	$22.8 million
Field Operations and Asset Management	$10.9 million	$10.9 million
Cybersecurity	$5.3 Million	$7.8 million
Total	$ 97 Million	$146.7 Million

LG&E/KU also stated they have spent or are planning to spend over $700 million in non-mechanism generation capital to ensure LG&E/KU's coal and gas generation fleet remains well maintained, in good repair, and reliable.[285] LG&E/KU stated that they have spent or plan to spend approximately $350 million in advanced metering infrastructure.[286]

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[284] McFarland Direct Testimony at 16-29.

[285] Application at 9-10.

[286] Application at 10.

LG&E/KU also plans to spend approximately $336 million in smart grid investments from 2025 to 2029.[287]

CAPITALIZATION

Capitalization. In its application, KU proposed an adjusted total capitalization for the forecasted period of $6,186,741,227 to be used as the return on component of its revenue requirement.[288] KU provided updated adjusted total capitalization for the forecasted period of $6,186,150,159 or a reduction of $591,068.[289] For the reasons discussed below, the Commission finds that KU's utilization of the capitalization methodology is rejected.

KU's Proposed Capitalization Adjustments. KU proposed 12 adjustments to get to an updated adjusted total capitalization for the forecasted period of $6,186,150,159 that represented changes to KU's capitalization for the 12 months ending December 31, 2026.[290] These adjustments were uncontested by the intervenors. Described below are the updated adjustments that LG&E filed in its August 25, 2025 Supplemental Filing. As these adjustments are related specifically to KU's capitalization methodology, these adjustments are only relevant for comparative purposes, and no findings are necessary.

Electric Energy Inc. Deferred Tax. In its application KU proposed an adjustment to remove $323,302 from capitalization.[291] In its August 25, 2025 Supplemental Filing,

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[287] Application at 15.

[288] Application, Schedule A.

[289] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J, SCH J-1.1|J-1.2.

[290] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J, Sch J-1.1|J-1.2.

[291] Application, Tab 63, Schedule J-1.1/J-1.2.

this adjustment was unchanged.[292] This adjustment was associated with the tax treatment of Electric Energy Inc. equity investments because it is a non-utility investment.[293]

Investment in Ohio Valley Electric Corporation (OVEC). In its application KU proposed an adjustment to remove $250,000 from capitalization.[294] In its August 25, 2025 Supplemental Filing, this adjustment was unchanged.[295] This adjustment was associated with the equity investment in the OVEC equity investments because it is a non-utility investment.[296]

Net Non-Utility Property. In its application KU proposed an adjustment to remove $37,881from capitalization.[297] In its August 25, 2025 Supplemental Filing, this adjustment was unchanged.[298] This adjustment was related to non-utility property investment to ensure that the rate base reflects only those assets dedicated to providing electric service to the public.[299]

ADIT Proration. In its application KU proposed an adjustment to remove $488,119 from capitalization. [300] In its August 25, 2025 Supplemental Filing, this adjustment was

[292] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J, SCH J-1.1|J-1.2.

[293] Fackler Direct Testimony at 27.

[294] Application, Tab 63, Schedule J-1.1/J-1.2.

[295] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J, SCH J-1.1|J-1.2.

[296] Fackler Direct Testimony, at 27.

[297] Application, Tab 63, Schedule J-1.1/J-1.2.

[298] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J, SCH J-1.1|J-1.2.

[299] Fackler Direct Testimony at 27.

[300] Application, Tab 63, Schedule J-1.1/J-1.2.

updated to $426,922.[301] This adjustment was to change the ADIT amounts from the 2025 Business Plan to reflect 13-month average to the pro rata method in accordance with §1.167(l)-1(h)(6)(ii) of the Internal Revenue Code (IRC).[302]

<u>AMI Savings Regulatory Liability</u>. In its application KU proposed an adjustment to increase capitalization by $1,064,275.[303] In its August 25, 2025 Supplemental Filing, this adjustment was unchanged.[304] This adjustment was to reflect the change in the AMI Savings Regulatory Liability amortization from a 15-year amortization to a five-year amortization.[305]

<u>WACC Regulatory Asset New Generation</u>. In its application KU proposed an adjustment to remove $5,910,541 from capitalization. [306] In its August 25, 2025 Supplemental Filing, this adjustment was updated to $6,088,533.[307] This adjustment was associated with the WACC regulatory asset for new generation projects accruing AFUDC. The underlying assets are being excluded from capitalization because they are not yet in service, the corresponding regulatory asset representing the return on those investments is also removed to ensure the 2026 revenue requirement is not artificially inflated by future generation costs.[308].

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[301] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J, SCH J-1.1|J-1.2.

[302] Fackler Direct Testimony at 72.

[303] Application, Tab 63, Schedule J-1.1/J-1.2.

[304] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J, SCH J-1.1|J-1.2.

[305] Fackler Direct Testimony at 23.

[306] Application, Tab 63, Schedule J-1.1/J-1.2.

[307] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J, SCH J-1.1|J-1.2.

[308] Fackler Direct Testimony at 70.

IT Regulatory Asset. In its application KU proposed an adjustment to increase capitalization by $1,703,956.[309] In its August 25, 2025 Supplemental Filing, this adjustment was updated to $1,748,073.[310] This adjustment was proposed to reflect the inclusion of the increase in IT software implementation costs regulatory asset amortization due to higher costs expected to be incurred.[311]

ECR. In its application KU proposed an adjustment to reduce capitalization by $654,219,543.[312] In its August 25, 2025 Supplemental Filing, this adjustment was updated to $654,219,022.[313] This adjustment was for the removal of the amounts associated with the ECR mechanism since ECR investments have their own dedicated full-cost-recovery tracker.[314]

DSM. In its application KU proposed an adjustment to KU proposed to reduce capitalization by $148,787.[315] In its August 25, 2025 Supplemental Filing, this adjustment was unchanged.[316] This adjustment was for the removal of the amounts associated with the DSM mechanism since DSM investments have their own dedicated full-cost-recovery tracker.[317]

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[309] Application, Tab 63, Schedule J-1.1/J-1.2.

[310] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J, SCH J-1.1|J-1.2.

[311] Fackler Direct Testimony at 29.

[312] Application, Tab 63, Schedule J-1.1/J-1.2.

[313] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J, SCH J-1.1|J-1.2.

[314] Fackler Direct Testimony at 28.

[315] Application, Tab 63, Schedule J-1.1/J-1.2.

[316] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J, SCH J-1.1|J-1.2.

[317] Fackler Direct Testimony at 28.

AMI. In its application KU proposed an adjustment to increase the AMI project capitalization amount by 30,379.[318] In its August 25, 2025 Supplemental Filing, this adjustment was unchanged.[319] This adjustment was to align the AMI project deployment schedule with the 2026 financial projections.

CPCN New Generation. In its application KU proposed an adjustment to remove $640,562,573 from capitalization.[320] In its August 25, 2025 Supplemental Filing, this adjustment was updated to $687,263,973.[321] This adjustment was associated with the capital costs of new generation projects accruing AFUDC approved that are not yet in service.[322]

Trimble County Stack Project. In its application KU proposed an adjustment to remove $18,890,884 from capitalization.[323] In its August 25, 2025 Supplemental Filing, this adjustment was updated to $18,890,748.[324] This adjustment was to reflect the KUs' updated plan to replace the liners rather than build a new stack.[325]

Rate Base. In its application, KU calculated its rate base for the forecasted period to be used to allocate KU's total capitalization between the retail and wholesale

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[318] Application, Tab 63, Schedule J-1.1/J-1.2.

[319] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J, SCH J-1.1|J-1.2.

[320] Application, Tab 63, Schedule J-1.1/J-1.2.

[321] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J, SCH J-1.1|J-1.2.

[322] Fackler Direct Testimony at 27.

[323] Application, Tab 63, Schedule J-1.1/J-1.2.

[324] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J, SCH J-1.1|J-1.2.

[325] Fackler Direct Testimony at 72.

jurisdictions which was $6,094,469,285.[326] KU also provided an updated rate base for the forecasted period of $6,096,079,612 which is an increase from the application of $1,610,327.[327] For the reasons discussed below, the Commission finds that KU should utilize the rate base methodology.

KU's Proposed Rate Base Adjustments. KU proposed six adjustments to get to an updated adjusted total rate base for the forecasted period of $6,096,079,612 that represented changes to KU's rate for the 12 months ending December 31, 2026.[328] These adjustments were uncontested by the intervenors. Described below are the adjustments that KU filed in its application and in its August 25, 2025 Supplemental Filing.

ECR. In its application KU proposed an adjustment to reduce rate base by $654,219,543.[329] In its August 25, 2025 Supplemental Filing, this adjustment was updated to $654,219,022.[330] This adjustment was associated with the removal of the ECR mechanism since ECR investments have their own dedicated full-cost-recovery tracker.[331] The Commission finds that this adjustment is reasonable and should be accepted, as these amounts are recovered through the ECR mechanism and to ensure there is not double recovery for these amounts.

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[326] Application, Tab 55, Schedule B.

[327] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule B-1.

[328] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule Support B-1.1F.

[329] Application, Tab 63, Supporting Schedule B-1.1.

[330] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule Support B-1.1F.

[331] Fackler Direct Testimony at 12.

DSM. In its application KU proposed an adjustment to reduce rate base by $148,787.[332] In its August 25, 2025 Supplemental Filing, this adjustment was unchanged.[333] This adjustment was for the removal of the amount associated with the DSM mechanism since DSM investments have their own dedicated full-cost-recovery tracker.[334] The Commission finds that this adjustment is reasonable and should be accepted, as these amounts are recovered through the DSM mechanism and to ensure there is not double recovery for these amounts.

Asset Retirement Obligation (ARO). In its application KU proposed an adjustment to reduce rate base by $21,397,324.[335] In its August 25, 2025 Supplemental Filing, this adjustment was unchanged.[336] This adjustment was to reflect the removal of ARO assets from its rate base in future rate cases consistent with Case Nos. 2003-00426 and 2003-00427,[337] where the Commission approved a stipulation that requested the Commission's approval for the following:

> 1) Approving the regulatory assets and liabilities associated with adopting SFAS No. 143 and going forward;
>
> 2) Eliminating the impact on net operating income in the 2003 ESM annual filing caused by adopting SFAS No. 143;

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[332] Application, Tab 63, Supporting Schedule B-1.1.

[333] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule Support B-1.1F.

[334] Fackler Direct Testimony at 12.

[335] Application, Tab 63, Supporting Schedule B-1.1.

[336] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule Support B-1.1F.

[337] Case No. 2003-00426, *Application of Louisville Gas and Electric Company For An Order Approving An Accounting Adjustment to be Included in Earnings Sharing Mechanism Calculations for 2003* (Ky. PSC Dec. 23, 2003), Order at 3; Case No. 2003-00427, *Application of Kentucky Utilities Company For An Order Approving An Accounting Adjustment to be Included in Earnings Sharing Mechanism Calculations for 2003* (Ky. PSC Dec. 23, 2003), Order at 3.

3) To the extent accumulated depreciation related to the cost of removal is recorded in regulatory assets or regulatory liabilities, reclassifying such amounts to accumulated depreciation for rate-making purposes of calculating rate base; and

4) Excluding from rate base the ARO assets, related ARO asset accumulated depreciation, ARO liabilities, and remaining regulatory assets associated with the adoption of SFAS No. 143.

The Commission finds this adjustment is reasonable and is accepted, as it keeps with the ARO asset treatment for rate base that was approved in 2003.

New Generation. In its application KU proposed an adjustment to remove $640,562,573 from rate base.[338] In its August 25, 2025 Supplemental Filing, this adjustment was updated to $687,263,973.[339] This adjustment was associated with the capital costs of new generation projects accruing AFUDC that are not yet in service.[340] The Commission finds that the proposed adjustment is reasonable and should be accepted as the adjustment was made to remove projects not in service during the test period and more accurately affects projects in-service during the test period.

Trimble County Stack Project. In its application KU proposed an adjustment to remove $18,890,884 from rate base.[341] In its August 25, 2025 Supplemental Filing, this adjustment was updated to $18,890,748.[342] This adjustment was to reflect the KU's

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338 Application, Tab 63, Supporting Schedule B-1.1.

339 Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule Support B-1.1F.

340 Fackler Direct Testimony at 70.

341 Application, Tab 63, Supporting Schedule B-1.1.

342 Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule Support B-1.1F.

updated plan to replace the liners rather than build a new stack.[343] KU explained there was deterioration of the stack liner on Trimble County 1, and that repairs were not feasible.[344] KU explained that its options were to either to consider a full liner replacement or construction of a completely new chimney with new liners.[345] KU stated that it can install a new liner for each unit for a combined total of approximately $100 million without affecting the safety or reliability of those facilities, versus $216 million to design and construct a new chimney.[346] The Commission finds that the proposed adjustment is reasonable and should be accepted as the adjustment reflects KU's updated construction plans for Trimble County 1 and 2.

AMI. In its application KU proposed an adjustment to increase the AMI project base rate amount by $30,379.[347] In its August 25, 2025 Supplemental Filing, this adjustment was unchanged.[348] This adjustment was for forecasted increases in CWIP and AFUDC associated with the AMI deployment project.[349] The Commission finds that the proposed adjustment is reasonable and should be accepted because KU's forecasted increases in CWIP and AFUDC are reasonable.

Capitalization vs. Rate Base. In its application, KU proposed an adjusted total capitalization for the forecasted period of $6,186,741,227 to be used as the return on

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[343] Fackler Direct Testimony at 72.

[344] Bellar Direct Testimony at 12.

[345] Bellar Direct Testimony at 12.

[346] Bellar Direct Testimony at 12.

[347] Application, Tab 63, Supporting Schedule B-1.1.

[348] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule Support B-1.1F.

[349] Fackler Direct Testimony at 72.

component of its revenue requirement.[350] KU also calculated its rate base for the forecasted period to be used to allocate KU's total capitalization between the retail and wholesale jurisdictions which was $6,094,469,285.[351] The difference between KU's capitalization amount and rate base amount in its application is $92,271,942. KU explained that the difference between the capitalization and rate base methodology is primarily related to the fact that capitalization includes the funding for working capital under the balance sheet approach, which includes regulatory assets and liabilities and other deferred debits.[352] KU provided updated adjusted total capitalization for the forecasted period of $6,186,150,159 or a reduction of $591,068.[353] KU also provided an updated rate base for the forecasted period of $6,096,079,612, which is an increase from the application of $1,610,327.[354] The difference between KU's capitalization and rate base in its base period update was $90,070,547.

Prior to the Stipulation, the Attorney General/KIUC pointed to several utilities' use of rate base methodology in their most recent rate cases as a starting point for the argument against using capitalization methodology.[355] The Attorney General/KIUC stated:

> The use of rate base is more precise and accurate than capitalization to calculate the return on component of the base revenue requirement. It allows the Commission to specifically review, assess, and quantify each of the costs that

[350] Application, Tab 54, Schedule A.

[351] Application, Tab 55, Schedule B.

[352] KU's Response to Staff's Second Request, Item 49.

[353] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule A.

[354] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule Support B-1.1F.

[355] Kollen Corrected Direct Testimony at 11-17.

> will earn a return on, including those costs that are subtracted from rate base, such as net liability accumulated deferred income taxes (ADIT) and negative cash working capital (CWC), the normal result when CWC is properly calculated using the lead/lag approach and correctly excludes non-cash expenses.[356]

In rebuttal testimony, KU stated that the capitalization methodology is more straightforward, eliminates the need for theoretical adjustments, is the most complete valuation, and if rate base is adjusted appropriately, there should be no material difference between the rate base and capitalization calculations.[357] KU cited to prior cases where the Commission has agreed to the capitalization methodology, and that KU has been using this methodology for 40 years.[358] KU argued that it is different from the other investor-owned utilities that use the rate base methodology because, "…the primary if not exclusive regulatory jurisdiction for the KU is Kentucky," while the other investor owned utilities mostly operate outside of the state.[359] KU provided several reasons why capitalization is a better measure of value of property than rate base: (1) capitalization is simpler and more transparent; (2) rate base improperly excludes certain assets and liabilities; (3) there is a mismatch for accumulated deferred income taxes (ADIT) in rate base, which does not exist in capitalization; (4) KU's non-regulated activities are de minimis; and (6) KU's reconciliation between rate base and capitalization validates its lead lag study.[360] KU finally asked that, if the Commission should choose to use rate

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[356] Kollen Corrected Direct Testimony at 14.

[357] Garrett Rebuttal Testimony at 2.

[358] Garrett Rebuttal Testimony at 2-3.

[359] Garrett Rebuttal Testimony at 3.

[360] Garrett Rebuttal Testimony at 4.

base, that it include all regulatory assets and regulatory liabilities established in connection with providing utility service in rate base to appropriately compensate both LG&E/KU and customers for the deferrals.[361]

In the Stipulation, the Signing Parties agreed to use “the Companies' capitalizations” as the return on component for the calculation of the revenue requirement and, “[i]n their next base rate cases, the Companies will present their rate base calculations with regulatory assets and liabilities included”.[362] KU's updated adjusted total capital for the forecasted period is $90,070,547 higher than its updated rate base. KU's capitalization, being higher than its rate base, means that KU has financed non-rate base items and is including them in the return on component of the revenue requirement. KU is not entitled to a return on financing that is not associated with rate base items. A difference of $90,070,547 between the methodologies is not *de minimis*. Therefore, the Commission finds the rate base methodology will be used for the calculation of KU's revenue requirement. This modification results in a $9,062,329 reduction to the revenue requirement. KU's proposed regulatory asset treatment is discussed further below.

Attorney General/KIUC's Proposed Rate Base Adjustments. The Attorney General/KIUC's originally proposed several adjustments to KU's application rate base calculations that are discussed below.

Remove Generation and Transmission Construction Work in Progress (CWIP) from Rate Base. In its application, KU proposed to include $246,888,211 of Generation and

[361] Garrett Rebuttal Testimony at 9.

[362] KU/LG&E Stipulation Testimony at 13 and 24.

Transmission in its adjusted forecasted Construction Work in Progress (CWIP).[363] KU provided an updated $248,853,046 of Generation and Transmission in its adjusted forecasted CWIP in its Base Period Update.[364]

Prior to the Stipulation, the Attorney General/KIUC argued that KU's Transmission CWIP should be removed from rate base and capitalized as Allowance for Funds Used During Construction (AFUDC).[365] The Attorney General/KIUC stated that KU is seeking the recovery of construction financing costs before the construction is completed and placed into service instead of capitalizing the cost as AFUDC then recovering those costs over the service lives.[366] The Attorney General/KIUC pointed to several previous CPCN cases where KU proposed the use of AFUDC and was authorized by the Commission [367] The Attorney General/KIUC then argued that the use of AFUDC on an ad hoc basis leads to a hybrid form of rate making that is not necessary and is not consistent with other investor owned utilities under the Commissions regulation.[368]

The Attorney General/KIUC stated that the asset ADIT created under the CWIP approach is greater than under the AFUDC approach and harms customers through increased costs during the construction period and service life of the asset.[369] The Attorney General/KIUC compared KU's requested WACC of 7.92 percent to consumer

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[363] Application, Tab 55, Schedule B-4.

[364] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule B-4.

[365] Kollen Corrected Direct Testimony at 17.

[366] Kollen Corrected Direct Testimony at 18.

[367] Kollen Corrected Direct Testimony at 18-19.

[368] Kollen Corrected Direct Testimony at 18-19.

[369] Kollen Corrected Direct Testimony at 22.

credit card debt cost of approximately 30 percent and states that customers are "essentially" financing on behalf of the utility at their higher marginal cost of capital under the CWIP approach.[370] The Attorney General/KIUC/s recommendation to exclude all generation and transmission CWIP from rate base was a reduction in the KU revenue requirement of $25,038,000.[371]

In rebuttal testimony, KU pointed to "nearly" identical testimony in KU's last two base rate cases and KU was not required to move from CWIP.[372] KU stated that CWIP has many benefits compared to AFUDC including lower capitalized costs, stable cash flows, and improved quality of cash earnings.[373] KU stated that, because the Commission never directed KU to change its CWIP methodology KU's rate base is much lower than it would otherwise be and their embedded cost of debt is relatively low.[374] KU argued that the use AFUDC for these projects is logical, easily quantifiable, and does not create a ratemaking issue.[375] KU mentioned KU's AFUDC policy states projects less than $100,000 or projects that do not have construction periods comprising three consecutive months do not qualify for AFUDC treatment, and thus, KU argued Kollen's recommendation to include all projects under AFUDC ignores KU's policy.[376] KU argued that the Attorney General/KIUC's exclusion does not prevent the hybrid approach of

[370] Kollen Corrected Direct Testimony at 22.

[371] Kollen Corrected Direct Testimony at 23

[372] Garrett Rebuttal Testimony at 21-22.

[373] Garrett Rebuttal Testimony at 22.

[374] Garrett Rebuttal Testimony at 24.

[375] Garrett Rebuttal Testimony at 25.

[376] Garrett Rebuttal Testimony at 25.

AFUDC and CWIP they claimed as not rational and would only complicate ratemaking even further and deny KU the ability to recover financing costs.[377] KU cited to two studies that show many states have electric utilities with precedent for CWIP in rate base.[378] KU stated that the switch to AFUDC would result in the denial of over four years of AFUDC accruals since KU's last base rate case and require a large administrative burden to transition decades of CWIP accounting to AFUDC.[379]

This specific adjustment was not mentioned in the Stipulation agreement, but due to the catch-all provision, KU's original CWIP and AFUDC methodologies from the application are unchanged.[380]

Having considered the record and being otherwise sufficiently advised, the Commission finds that KU's continued accrual of CWIP and AFUDC for certain projects is reasonable. The Commission finds that no adjustment to remove Generation and Transmission CWIP from rate base is necessary given KU's historic use of CWIP for normal operations plant additions and record keeping to properly remove AFUDC.

<u>Exclude Non-Cash Items from Rate Base</u>. In its application KU provided a Lead/Lag study for the forecasted test period which produced a Cash Working Capital (CWC) (Lead/Lag) of $39,263,195.[381] In its base period update, KU provided a Lead/Lag study

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[377] Garrett Rebuttal Testimony at 25

[378] Garrett Rebuttal Testimony at 25.

[379] Garrett Rebuttal Testimony at 27-28.

[380] Amended Stipulation, Section 11.1.

[381] Application, Tab 55, Schedule B-5.2F.

for the forecasted test period which produced an updated CWC (Lead/Lag) of $38,306,064.[382]

Prior to the Stipulation, the Attorney General/KIUC argued that KU's CWC was overstated.[383] The Attorney General/KIUC argued KU included non-cash items in its calculation of CWC.[384] The Attorney General/KIUC stated that Commission Orders and/or utility filings in other investor owned utility base rate case proceedings, where CWC is calculated using a lead/lag study, exclude non-cash expense.[385] The Attorney General/KIUC pointed to where KU's testimony acknowledged the Commission precedent but included the non-cash expenses anyway.[386] The Attorney General/KIUC argued that the use of zero expense days is incorrect and assumes that depreciation, amortization, and deferred income tax expenses actually are paid in cash and paid in cash instantaneously at the beginning of the month in which the expenses are recorded.[387] The Attorney General/KIUC then stated that these assumptions are wrong because KU never disburses cash for these expenses instantaneously.[388] The Attorney General/KIUC also stated that KU only disperses cash one time for income tax and never

[382] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule B-5.2.1F.

[383] Kollen Corrected Direct Testimony at 24.

[384] Kollen Corrected Direct Testimony at 24.

[385] Kollen Corrected Direct Testimony at 24.

[386] Kollen Corrected Direct Testimony at 25-26.

[387] Kollen Corrected Direct Testimony at 26.

[388] Kollen Corrected Direct Testimony at 33.

for deferred income tax.[389] The Attorney General/KIUC recommended removing non-cash expenses from the CWC (lead/lag).[390]

In rebuttal testimony, KU argued that it needs to retain the additional working capital associated with depreciation, amortization, and deferred income tax expenses because including additional working capital in rate base ensures adequate compensation to shareholders, when failing to do so could result in increased financing costs.[391] Second, KU argued that, when a capital asset depreciates or amortizes, value is consumed in providing service to customers, a real expense occurs and the lag for receiving funds for that expense must be accounted for.[392] KU stated that using zero expense lead days for these non-cash items is entirely appropriate, and compared that expense to any other expense KU incurs and the associated revenue lag.[393] KU argued that when an entity defers income taxes, it acquires an obligation that will come due and because it is not paid in that instance does not make it any less of an expense for which the entity must receive cash in compensation.[394] KU referred to KU's response to the Attorney General/KIUC's First Data Request where KU stated:

> Cash was outlaid at different points in time (e.g., when a capital asset was being constructed, when storm restoration from a major storm was incurred and costs were paid, etc.). Therefore, the Company does not need to recognize a cash

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[389] Kollen Corrected Direct Testimony at 33.

[390] Kollen Corrected Direct Testimony at 34.

[391] Rebuttal Testimony of Andrea Fackler (Fackler Rebuttal Testimony) (Sept. 30, 2025) at 2-3.

[392] Fackler Rebuttal Testimony at 2-3.

[393] Fackler Rebuttal Testimony at 4.

[394] Fackler Rebuttal Testimony at 4.

> outlay for these items but does need to recognize the lag in when the expense will be collected from customers.[395]

This specific adjustment was not mentioned in the Stipulation agreement, but due to the catch all provision, KU's original application CWC (lead/lag) calculation methodology including non-cash items was accepted unchanged.[396]

Having considered the record and being otherwise sufficiently advised, the Commission finds that KU's CWC (lead/lag) should be modified to remove non-cash items and as such, rejects the Stipulation on this point. The Commission has previously disallowed the inclusion of depreciation, amortization, and deferred income tax expenses in utility lead/lag studies and believes an expense lead day of zero is not reasonable for rate making.[397] KU does not disperse cash for depreciation, amortization, and deferred income tax expenses. Removing non-cash items from KU's updated CWC (lead/lag) results in a reduction to the revenue requirement of $4,054,021.

Exclude Non-Cash Coal Items from Rate Base. In its application, KU included a forecast period amount of $395,821,642 of Fuel-Coal Expense at 45.01 revenue lag days and (36.77) expense lag days for an addition to working capital requirement of $8,453,888.[398]

Prior to the Stipulation, the Attorney General/KIUC argued that, Fuel-Coal Expense is a non-cash expense and should be excluded from the working capital requirement for

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[395] Fackler Rebuttal Testimony at 5.

[396] Amended Stipulation, Section 11.1.

[397] Case No. 2024-00276, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief* (Ky. PSC Aug. 1, 2025), final Order at 17-19; Case No. 2025-00122, *Electronic Application of Kentucky-American Water Company for an Adjustment of Rates* (Ky. PSC Dec. 16, 2025), final Order at 45-47.

[398] Application, Tab 55, Schedule B-5.2.

KU.[399] The Attorney General/KIUC explained that Fuel-Coal Expense is an allocation of the balance sheet Fuel-Coal inventory amounts recorded to expense for accounting purposes as the Fuel-Coal inventories are consumed and that cash disbursement only occurs when coal inventories are purchased from the vendor.[400] The Attorney General/KIUC then stated that the fuel inventories are already included as a separate component of rate base, and there is not a second disbursement of cash.[401] The Attorney General/KIUC then stated KU assumed 36.77 expense lag days for Fuel-Coal Expense, but there can be no expense lag days for non-cash expenses.[402] The Attorney General/KIUC recommended excluding non-cash Fuel-Coal Expense from the CWC (lead/lag).[403]

In rebuttal testimony, KU argued that the Attorney General/KIUC is incorrect to remove the Fuel-Coal Expense from the CWC (lead/lag) for the same reasons KU listed in the argument against removing other non-cash items from the CWC (lead/lag).[404] KU stated it needs to burn coal in order to generate electricity and the intermediate steps of recording coal to, and removing coal from, inventory on the KU's balance sheet does not negate the need for, or make it inappropriate to, address the lead-lag associated with fuel-coal expense.[405]

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[399] Kollen Corrected Direct Testimony at 35.

[400] Kollen Corrected Direct Testimony at 35.

[401] Kollen Corrected Direct Testimony at 35.

[402] Kollen Corrected Direct Testimony at 35.

[403] Kollen Corrected Direct Testimony at 36.

[404] Fackler Rebuttal Testimony at 6.

[405] Fackler Rebuttal Testimony at 6-7.

This specific adjustment was not mentioned in the Stipulation agreement, but due to the catch all provision KU's original application CWC (lead/lag) calculation methodology including fuel-coal expense is accepted and unchanged.[406]

Having considered the record and being otherwise sufficiently advised, the Commission finds that the Stipulation should be rejected on this point, and KU's CWC (lead/lag) should be modified to remove non-cash Fuel-Coal Expense . The Commission has previously disallowed the inclusion of non-cash fuel-coal expense.[407] KU includes fuel-coal inventories in its balance sheet and is included in rate base already. Removing non-cash fuel-coal expense from KU's updated CWC (lead/lag) results in a reduction to the revenue requirement of $625,542.

<u>Pension and OPEB Related Asset</u>. In its application, KU included $61,216,000 in Account 128, $130,594,000 in Account 182, $2,083,000 in Account 184, $12,154,000 in Account 228.3, and $34,777,000 in Account 254 in its forecast test period.[408] In its updated forecast test period, KU included $61,216,000 in Account 128, $130,369,000 in Account 182, $2,083,000 in Account 184, $12,154,000 in Account 228.3, and $34,777,000 in Account 254.[409]

[406] Amended Stipulation, Section 11.1.

[407] Case No. 2024, *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 Oct. 2, 2025), final Order at 10.

[408] Application, Schedule B-5.2.

[409] Aug. 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule B-5.2.1F.

Prior to the Stipulation, the Attorney General/KIUC argued that KU included three pension and two OPEB related assets in the CWC.[410] The Attorney General/KIUC argued excess trust fund assets should not be included in rate base and that customers are entitled to any reduction in pension costs from realized and unrealized gains and realized earnings.[411] The Attorney General/KIUC stated that KU did not finance the pension amounts in Account 128, nor did customers finance the OPEB amounts in Account 228.3.[412]

The Attorney General/KIUC argued that there is no return on prior service costs included in the calculation of pension costs because it does not reduce the pension obligation or the interest on the entirety of the pension obligation included in the calculation of the pension cost.[413] The Attorney General/KIUC argued that the net actuarial losses of the pension plan should not be included in rate base because the only return included in the calculation of pension cost is the return on the fair value of trust fund assets.[414] The Attorney General/KIUC argued it is not reasonable to subtract OPEB underfunding from rate base because KU includes interest at an actuarial interest rate of 5.30 percent in the calculation of the OPEB cost, but then subtracts the underfunding from rate base so that customers are provided the requested grossed up rate of return of 10.07 percent for KU.[415] The Attorney General/KIUC requested that if the Commission

[410] Kollen Corrected Direct Testimony at 36.

[411] Kollen Corrected Direct Testimony at 38.

[412] Kollen Corrected Direct Testimony at 39.

[413] Kollen Corrected Direct Testimony at 40.

[414] Kollen Corrected Direct Testimony at 41.

[415] Kollen Corrected Direct Testimony at 42.

includes the amounts in Account 128 Prepaid Pension in rate base, then it also should subtract the amounts in Account 228.3 Accumulated Provision for Post Retirement Benefits from rate base, again, as a matter of consistency.[416] The Attorney General/KIUC argued that there is no return on prior service costs included in the calculation of OPEB costs because it does not reduce the pension obligation or the interest on the entirety of the OPEB obligation included in the calculation of the OPEB cost.[417] The Attorney General/KIUC recommended that the Commission reject KU's proposal to include Accounts 128 Prepaid Pension, 182 Regulatory Asset – FAS 158 Pension, and 184 Pension Clearing Account in rate base and subtract the amounts in Accounts 228.3 Accumulated Provision for Post Retirement Benefits and 254 Regulatory Liability – Postretirement from rate base.

The Attorney General/KIUC argued that KU's test year pension clearing accounts be set to zero or removed from rate base because clearing accounts on average should be at zero dollars over time and KU used the actual amounts as of February 28, 2025, and held the amounts constant through the end of the test year.[418]

In rebuttal testimony, KU stated that KU pension and OPEB related assets should be included in rate base and capitalization for several reasons.[419] First, KU stated that these assets and liabilities are cash financed and have been cash financed in a prudent manner.[420] Second, KU stated that KU's customers are receiving the benefit of these

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[416] Kollen Corrected Direct Testimony at 42.

[417] Kollen Corrected Direct Testimony at 43.

[418] Kollen Corrected Direct Testimony at 44-46.

[419] Garrett Rebuttal Testimony at 10.

[420] Garrett Rebuttal Testimony at 10.

cash financings in the form of lower Pension and OPEB expense.[421] Third, KU pointed to where KU, in the 2014 rate case proceedings, agreed to amortize actuarial gains and losses for pensions over a 15-year period.[422] KU argued that these do represent cash items and should be included in rate base.[423] KU stated that net Pension and OPEB related asset and liability is financed the same as utility plant.[424] KU also stated that customers receive compensation for trust fund contributions and earnings in the form of reduced income tax expense.[425] KU stated that it has included all of the Pension and OPEB balance sheet accounts along with the associated pension and OPEB expense accounts to ensure equitable treatment.[426]

KU argued that its decision to clear or reclassify the balances in Account 184 to the respective Pension and OPEB balance sheet accounts would have no impact on total rate base and was, therefore, unnecessary from a forecasting standpoint.[427] KU stated that decision not to set the accounts to zero or reclassify the clearing account balances in the forecasted test year had no effect on the revenue requirement.[428]

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[421] Garrett Rebuttal Testimony at 10.

[422] Case No. 2014-00371, *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates* (Ky. PSC June 30, 2015), Order at 4-5; Case No. 2014-00372, *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates* (Ky. PSC June 30, 2015), Order at 5. The agreement was the result of negotiations with the parties.

[423] Garrett Rebuttal Testimony at 11.

[424] Garrett Rebuttal Testimony at 12.

[425] Garrett Rebuttal Testimony at 12.

[426] Garrett Rebuttal Testimony at 12.

[427] Garrett Rebuttal Testimony at 19.

[428] Garrett Rebuttal Testimony at 20.

These specific adjustments were not mentioned in the Stipulation agreement, but due to the catch all provision, KU's original application rate base calculation methodology is accepted as unchanged, including three pension and two OPEB related assets.[429]

Having considered the record and being otherwise sufficiently advised, the Commission finds that KU's three pension and two OPEB related assets are properly included in rate base, and the Account 184 Pension Clearing Account amounts would have no effect on the revenue requirement. Thus, the Attorney General/KIUC proposed adjustment is rejected.

KU's Regulatory Asset Treatment. In its Application, KU proposed an adjustment to increase capitalization by $1,703,956.[430] In its August 25, 2025 Supplemental Filing, this adjustment was updated to $1,748,073.[431] The Commission is not using the capitalization methodology and is not including an increase to rate base for this amount. Regulatory assets are not automatically part of rate base, as evidenced by KU's exclusion of regulatory assets and liabilities from rate base in its application. Much the same as rate case expense regulatory assets, excluding regulatory assets and liabilities from rate base shares the benefit of these deferrals between shareholders and ratepayers.[432]

Valuation. Pursuant to KRS 278.290(1), the Commission is empowered to "ascertain and fix the value of the whole or any part of the property of any utility," and, in doing so, is

[429] Stipulation, Section 11.1.

[430] Application, Tab 63, Schedule J-1.1/J-1.2.

[431] August 25, 2025 Supplemental Filing, Item 54, Attachment, Sch. J, SCH J-1.1|J-1.2 at 4.

[432] *See* Case No. 2024-00354, *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 Oct. 2, 2025), Order at 4–7.

given guidance by the legislature "in establishing value of utility property in connection with rates," and the Commission must "give due consideration" to a number of factors, including capital structure, original cost and "other elements of value recognized by law" in order to ascertain the value of any property under KRS 278.290 "for rate-making purposes." In its application and stipulation agreement, KU proposed to use the capitalization method to calculate its revenue requirement and required increase. As explained above, the Commission has weighed the evidence filed in the case and finds that KU's base rates should be based on a 13-month average forecasted test period rate base of $6,039,717,587.

Rate Base Description	13 Month Average Forecasted Test Period Per Update	Adjustments	Commission 13 Month Average Forecasted Test Period
Utility Plant in Service	$ 11,184,717,352		$ 11,184,717,352
Property Held For Future Use	1,567,610		1,567,610
Accumulated Depreciation and Amortization	(4,492,924,257)	9,167,208	(4,483,757,049)
Net Utility Plant in Service	6,693,360,704		6,702,527,912
Construction Work in Progress	412,035,926		412,035,926
Cash Working Capital Allowance	152,750,103	(63,242,014)	89,508,088
Other Working Capital Allowances	186,929,884		186,929,884
Customer Advances for Construction	(17,950,562)		(17,950,562)
Deferred Income Taxes	(1,257,643,538)	(2,287,218)	(1,259,930,756)
Investment Tax Credits	(73,402,905)		(73,402,905)
Jurisdictional Rate Base	$ 6,096,079,612	(56,362,025)	$ 6,039,717,587

DEFERRAL ACCOUNTINGS

As part of the Stipulation, the Signing Parties agreed that the Commission should approve deferral accounting treatment for KU for any actual expense amounts above or below the expense levels in base rates for KU for the following items: (A) Storm Restoration Expense; (B) Vegetation Management Expense; (C) Software Implementation Expenses[433]; (D) Pension and OPEB Expense; and (E) De-Pancaking Expense.[434] For these items, KU would establish a regulatory asset for amounts exceeding the base rate level and a regulatory liability for amounts below the base rate level. KU would address recovery of any regulatory assets or liabilities in its next base rate case. KU would make an annual filing with the Commission within 90 days of the end of each calendar year to report on and have Commission review of the deferred storm restoration and vegetation management amounts. Additionally, KU would report on pension and OPEB expense, and de-pancaking in this annual filing. KU argued that each of the identified expenses is either extraordinary in nature, necessary to comply with regulatory requirements, or provide long-term benefits to customers.[435]

The Commission finds that these provisions of the Stipulation should be approved in part, denied in part, or modified as discussed below.

Storm Restoration Expense. In its application, KU proposed to automatically defer all storm restoration expenses over or under the amount in base rates. KU stated that this request was designed to decrease the administrative burden of filing for deferral after

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[433] Note that while this request was not directly mentioned in the Stipulation, approval was requested in the catch-all provision located in Amended Application, Section 11.1.

[434] In-line Inspection and Well Logging Expense applies only to LG&E's gas operations.

[435] KU's Post-Hearing Brief at 17.

every major storm.[436] Generally, deferral accounting may be granted for expenses determined to be extraordinary, non-recurring expense which could not have reasonably been anticipated or included in the utility's planning.

Prior to the Stipulation, the Attorney General/KIUC's witness recommended that the Commission deny recovery of all storm expenses, not deferred to a regulatory asset, unless KU can demonstrate that there are incremental expenses to those in the test year.[437] The Attorney General/KIUC recommended the creation of a storm reserve regulatory asset to track storm expenses above the amount in base rates. The Attorney General/KIUC recommended the Commission authorize KU to defer only incremental major storm expenses, not specifically deferred to a regulatory asset, as charges against the storm reserve and then determine recovery of the storm expenses specifically deferred to the storm reserve in a future base rate proceeding.[438] The Attorney General/KIUC's original recommendation resulted in a reduction in storm expense of $6.056 million and reduced the revenue requirement by $6.082 million.[439]

In rebuttal, KU argued that the proposed deferral accounting treatment does not constitute a double recovery of reasonably incurred storm restoration expenses.[440] Further, KU argued that its method of basing the storm budget on a 5-year average of storm restoration expenses, adjusted for inflation using the Consumer Price Index (CPI), is consistent with its prior cases. In this calculation, large storms that were separately

[436] Conroy Direct Testimony at 9–10.

[437] Kollen Corrected Direct Testimony at 50.

[438] Kollen Corrected Direct Testimony at 50-51.

[439] Kollen Corrected Direct Testimony at 51.

[440] Waldrab Rebuttal Testimony at 7.

tracked through regulatory assets were not included in the 5-year average to avoid inflating the amounts embedded in base rates.[441] KU claimed that removing all expenses out of base rates would be an artificial reduction of storm restoration expenses in the test year, potentially impairing KU's ability to recover legitimate costs.[442]

The Stipulation proposed to accept KU's application request.[443] KU currently has $5.989 million budgeted for jurisdictional storm related O&M expenses embedded in its forecasted test year.[444]

The Commission finds that this provision of the Stipulation should be approved with modifications. The amount of jurisdictional storm damage restoration expenses for the forecasted test year should be $5.989 million. The Commission finds that the proposed automatic regulatory asset or liability treatment for all storm costs above or below the base rate amount is unreasonable. The entirety of these expenses would likely not be eligible for deferral under the current mechanism and as such, the argument that it reduces administrative burden is flawed.

The Institute of Electrical and Electronics Engineers (IEEE) Standard 1366 defines a Major Event Day as any day in which the system's System Average Interruption Duration Index (SAIDI) exceeds the threshold value set by IEEE.[445] The Commission

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[441] Metts Rebuttal Testimony at 12.

[442] Metts Rebuttal Testimony at 12.

[443] Stipulation, Section 4.1.

[444] KU's Response to Staff's Post-Hearing Request, Item 9.

[445] *See* Case No. 2016-00180, *Application of Kentucky Power Company for an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities Related to the Extraordinary Expenses Incurred by Kentucky Power Company in Connection with the Two 2015 Major Storm Events* (Ky. PSC Nov. 3, 2016), Order at 1. A Major Event Day is defined by IEEE Standard 1366 as any day in which the SAIDI exceeds the threshold value of T_{med}. The T_{med} threshold value in turn is calculated at the end of

finds that a Major Event Day under this definition generally meets the standard for an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning.

Therefore, the Commission finds that KU should be allowed to defer storm damage restoration expenses for Major Event Days that exceed $2 million per event and will result in total storm damage expenses that exceed the amounts included in base rates in a calendar year. Further, establishment of a storm damage regulatory liability is not necessary as the Commission does not authorize a tracker. To be clear, KU may establish a regulatory asset for any single major storm event above $2 million without prior Commission approval. However, if before the end of the fiscal year, it is determined that KU has had the good fortune to not expend above the base rate amount for storm damage expenses, KU would be expected to remove from the regulatory asset the amount of storm damage expenses up to the amount in base rates. Further, KU is not authorized to collect into a regulatory asset the combined storm damage expenses for multiple minor storm events, even if those amounts collectively exceed the amount in base rates. The purpose of this approval is to reduce administrative burden on both the utility and regulators, not to eliminate all potential risk for storm damage expenses. Because this approval is only for the regulatory asset treatment of amounts over base rates, the regulatory liability portion of this proposal is denied.

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each reporting period, typically a calendar year, using data from the previous five years. It is calculated by taking the average of natural logarithm of each daily SAIDA during the previous five-year period. The standard deviation of the five-year data set is then determined and the threshold value of T_{med} is set at 2.5 standard deviations. Any day in the subsequent reporting period that exceeds the T med is classified as a Major Event Day.

Vegetation Management Expenses. KU included $31.4 million in vegetation management expenses in the forecasted test year.[446] KU also proposed an adjustment to the test year expenses related to revisions to the estimates included in its 2025 business plan for updated vegetation management initiatives.[447] This adjustment increases test-year maintenance of transmission lines by $2,175,052 and maintenance of overhead lines by $ 7,344,640.[448] This adjustment reduces net income by $7,144,529, after income tax effects.[449] KU requested authority to establish a regulatory asset or liability to automatically defer all expenses over or under the amount in base rates, similar to the proposal for storm restoration expenses.[450] KU explained that there is a relationship between storm restoration and vegetation management costs.[451] KU stated that, as vegetation presents the single largest source of outages particularly during storm events, KU expects that the resilience efforts being undertaken by KU will reduce future storm costs, thereby, reducing reactive vegetation management costs.[452]

Prior to the Stipulation, the Attorney General/KIUC proposed an adjustment to vegetation management expenses which would decrease the revenue requirement by $8.816 million.[453] The Attorney General/KIUC explained that KU budgeted a plan amount

[446] KU's Response to Staff's Third Request, Item 40.

[447] Fackler Direct Testimony at 72.

[448] Application, Exhibit D-2.1 at 3–4.

[449] Application, Exhibit D- 2.1 at 6.

[450] Conroy Direct Testimony at 9–10.

[451] Waldrab Direct Testimony at 25.

[452] Waldrab Direct Testimony at 25.

[453] Kollen Corrected Direct Testimony at 55.

and then added expenses related to target and incremental funding for vegetation management.[454] The Attorney General/KIUC argued that the test-year expenses should only be based on the planned vegetation management and not include adjustments for targets or incremental funding.[455] The Attorney General/KIUC adjustments to vegetation management expense would decrease KU's vegetation management expenses to just the plan amount.[456] The Attorney General/KIUC argued that the plan amount was more in line with historical averages.[457] The Attorney General/KIUC argued that the increases for targets and incremental funding were unsupported.[458] The Attorney General/KIUC also argued that deferral accounting was not necessary for these expenses.[459]

In rebuttal, KU argued that increases to vegetation management expenses were necessary to fully fund the work needed to meet KU's goals for customer interruptions and to reduce storm damage restoration expenses.[460] KU stated that tree-related outages accounted for 30 percent of all customer interruptions from 2019 through 2023.[461] KU argued that its budgets for vegetation management are developed to decrease outages during severe weather events, in line with industry best practices.[462]

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[454] Kollen Corrected Direct Testimony at 54.

[455] Kollen Corrected Direct Testimony at 55.

[456] Kollen Corrected Direct Testimony at 55.

[457] Kollen Corrected Direct Testimony at 53.

[458] Kollen Corrected Direct Testimony at 54.

[459] Kollen Corrected Direct Testimony at 52.

[460] Rebuttal Testimony of Peter Waldrab (Waldrab Rebuttal Testimony) (filed Sept. 30, 2025) at 5.

[461] Waldrab Rebuttal Testimony at 2.

[462] Waldrab Rebuttal Testimony at 3.

The proposal to automatically defer all expenses over or under the amount in base rates was included in the original filing; however, the Stipulation proposed to accept the Attorney General/KIUC's adjustment and remove test-year expenses of $8.8 million in vegetation management expenses for KU.[463]

The Commission finds that the request to establish a regulatory asset and liability to automatically defer all vegetation management expenses over or under the amount in base rates should be denied as KU should be able to budget and control these expenses. KU has not demonstrated that, over time, its proposal will result in a savings that fully offset the costs. The Commission finds that these expenses are not extraordinary, non-recurring expenses qualifying for deferral accounting. The Commission also finds that the request for regulatory asset treatment was not based on a statutory or administrative directive or an industry sponsored initiative, as KU did not put forth evidence related to these alternative reasonings.

The Commission also finds, specifically, that the request to remove test year expenses of $8.8 million for KU in the Stipulation should be denied. The Commission also finds that KU's adjustment to test year expense from the August 25, 2025 Supplemental Filing to the amended forecasted test year should be accepted. Therefore, the amount of vegetation management expenses for the forecasted test year should be $31.4 million, which is the amount KU originally included in its forecasted test year.

Software Implementation Expenses. In its application, KU proposed to defer software implementation expenses and amortize the resulting regulatory asset over the

[463] Stipulation, Article 2.2(D)..

lives of the underlying software.[464] Expenses that KU requested deferred accounting for included training; data conversion and migration; direct business or functional process reengineering incurred associated with strategic implementations; change management; preliminary project stage; hyper care; and cloud computing such as hosting and other fees during implementation.[465] KU admitted that this request is in contradiction to FERC accounting rules[466] to expense these costs.[467] KU stated that, without the FERC accounting rules to the contrary, these costs would be capitalized and recovered over the life of the asset.[468] KU stated that the amount in the forecasted test year is $9.3 million.[469] The total estimated costs that KU plans to defer through 2029 are approximately $15.2 million.[470] The amortization expense included in the forecasted test year was approximately $47,000 for KU.[471] KU also provided the depreciable lives for the underlying assets and noted that the amortization would only begin when the underlying asset is placed into service.[472]

[464] Garrett Direct Testimony at 10–12.

[465] Garrett Direct Testimony at 10.

[466] *See* Accounting Standards Update (ASU) No. 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement* and FERC Docket No. AI 20-1-000*, Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract*. *See also* Accounting Standards Codification (ASC) 350-40-25-1, ASC 350-40-25-2, ASC 350-45-3, ASC 350-40-25-4, ASC 350-40-25-5, and ASC 350-40-25-6.

[467] Garrett Direct Testimony at 11.

[468] Garrett Direct Testimony at 10.

[469] Garrett Direct Testimony at 13.

[470] Garrett Direct Testimony at 11.

[471] Garrett Direct Testimony at 11.

[472] KU's Response to Staff's Third Request, Item 41.

No intervenor took a position on this request. The Stipulation does not comment on this deferral but it was included as part of the catch-all provision.[473]

The Commission finds that deferral accounting should be approved because otherwise the implementation costs would be expensed in a single year. Because the expenses are nonrecurring, the Commission would normalize the expenses over the life of the underlying asset. Deferral accounting will similarly smooth recovery from ratepayers but better match revenues and expenses. In other words, the recovery of the expenses would be the same regardless of deferral accounting, but the time period in which KU expenses these items would not match the revenues without deferral accounting. Deferral accounting will allow KU to expense the costs at the same time that it records the revenue. The Commission finds that these expenses, limited to the implementation costs described above, are extraordinary, non-recurring expenses that qualify for deferral accounting. To be clear, the Commission recognizes this accounting treatment benefits rate payers but nothing in this section should be construed as relieving KU from ensuring it complies with all applicable accounting rules and regulations.

The Commission grants the deferral accounting only for the amounts through December 31, 2026, and approves the amortization period over the lives of the underlying software The Commission further finds that the amortization expense associated with this period contained in the forecasted test period is reasonable and should be accepted A regulatory asset's amortization must be included in rates to properly qualify for deferral

[473] Amended Stipulation at 2.

accounting.[474] A regulatory asset is created when a rate-regulated business is authorized by its regulatory authority to capitalize an expenditure that under traditional accounting rules would be recorded as a current expense; the reclassification of an expense to a capital item allows the regulated business the opportunity to request recovery in future rates of the amount capitalized.[475] Without the amortization of the regulatory asset being included in rates, there is no asset.

Additionally, the Commission notes that KU provided estimated amounts related to IT implementation Expenses. The Commission will review the reasonableness of any implementation costs beyond the estimate amounts in the next rate base. This is to limit the impact of the deferral and better match the revenues from the amortization and the amortization expense.

<u>Pension and OPEB Expenses</u>. In the forecasted test year, KU included $0.842 million and $0.024 million in pension and OPEB expenses, respectively.[476] KU did not propose any deferral accounting treatment related to pension and OPEB expenses in its application.

Prior to the Stipulation, the Attorney General/KIUC proposed an adjustment to reduce Pension and OPEB expenses to 2024 actuals and to defer any amounts under or over the base rate amounts.[477] This deferral would create a regulatory liability or regulatory asset, respectively. The Attorney General/KIUC stated that the forecasted

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[474] *See* Case No. Case No. 2008-00436, *Application of East Kentucky Power Cooperative, Inc. for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to Certain Replacement Power Costs Resulting from Generation Forced Outages* (Ky. PSC Dec. 23, 2008).

[475] Case No. 2008-00436, Dec. 23, 2008 Order at 3-4.

[476] KU's Response to the Attorney General/KIUC's First Request, Item 70d.

[477] Kollen Corrected Direct Testimony at 60–61 and 62–63.

expenses were overstated and recommended reducing Pension and OPEB expenses to reduce the revenue increase by $5.330 million and $0.532 million, respectively.[478] This adjustment applies only to the test-year expense.

In rebuttal testimony, KU argued that the Pension and OPEB expenses were budgeted using its annual business planning and most recent actuarial data.[479] KU provided updated Pension and OPEB expenses using updated information which predicted an increase in these expenses.[480]

The Signing Parties to the Stipulation agreed to accept the Attorney General/KIUC's adjustment reduce the base rate expense amount by $1.3 million and defer any difference from base rates for consideration in KU's next base rate case.[481] This difference would establish either a regulatory asset or a regulatory liability.

The Commission finds that this provision of the Stipulation should be accepted, in part, and denied, in part. The Commission finds that KU's request for deferral accounting related to Pension and OPEB expenses should be approved. KU forecasted these expenses based on best practices and normal budgeting guidelines. These expenses are volatile, and KU is not in control of the final expense. Deferral accounting will protect customers and KU from the fluctuations in these expenses and allow for smoother recovery. The Commission approves the Stipulation provision allowing KU to defer the amounts above or below the amount in base rates. However, reducing test-year

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[478] Kollen Corrected Direct Testimony at 61 and 63.

[479] Rebuttal Testimony of Christopher Garrett (Garrett Rebuttal Testimony) (filed Sept. 30, 2025) at 14.

[480] Garrett Rebuttal Testimony at 15–16.

[481] Stipulation, Article 2.2(E) and Article 4.

expenses unnecessarily inflates the regulatory asset/liability, and the Commission finds that the adjustment to the base rate amount, agreed to in the Stipulation, is denied. In the forecasted test year, KU included $0.842 million and $0.24 million in pension and OPEB expenses, respectively,[482] but did not request deferral accounting. Therefore, the test year-expenses included in base rates should be $0.842 million and $0.24 million for Pension and OPEB expenses, respectively.

De-pancaking Expense. In its 2018 rate case, KU agreed to track merger mitigation de-pancaking (MMD) costs and defer to a regulatory liability any reduction in these expenses caused by a reduction or elimination of the MMD component of FERC transmission rates that KU pays.[483] KU stated that it will continue to accumulate and defer for future return any incremental collections above the amounts currently embedded in base rates for costs incurred for MMD expenses.[484] KU stated that this will result in any overcollection of costs being returned to customers should reductions occur in the future.[485] KU proposed to also track and defer to a regulatory asset any increases in the MMD expenses "for harmonization purposes," net of any Open Access Transmission revenue offsets.[486]

Prior to the Stipulation, the Attorney General/KIUC argued that test year MMD expenses were overstated and should be based on the amounts in the base year,

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482 KU's Response to the Attorney General/KIUC's First Request, Item 70d.

483 Garrett Direct Testimony at 15.

484 Application at 14.

485 Application at 14.

486 Garrett Direct Testimony at 15.

escalated for inflation.[487] This adjustment resulted in a revenues requirement reduction of $2.456 million.[488]

In rebuttal testimony, KU stated that the increases in the test year were supported by sufficient evidence and provided a breakdown of the drivers of the increase.[489] KU also stated again that the regulatory asset treatment for amounts over base rates was appropriate to refine the mechanism.[490]

The Signing Parties to the Stipulation agreed to defer amounts above base rates, consistent with the Application, and remove $6.3 million in test year expenses.[491]

The Commission finds that this provision of the Stipulation should be denied. The Commission finds that the decrease in these expenses and the proposal to defer amounts in excess of base rates should be denied. The Commission finds that KU's original proposal to defer any amount above base rates should also be denied. KU agreed to only defer amounts below base rates in a prior settlement and did not justify the deferral of the amounts in excess of base rates. KU should continue to defer any amounts below the base rate expense. KU has not presented sufficient evidence that these are non-recurring, extraordinary expenses that could not have reasonably been anticipated or included in the utility's planning; or that over time this will result in savings that fully offset the costs. The Commission also finds that the request for regulatory asset treatment was not based on a statutory or administrative directive or an industry sponsored initiative, as

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[487] Futral Direct Testimony at 20.

[488] Futral Direct Testimony at 21.

[489] Rebuttal Testimony of Heather Metts (Metts Rebuttal Testimony) (filed Sept. 30, 2025) at 5–7.

[490] Metts Rebuttal Testimony at 7–8.

[491] Stipulation, Article 2.2(E) and Article 4..

KU did not put forth evidence related to these alternative possible criteria. The Commission finds that the argument that a regulatory asset should be granted for harmonization purposes is not compelling. Therefore, these expenses do not meet the criteria for regulatory asset treatment.

Amortization Periods for Approved Regulatory Assets/Liabilities

Advanced Metering Infrastructure (AMI) Implementation. In Case No. 2020-00349, the Commission approved KU's proposal to install AMI meters and to create regulatory assets and liabilities related to the implementation of the new meters.[492] KU was ordered to make quarterly filings regarding the implementation of AMI meters and annual filings regarding the realized benefits of the AMI system.

As of October 31, 2025, LG&E/KU have provided 17 quarterly reports on the implementation of the AMI meters. In the October 31, 2025 report, covering the period through September 30, 2025, KU stated that they have installed 589,864 AMI meters and retired 561,649 non-AMI meters.[493] LG&E/KU stated that they are on track to complete full deployment by December 31, 2025.[494] LG&E/KU reported they had expended $38.7 million in implementation costs.[495]

As of July 31, 2025, LG&E/KU have provided four annual reports on the benefits of the AMI project. These reports provide the plan and progress toward maximizing

[492] Case No. 2020-00349, *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* (Ky. PSC June 30, 2021), Order at 13.

[493] Case No. 2020-00349, Seventeenth AMI Quarterly Report (filed Oct. 31, 2025) at 2.

[494] Case No. 2020-00349, Seventeenth AMI Quarterly Report at 1.

[495] Case No. 2020-00349, Seventeenth AMI Quarterly Report at 1.

benefits in the areas of reduced meter reading expense; ability to disconnect/reconnect remotely; reduced field service costs; avoided meter costs; fuel savings from decreased customer usage; conservation voltage reduction; time of day rates; electric distribution operations; improved outage response; management and prediction of outages, overloads, and shortfalls of transmission and distribution assets; data availability to customers within 4-6 hours; innovative rate design; reduced theft and earlier detection; a detailed plan for customer engagement of its AMI systems as well as 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 system's interaction with LG&E/KU's other smart grid investments, including the outage management system.[496] Through December 2024, LG&E/KU had recorded approximately $11 million in reduced meter reading expenses and $1.2 million in reduced field service expenses to a regulatory liability.[497] LG&E/KU stated that, through December 2024, LG&E/KU had realized $6.9 million in savings from avoided meter replacement costs.[498] LG&E/KU stated that they also reduced the regulatory liability by $1.7 million in decreased reconnection revenues due to remote disconnections and reconnections.[499] LG&E/KU stated that conservation voltage reduction, electric distribution operations costs reductions, and outage detection benefits would not begin until the AMI system was fully integrated in 2026.[500] LG&E/KU stated that customers

[496] Case No. 2020-00349, Fourth Annual AMI Report (filed July 31, 2025) at 1.

[497] Case No. 2020-00349, Fourth Annual AMI Report at 1–2.

[498] Case No. 2020-00349, Fourth Annual AMI Report at 2.

[499] Case No. 2020-00349, Fourth Annual AMI Report at 1.

[500] Case No. 2020-00349, Fourth Annual AMI Report at 1–3.

receive AMI data within 4–6 hours and they have developed a robust customer engagement plan to inform customers of the deployment and uses of the AMI system, along with alternative rates available such as time of use rates[501]

KU proposed amortization periods for existing regulatory assets and liabilities related to the implementation of AMI meters. The regulatory assets are comprised of 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 KU's weighted average cost of capital and that calculated using the methodology approved by FERC.[502] KU's AMI regulatory asset is $40.1 million.[503] KU also recorded regulatory liabilities for the difference between actual meter reading expenses and those included in base rates in its last rate case. These regulatory liabilities total $17.1 million for KU.[504] KU proposed to amortize the regulatory assets over 15 years and the regulatory liabilities over five years.[505] The asymmetrical amortization periods are meant to recover the regulatory assets over the life of the AMI meters and return the liabilities over a shorter period to mitigate the rate impact because the regulatory liability amortization will offset

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[501] Case No. 2020-00349, Fourth Annual AMI Report at 2 and 4–5.

[502] Garrett Direct Testimony at 13.

[503] Garrett Direct Testimony at 14.

[504] Garrett Direct Testimony at 14.

[505] Garrett Direct Testimony at 14.

the regulatory asset amortization.[506] No intervenor commented on the amortization periods for these regulatory liabilities and assets.

The Commission finds that these amortization periods are reasonable and should be approved. The Commission finds that a 15-year amortization period for the regulatory assets and a five-year amortization period for the regulatory liabilities is reasonable. Amortizing the regulatory assets over the life of the underlying assets is reasonable. Using an asymmetrical amortization period of five years for the regulatory liabilities will lessen the rate impact of the regulatory asset recovery. The Commission also finds that KU has, to this point, complied with the reporting requirements set forth in Case No. 2020-00349. KU should continue to file the quarterly reports until such time as AMI is completely implemented. KU should continue to file the annual reports. KU should include information and testimony about the AMI implementation and integration in its next base rate filing including addressing such items as the effect of the reduction in disconnect and reconnect fees, conservation voltage reduction, electric distribution operations costs reductions and the impact or effectiveness of the customer engagement program.

[506] Garrett Direct Testimony at 14.

Prior Deferred Storm Damage Expenses. In Case Nos. 2023-00093,[507] 2024-00181,[508] 2024-00329,[509] and 2025-00025,[510] the Commission authorized KU to defer storm damage restoration expenses. These regulatory assets were approved for accounting purposes only. The total balances of these regulatory assets are $11,016,643, $4,998,332, $8,400,230, and $7,592,273, respectively.[511] These amounts are the actual deferrals for the incremental costs of storm damage restoration.

KU proposed to amortize its current regulatory assets for storm damage over five years, consistent with prior storm damage regulatory assets.[512] The total balance for KU for all four regulatory assets is $32,007,478.[513]

No intervenor took a position on these regulatory assets or the proposed amortization period. The Stipulation did not specifically address this, but the request would have been approved by the catch all provision.

The Commission finds that the proposed amortization period for storm damage regulatory assets is reasonable and should be approved, consistent with prior storm

[507] Case No. 2023-00093, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Approving the Establishment of Regulatory Assets* (Ky. PSC April 5, 2023).

[508] Case No. 2024-00181, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Approving the Establishment of Regulatory Assets* (Ky. PSC Nov. 21, 2024).

[509] Case No. 2024-00329, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Approving the Establishment of Regulatory Assets* (Ky. PSC Dec. 4, 2024).

[510] Case No. 2025-00025, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Approving the Establishment of Regulatory Assets* (Ky. PSC Mar. 19, 2024).

[511] Garrett Direct Testimony at 9.

[512] Garrett Direct Testimony at 9.

[513] Garrett Direct Testimony at 9.

damage regulatory assets. A five-year amortization period balances the need for KU to recover these expenses and the rate impact to ratepayers. The impact of this amortization is a test-year amortization expense of $6,401,496.

Glendale Megasite. KU received approval to defer the amounts paid to Nolin Rural Electric Cooperative Corporation (Nolin RECC) and East Kentucky Power Cooperative, Inc. (EKPC) to acquire the territory to serve a large industrial customer, BlueOval SK, LLC.[514] The regulatory asset consists of the consideration paid to Nolin RECC in exchange for the territory modification and the amount paid by KU to reimburse Nolin RECC and EKPC for removal of their existing facilities.[515] The regulatory asset totals $8,626,220 million,[516] and KU requested to amortize this amount over five years, consistent with the period used for storm damage regulatory assets.[517]

No intervenor took a position on this regulatory asset or the proposed amortization period. The Stipulation did not address this issue but would have been approved by the catch all provision.

The Commission finds that the proposed amortization period for this regulatory asset is reasonable, consistent with other regulatory assets, and should be approved. A five-year amortization period balances the need for KU to recover these expenses and

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[514] Case No. 2021-000462, *Electronic Joint Application of Kentucky Utilities Company, Nolin Rural Electric Cooperative Corporation, and East Kentucky Power Cooperative, Inc. for Approval of an Agreement Modifying an Existing Territorial Boundary Map and Establishing the Retail Electric Supplier for Glendale Megasite in Hardin County, Kentucky* (Ky. PSC Jan. 27, 2022).

[515] Garrett Direct Testimony at 14.

[516] KU's Response to the Attorney General/KIUC's First Request, Item 39.

[517] Garrett Direct Testimony at 15.

the rate impact to ratepayers. The impact of this amortization is a test-year amortization expense of $1,725,244 million.

RATE OF RETURN

Return on Equity (ROE)

The ROE analyses for KU, LG&E's gas operations, and LG&E's electric operations were performed concurrently by all parties in this proceeding and, as such, the below discussion references both LG&E and KU. No variances exist between the below discussion and the ROE discussions in the final Orders for electric and gas operations in Case No. 2025-00114.[518] All discussion of Signing Parties' arguments and recommendations prior to the Stipulation discussion below reflect the party's pre-stipulation positions.

In their applications, LG&E/KU used multiple models to develop their recommended ROE, including the Discounted Cash Flow (DCF) Model, Risk Premium Model (RPM), and Capital Asset Pricing Model (CAPM) (collectively, Models).[519] LG&E/KU applied the Models to a proxy group of seven natural gas utilities (Natural Gas Proxy Group), a proxy group of 15 vertically integrated electric utilities (Electric Proxy Group), as well as two proxy groups of 49 and 47 domestic, non-price regulated companies (Non-Price Regulated Proxy Groups) which they argued were comparable in total risk to the Natural Gas Proxy Group and Electric Proxy Group, respectively.[520]

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[518] Case No. 2025-00114, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and Approval of Certain Regulatory and Accounting Treatments* (filed May 30, 2025).

[519] Direct Testimony of Dylan W. D'Ascendis (D'Ascendis Direct Testimony) at 3.

[520] D'Ascendis Direct Testimony at 3.

The companies selected for the proxy groups met a list of eight criteria for the Electric Utility Proxy Group and seven criteria for the Natural Gas Proxy Group.[521] Additionally, LG&E/KU relied on the Predictive Risk Premium Model (PRPM) in their estimation of the equity risk premium used in their RPM and CAPM analyses,[522] as well as the Empirical CAPM (ECAPM) applied to the Utility Proxy Groups which they averaged with the results of their CAPM analysis.[523] LG&E/KU's results from the Models ranged from 10.29 percent to 11.92 percent and 10.32 percent to 11.84 percent for the Natural Gas Proxy Group and Electric Proxy Group, respectively, which were then adjusted based on company-specific risk factors.[524] The adjustments to the common equity cost rate model results included a size adjustment and flotation cost adjustment,[525] as well as a credit risk adjustment as it relates to the Electric Utility Proxy Group.[526] After these adjustments, the common equity cost rates ranged from 10.59 percent to 12.22 percent for the Natural Gas Proxy Group and 10.46 percent to 11.98 percent and 10.51 percent to 12.03 percent for the Electric Utility Proxy Group for KU and LG&E, respectively.[527] From those ranges, LG&E/KU recommended an ROE of 10.95 percent for ratemaking purposes for both LG&E's electric and natural gas operations and KU's electric

[521] D'Ascendis Direct Testimony at 13-16.

[522] D'Ascendis Direct Testimony at 31.

[523] D'Ascendis Direct Testimony at 39-40.

[524] D'Ascendis Direct Testimony at 4.

[525] D'Ascendis Direct Testimony at 4.

[526] D'Ascendis Direct Testimony at 57.

[527] D'Ascendis Direct Testimony at 4-5.

operations.[528] The estimated ROE results and adjustments are shown in the table below:[529]

	LG&E		KU
	Gas Proxy Group	Electric Proxy Group	Electric Proxy Group
Discounted Cash Flow Model	10.29%	10.32%	10.32%
Risk Premium Model	10.86%	10.79%	10.79%
Capital Asset Pricing Model	11.12%	10.75%	10.75%
Market Models Applied to Comparable Risk, Non-Price Regulated Companies	11.92%	11.84%	11.84%
Indicated Range of Common Equity Cost Rates Before Adjustments for Company-Specific Risk	10.29% - 11.92%	10.32% - 11.84%	10.32% - 11.84%
Size Adjustment	0.15%	0.10%	0.05%
Credit Risk Adjustment	0.00%	-0.07%	-0.07%
Flotation Cost Adjustment	0.15%	0.15%	0.15%
Indicated Range of Common Equity Cost Rates after Adjustment	10.59% - 12.22%	10.51% - 12.03%	10.46% - 11.97%
Recommended Cost of Common Equity	10.95%	10.95%	10.95%

The Attorney General/KIUC provided alternative ROE estimates using the CAPM and DCF model applied to both a proxy group of 12 regulated electric utilities and a proxy group of seven gas distribution utilities.[530] The Attorney General/KIUC recommended an ROE of 9.60 percent, which they argued, given LG&E/KU's credit ratings, is just and reasonable for the low-risk electric and gas utility operations of the companies.[531] Additionally, the Attorney General/KIUC recommended the Commission apply a 10 basis point reduction for the Environmental Cost Recovery (ECR) rider ROE, for an ECR ROE

[528] D'Ascendis Direct Testimony at 15.

[529] D'Ascendis Direct Testimony, Table 1 at 4.

[530] Direct Testimony of Richard A. Baudino (Baudino Direct Testimony) (filed Aug. 29, 2025) at 3.

[531] Baudino Direct Testimony at 34-35.

of 9.50 percent.[532] The Attorney General/KIUC also recommended that, if the Commission decides to continue the Gas Line Tracker (GLT) in this proceeding, the Commission apply a 10 basis point reduction to investments included in the GLT, for a GLT ROE of 9.50 percent as well.[533] The following tables summarize the Attorney General's ROE results for both its Electric Utility Proxy Group and Gas Utility Proxy Group.[534]

Electric Utility Proxy Group	
DCF Methodology	
Method 1:	
High	10.51%
Low	8.56%
Average	9.70%
Method 2:	
High	10.35%
Low	9.11%
Average	9.94%
CAPM Methodology	
Forward-looking Market Return	9.10%
Historical Risk Premium:	
Arithmetic Mean	10.04%
Supply Side MRP	9.30%
Supply Side Less WWI Bias	8.63%
IESE MRP Survey	8.77%
KMPG MRP	8.59%
Kroll MRP	8.77%
Damodaran MRP	7.91%
Average CAPM Results	8.89%
Average CAPM Excluding High and Low	9.02%
CAPM Midpoint	8.98%
CAPM Midpoint Excluding High and Low	8.95%

[532] Baudino Direct Testimony at 40.

[533] Baudino Direct Testimony at 41.

[534] Baudino Direct Testimony at 33, Table 1 and 34, Table 2.

Gas Utility Proxy Group	
DCF Methodology	
Average Growth Rates:	
High	11.52%
Low	7.69%
Average	10.17%
Midpoint	9.61%
Median Growth Rates:	
High	11.59%
Low	8.13%
Average	10.21%
Midpoint	9.86%
CAPM Methodology	
Forward-looking Market Return	9.52%
Historical Risk Premium:	
Arithmetic Mean	10.56%
Supply Side MRP	9.74%
Supply Side Less WWI Bias	9.01%
IESE MRP Survey	9.16%
KMPG MRP	8.96%
Kroll MRP	9.16%
Damodaran MRP	8.22%
Average of CAPM Range	9.29%
Midpoint of CAPM Range	9.39%
Average Excluding High and Low	9.26%
Midpoint Excluding High and Low	9.35%

The Attorney General/KIUC argued that LG&E/KU's recommended ROE of 10.95 percent grossly overstates the investor required return for regulated utilities and is significantly biased upward.[535] Additionally, the Attorney General/KIUC argued that LG&E/KU's recommended ROE would significantly inflate LG&E/KU's revenue requirement and harm Kentucky electric and gas ratepayers.[536] The Attorney General/KIUC also argued that LG&E/KU's ROE recommendation represents an extreme

[535] Baudino Direct Testimony at 4.

[536] Baudino Direct Testimony at 4.

outlier when compared to recent commission-approved ROEs.[537] With regard to LG&E/KU's DCF analysis, the Attorney General/KIUC argued that, because dividend payments are such a significant portion of the total return to utility shareholders, forecasted dividend growth should have been considered in addition to earnings growth forecasts.[538] Additionally, the Attorney General/KIUC argued that it is crucial to consider the lower dividend growth forecasts for both proxy groups in this proceeding due to the unsustainably high earnings growth forecasts from Standard and Poor's (S&P) Capital IQ and Zacks Investment Research, and argued that using only earnings growth forecasts would lead to a significant overstatement of the ROE results from the DCF model.[539]

Regarding the RPM, the Attorney General/KIUC argued that the bond yield plus risk premium approach is imprecise and can only provide very general guidance on the current authorized ROE for a regulated electric utility and that a properly formulated DCF model using current stock prices and growth forecasts is far more reliable and accurate.[540] The Attorney General/KIUC argued that LG&E/KU's RPM analyses are based on historical risk premium analyses that may have no relevance in today's marketplace, and they systematically overstated its risk premiums with regard to their use of more forward-looking analyses, both of which led to excessive market risk premium ROEs for their electric and gas operations.[541] The Attorney General/KIUC also argued that LG&E/KU did not show that their PRPM is relied upon by investors to determine their required ROE

[537] Baudino Direct Testimony at 42.

[538] Baudino Direct Testimony at 14.

[539] Baudino Direct Testimony at 14

[540] Baudino Direct Testimony at 45.

[541] Baudino Direct Testimony at 45.

for regulated electric and gas utilities, nor did they demonstrate that their PRPM is a widely accepted approach by regulatory commissions.[542] Additionally, the Attorney General/KIUC cited to past Commission cases in which the Commission rejected the use of the PRPM, as well as commissions in other jurisdictions, and recommended the Commission reject the use of the PRPM in this proceeding.[543]

The Attorney General/KIUC argued that LG&E/KU's CAPM result using the prospective S&P 500 market risk premium is totally implausible given current financial market conditions and that LG&E/KU's methodology is fatally flawed if it produces that kind of CAPM ROE result, and argued that the source of the ROE overstatement is excessive earnings growth rates.[544] Additionally, the Attorney General/KIUC argued that the use of ECAPM to correct the CAPM results for companies with betas less than 1.0 is another indication that the model is not sufficiently accurate.[545] Finally, the Attorney General/KIUC argued that LG&E/KU's use of unregulated companies as proxies for regulated companies, and the inclusion of size adjustments and flotation cost adjustments, are inappropriate and should be rejected.[546]

The DOD/FEA employed multiple DCF models, including a Constant Growth DCF Model, Sustainable Growth DCF Model, Multi-Stage Growth DCF Model, which indicated a fair ROE for LG&E/KU in the range of 8.90 percent to 9.50 percent, with a midpoint of

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[542] Baudino Direct Testimony at 49.

[543] Baudino Direct testimony at 50-51.

[544] Baudino Direct Testimony at 58.

[545] Baudino Direct Testimony at 58.

[546] Baudino Direct Testimony at 59–63.

9.20 percent.[547] The results of the DOD/FEA's DCF analyses are summarized in the table below:[548]

Summary of DCF Results						
	Gas		Electric		Combined	
Description	Average	Median	Average	Median	Average	Median
Constant Growth DCF Model (Analysts' Growth)	10.83%	10.41%	10.83%	10.41%	11.04%	10.77%
Constant Growth DCF Model (Sustainable Growth)	9.21%	8.68%	9.21%	8.68%	9.34%	9.05%
Multi-Stage Growth DCF Model	8.78%	8.42%	8.78%	8.42%	8.75%	8.47%
Average	9.61%	9.17%	9.61%	9.17%	9.71%	9.43%

The DOD/FEA relied on the same Natural Gas Proxy Group and Electric Utility Proxy Group developed by LG&E/KU, with the exception of the exclusion of TXNM Energy due to it entering into an agreement to be acquired by Blackstone Energy.[549] Additionally, the DOD/FEA relied on a Combination Proxy Group, which they argued is reasonably comparable in investment risk to LG&E/KU due to their average credit rating and common equity ratio, and argued that their Combination Proxy Group would produce conservative ROE estimates.[550] Additionally, the DOD/FEA performed an RPM analysis

[547] Direct Testimony of Michael Gorman (Gorman Direct Testimony) (filed Aug. 29, 2025) at 49, Table 7.

[548] Gorman Direct Testimony at 49, Table 7.

[549] Gorman Direct Testimony at 30.

[550] Gorman Direct Testimony at 31-32.

which supported a risk-premium based ROE for LG&E/KU in the range of 9.70 percent to 9.85 percent with a midpoint of 9.77 percent,[551] as well as a CAPM analysis which indicated a CAPM return estimate of 9.85 percent.[552]

The DOD/FEA recommended an ROE in the range of 9.20 percent to 9.80 percent for LG&E/KU, with a point estimate of 9.50 percent, which they argued reflects observable market evidence, the impact of the Federal Reserve's policies on current and expected long-term capital market costs, an assessment of the current risk premium built into current market securities, and a general assessment of the current investment risk characteristics of the regulated utility industry and the market's demand for utility securities.[553] Additionally, the DOD/FEA stated that they recognized the overweight of common equity in forming their recommended ROE in this case.[554] A summary of the DOD/FEA's ROE results is shown in the table below:[555]

Return on Common Equity Summary	
Description	Results
DCF	9.20%
Risk Premium	9.75%
CAPM	9.85%

[551] Gorman Direct Testimony at 57.

[552] Gorman Direct Testimony at 65.

[553] Gorman Direct Testimony at 65-66.

[554] Gorman Direct Testimony at 3.

[555] Gorman Direct Testimony at 65, Table 9.

The DOD/FEA argued that LG&E/KU's recommended ROE substantially exceeds a fair return and would unjustifiably inflate LG&E/KU's rates above a just and reasonable level.[556] Additionally, the DOD/FEA argued that LG&E/KU's estimated unadjusted market return is significantly overstated, based on their use of unsustainable growth rate estimates in their DCF analyses, and overstated risk premium estimates for both their risk premium and CAPM models.[557] The DOD/FEA also argued that LG&E/KU's unadjusted market return proposed ROE adders in the range of 13 to 30 basis points are not cost-justified and further inflate LG&E/KU's recommended ROE and should be rejected.[558]

The DOD/FEA argued that there were several problems with LG&E/KU's proposed size adjustment, including that LG&E/KU applied the size adjustment without considering the average capitalization of the proxy groups relative to the capitalization structures that support LG&E/KU, the companies' parent company, PPL.[559] The DOD/FEA argued that, therefore, LG&E/KU's size adjustment is not justified because they have not accurately measured the corporate structure which owns the companies.[560] The DOD/FEA argued that the size adjustment is not risk comparable to LG&E/KU and should be rejected.[561] Additionally, the DOD/FEA argued that LG&E/KU's proxy groups are a reasonable risk proxy to the companies, and their proposed downward credit risk adjustment is not

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[556] Gorman Direct Testimony at 4.

[557] Gorman Direct Testimony at 72.

[558] Gorman Direct Testimony at 72.

[559] Gorman Direct Testimony at 75.

[560] Gorman Direct Testimony at 75.

[561] Gorman Direct Testimony at 76.

justified and should be rejected.[562] The DOD/FEA also argued that LG&E/KU's proposed flotation cost adjustment is not based on the recovery of prudent and verifiable actual flotation costs incurred by LG&E/KU, and therefore, is not based on known and measurable costs making it unreasonable.[563]

With regard to LG&E/KU's DCF return estimates, the DOD/FEA argued that the growth rate is excessive and cannot reasonably be expected to last in perpetuity, which is the time period that is assumed by the constant growth DCF model.[564] Additionally, the DOD/FEA argued that company growth rates that exceed the growth rate of Gross Domestic Product (GDP) in the economy in which a company provides goods and services cannot be sustained and that, over time, even with extended capital investment, growth rates will slow and it is therefore necessary to consider a multi-stage DCF model, which reflects a sustainable growth rate.[565] The DOD/FEA also argued that they corrected LG&E/KU's DCF model to a multi-stage DCF model and argued that a reasonable DCF return, applying both LG&E/KU's DCF model and a multi-stage DCF model, is approximately 9.40 percent.[566]

With regard to the RPM, the DOD/FEA argued that LG&E/KU's regression model assumed that there is a simplistic inverse relationship between risk premiums and interest rates, that LG&E/KU's analysis simply ignores investment risk differentials, and that the ROEs that LG&E/KU use are authorized by commissions, and are therefore not directly

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[562] Gorman Direct Testimony at 78.

[563] Gorman Direct Testimony at 79.

[564] Gorman Direct Testimony at 80.

[565] Gorman Direct Testimony at 80-81.

[566] Gorman Direct Testimony at 81.

adjusted by market forces.[567] The DOD/FEA also argued that LG&E/KU's PRPM should be disregarded because it has not been demonstrated that the proposed comparison between the annual volatility on the total returns of equities and the annual volatility of Treasury bond yield produces an accurate historical database in order to draw projections of return volatility going forward, and that LG&E/KU's methodology is based on a mismatch of total returns for stocks compared to a return on bond yield investments only.[568]

The DOD/FEA disagreed with several aspects of LG&E/KU's methodology regarding the CAPM, arguing that the market risk premium is excessive and unreliable due to the unsustainable growth rates LG&E/KU used to develop a market return, and that LG&E/KU's market risk premium estimates suffer from many flaws, including the reliance on the unproven PRPM methodology.[569] Additionally, the DOD/FEA argued that the Commission should reject LG&E/KU's ECAPM because their adjustment to the beta values is duplicative of the adjustments the ECAPM already makes to correct for any shortcomings of the traditional CAPM, resulting in overstated results.[570] Finally, the DOD/FEA argued the Commission should reject the use of LG&E/KU's non-price regulated proxy groups, as LG&E/KU have not proven that these companies are risk-comparable to LG&E/KU, and the ROE estimates based on the non-utility proxy group do

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[567] Gorman Direct Testimony at 85-87.

[568] Gorman Direct Testimony at 82

[569] Gorman Direct Testimony at 89.

[570] Gorman Direct Testimony at 94-97.

not reflect a reasonable risk proxy for the companies and are based on flawed applications of the market-based models.[571]

Walmart also provided expert witness testimony regarding the ROE, although Walmart did not provide an ROE recommendation based on an ROE model. Walmart argued that LG&E/KU's proposed ROE is excessive, especially in light of the use of risk-reducing rate-making structures such as a forecasted test year, the customer impact of the resulting revenue requirement increase, and recent ROEs approved in Kentucky and other jurisdictions nationwide.[572] Walmart provided an analysis which calculated the average authorized ROE for vertically integrated utilities from 2023 through present[573] as 9.77 percent, which it stated it provided to illustrate a national customer's perspective on industry trends in authorized ROE.[574] Walmart recommended that, unless the Commission determines that a higher ROE is warranted due to changes in circumstances since LG&E/KU's last rate case, it should approve an ROE no higher than LG&E/KU's currently authorized ROE of 9.425 percent.[575]

Additionally, Joint Intervenors recommended, should certain proposed performance metrics not be achieved, penalties of (1) a dollar amount equivalent to a 15 basis point reduction to LG&E/KU's ROE for noncompliance with a single improvement

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[571] Gorman Direct Testimony at 98-99.

[572] Direct Testimony of Lisa V. Perry (Perry Direct Testimony) (filed Aug. 29, 2025) at 9.

[573] The Commission notes that the Perry Direct Testimony, Exhibit LVP-3, which contains the data used in this analysis, references the source of the data as S&P Global Market Intelligence and stated that the source was last updated on July 24, 2025. Therefore, the Commission reads the term "present" to be as of the last update to the data provided in the analysis, July 24, 2025.

[574] Perry Direct Testimony at 12-15.

[575] Perry Direct Testimony at 16.

goal and (2) a dollar amount equivalent to a 25 basis point reduction to LG&E/KU's ROE for noncompliance with multiple improvements goals.[576] However, Joint Intervenors explained that their recommended sanctions would not result in a change to LG&E/KU's authorized ROE, but would be calculated to produce a revenue reduction equivalent to the specified ROE reduction, which they recommended would then be deferred as a regulatory liability which would be refunded to customers in LG&E/KU's next base rate case.[577]

In rebuttal, due to the passage of time since their original analysis, LG&E/KU updated their analysis, which resulted in unadjusted reasonable ranges of 10.41 percent to 11.05 percent for LG&E's natural gas operations and 10.13 percent to 10.89 percent for LG&E and KU's electric operations, as well as adjusted reasonable ranges of 10.71 percent to 11.35 percent, 10.31 percent to 11.07 percent, and 10.26 percent to 11.02 percent for LG&E's natural gas operations, LG&E's electric operations and KU's electric operations, respectively.[578] However, LG&E/KU argued that, based on the updated results, their initial ROE recommendation of 10.95 percent remains reasonable.[579] LG&E/KU agreed with the Attorney General/KIUC's position that allowed ROEs should not be a substitute for market analyses.[580] LG&E/KU argued that, while authorized ROEs may be reasonable benchmarks of acceptable ROEs, care must be exercised when evaluating their applicability in any given case due to historical authorized

[576] Direct Testimony of Roger D. Colton (Colton Direct Testimony) (filed Aug. 29, 2025) at 100.

[577] Colton Direct Testimony at 100.

[578] Rebuttal Testimony of Dylan W. D'Ascendis (D'Ascendis Rebuttal Testimony) at 2.

[579] D'Ascendis Rebuttal Testimony at 2.

[580] D'Ascendis Rebuttal Testimony at 8.

returns not reflecting the investor-required return because authorized ROEs are a lagging indicator of investor-required returns and the economic conditions in the past are not representative of economic conditions now.[581] LG&E/KU disagreed with the Attorney General/KIUC's assessment of capital market conditions, and argued that the Attorney General/KIUC's analyses do not fully reflect increasing interest rates since LG&E/KU's most recent rate case in their recommendation.[582] LG&E/KU also disagreed with specific assumptions and inputs to the Attorney General/KIUC's application of the CAPM, specifically the calculation of forward-looking and supply-side market risk premium, the time-adjusted historical market risk premium and consideration of other market risk premiums in the CAPM, and the lack of an ECAPM analysis.[583] Additionally, LG&E/KU disagreed with the AG/KIUC's use of dividend per share growth rates, substitution of certain proxy earnings per share growth rates, and the use of outdated dividend data in the DCF model.[584] Finally, LG&E/KU disagreed with the Attorney General/KIUC's decision to not reflect any company-specific risks in their recommendations.[585]

LG&E/KU disagreed with the DOD/FEA's contention that utilities have maintained their credit quality in recent years, and argued that there is significant downward movement in utility credit ratings and that that shift toward lower credit ratings indicates a deteriorating credit environment for the utility industry which increases overall investment

[581] D'Ascendis Rebuttal Testimony at 8.

[582] D'Ascendis Rebuttal Testimony at 12-15.

[583] D'Ascendis Rebuttal Testimony at 23.

[584] D'Ascendis Rebuttal Testimony at 16.

[585] D'Ascendis Rebuttal Testimony at 39-41.

risk.[586] With regard to the DOD/FEA's DCF model, LG&E/KU argued that the sustainable growth model is inconsistent with both academic and empirical findings, and that it is inappropriate to rely on the multi-stage DCF model given that utilities are in the steady state growth stage.[587] LG&E/KU stated they had concerns with the DOD/FEA's application of the RPM, specifically the time period used, ignoring that there is an inverse relationship between equity risk premiums and interest rates, the mismatched application of projected Treasury bond yields and current utility bond yields, and the DOD/FEA's downward adjustment to the equity risk premium.[588] LG&E/KU stated that they generally agree with the inputs in the DOD/FEA's CAPM; however, they do not agree with the DOD/FEA's exclusion of an ECAPM analysis.[589] LG&E/KU critiqued the DOD/FEA's lack of consideration of size and flotation cost adjustments, and argued that LG&E/KU's operations in Kentucky should be considered stand-alone companies as the return derived in this proceeding will not apply to PPL's operations, but only LG&E/KU's operations in Kentucky, as well as that denying recovery of issuance costs would penalize the investors that fund the utility operations.[590] LG&E/KU disagreed with the DOD/FEA's contention that ROE for LG&E's natural gas operations should be adjusted downward to reflect a lower level of financial risk.[591] However, LG&E/KU maintained their downward adjustments to their recommended ROE for LG&E/KU's electric operations due to their

[586] D'Ascendis Rebuttal Testimony at 57.

[587] D'Ascendis Rebuttal Testimony at 67.

[588] D'Ascendis Rebuttal Testimony at 68.

[589] D'Ascendis Rebuttal Testimony at 77.

[590] D'Ascendis Rebuttal Testimony at 80-81.

[591] D'Ascendis Rebuttal Testimony at 83.

lower level of financial risk.[592] Finally, LG&E/KU disagreed with the premise of the DOD/FEA's analysis and conclusions regarding their assessment of their recommendation as it affects measures of LG&E/KU's financial integrity, and argued that simply maintaining an investment grade rating is an inappropriate standard and that, because LG&E/KU must compete for capital with both affiliated companies, other utilities, and non-utilities, LG&E/KU must have a strong financial profile which enables LG&E/KU to acquire capital even during constrained and uncertain markets.[593] In response to Walmart's testimony and analysis, LG&E/KU reiterated its position that authorized ROEs do not reflect the current ROE, and that care must be taken when considering their applicability to the current forward-looking ROE to be set in this proceeding.[594]

The Signing Parties agreed that an ROE of 9.90 percent is reasonable for LG&E/KU's electric and gas operations,[595] and the agreed stipulated revenue requirement increases for LG&E/KU's operations reflect that return on equity as applied to LG&E/KU's capitalizations and capital structures.[596] The use of a 9.90 percent ROE would reduce LG&E/KU's adjusted proposed electric and gas revenue requirement increases by $45.9 million for KU and $27.8 million for LG&E electric operations,[597] and by $10.5 million for LG&E gas operations.[598] The Stipulation also stated that the agreed-

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[592] D'Ascendis Rebuttal Testimony at 83.

[593] D'Ascendis Rebuttal Testimony at 83-85.

[594] D'Ascendis Rebuttal Testimony at 92-93.

[595] *See* Stipulation Testimony at 19, where LG&E/KU stated that the explanation for the ROE adjustment is the same for both electric and gas operations; Stipulation, Section 2.2(a).

[596] Stipulation Testimony at 13.

[597] Stipulation Testimony at 13.

[598] Stipulation Testimony at 19.

upon 9.90 percent ROE would apply to recovery under all mechanisms.[599] The following table presents the recommended ROEs from LG&E/KU and the Intervenors and the methods used to support each parties' recommendations:

Party	Recommendation	Methods
LG&E/KU	10.95%	DCF, CAPM, ECAPM, RPM, PRPM
Attorney General/KIUC	9.60%	DCF, CAPM
DOD/FEA	9.50%	DCF, CAPM, RPM
Walmart	No Higher Than 9.425%	Survey of Awarded ROEs
Joint Stipulation		
Base Rates	9.90%	
Capital Riders	9.90%	

For the reasons discussed below, the Commission finds that an ROE of 9.90 percent for LG&E/KU's electric and gas operations is unreasonable and higher than that required by investors in today's economic climate, and this provision of the Stipulation should be modified. Additionally, as further discussed below, the Commission finds that an ROE of 9.90 percent is unreasonable for application to recovery of LG&E/KU's Retired Asset Recovery Adjustment Clause, ECR Surcharge Adjustment Clause, and GCR, as well as the GLT specific to LG&E, and this provision of the Stipulation should also be modified.

In evaluating the ROE for LG&E/KU, the Commission must evaluate and review evidence in the record and balance the financial integrity of the utility with the interest of the consumer and the statutory obligation that rates be fair, just and reasonable. As

[599] Stipulation Testimony at 13.

demonstrated in the respective ROE testimonies in this proceeding, there is considerable variation in both data and application within each modeling approach, which can lead to differing results. In recent cases, such as Case No. 2024-00354[600] and Case No. 2025-00122,[601] the Commission explained why it is appropriate for utilities to present, and for the Commission to evaluate, multiple methodologies to estimate ROEs, as each approach has its own strengths and limiting assumptions.

The Commission agrees with the Attorney General/KIUC and DOD/FEA's arguments discussed above that the LG&E/KU has not proven that the PRPM is relied upon by investors to determine their required ROE for regulated electric and gas utilities, and the results of the PRPM should be disregarded. The Commission has rejected the use of the PRPM in the consideration of a reasonable ROE in past cases[602] and continues to reject the use of the PRPM in this proceeding.

The Commission reiterates it continues to reject the use of flotation cost adjustments, size adjustments, and credit risk adjustments, and the use of non-regulated proxy groups. The Commission agrees with the Attorney General/KIUC's argument that stock prices most likely already account for flotation costs, to the extent that such costs

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[600] Case No. 2024-00354, *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 Oct. 2, 2025), Order at 50-51.

[601] Case No. 2025-00122, *Electronic Application of Kentucky-American Water Company for An Adjustment of Rates* (Ky. PSC Dec. 16, 2025), Order at 62-63.

[602] See Case No. 2024-00092, *Electronic Application of Columbia Gas of Kentucky, Inc. For An Adjustment of Rates; Approval of Depreciation Study; Approval of Tariff Revisions; And Other Relief* (Ky. PSC Dec. 30, 2024), Order at 43; Case No. 2024-00276, Aug. 11, 2025, Order at 36; and Case No. 2024-00354, Oct. 2, 2025, Order at 51, in which the Commission rejected the use of the PRPM in the ROE analysis.

are even considered by investors.[603] The Commission evaluates all models but affords the most weight to DCF and CAPM analyses based upon regulated company proxy groups. Both the DCF and CAPM are long-standing, well accepted models, that evaluate risk and returns both implicitly and explicitly.

Additionally, the Commission continues to caution all parties against unreasonably removing or ignoring "outlier" data due to a subjective perception of being "too high" or "too low." Multiple actions can be taken into account for "outlier" or "unreasonable" data. Result-oriented exclusions of data that are not beyond the realm of reasonableness are inappropriate.

The Commission is not persuaded by LG&E/KU's argument that a 9.90 percent Stipulated ROE is reasonable. The Commission agrees that the stipulated stay-out commitment of over 2.5 years presents greater financial risk to LG&E/KU. However, as discussed below, the Commission is approving, with modifications, the proposed Generation Cost Recovery Rider (GCR) in this proceeding. This rider allows for contemporaneous recovery of the non-fuel costs associated with Mill Creek 5, the E.W. Brown BESS, Mercer County Solar, and Marion County Solar, with the Commission's addition of the stay-open costs associated with Mill Creek 2. As such, the Commission believes that the increased risk associated with the stay-out commitment is significantly diminished by the opportunity to recover such costs on a monthly basis throughout the parties' agreed upon time period before LG&E/KU can request a rate increase, and that any increased risk LG&E/KU is assuming for the volatility in the remaining costs it expects

[603] Baudino Direct Testimony at 63.

to incur over the next two and a half years does not warrant such an increase in its allowed return.

The Commission finds that the Stipulated 9.90 percent ROE overstates the risks that LG&E/KU faces and thus overstates the allowed return for investors. For the reasons set forth above, the Commission finds that an ROE of 9.775 percent is fair, just, and reasonable and appropriately balances the needs of LG&E/KU and its customers and addresses the current economic state of the capital market, and the risks noted above. Due to the lower risk associated with contemporaneous recovery, the Commission continues to view capital riders as providing lower risk to the utility and finds that a 10-basis point reduction in the ROE component of LG&E/KU's capital riders, including the GCR, from 9.775 percent to 9.675 percent is fair, just and reasonable.

Capital Structure/Cost of Debt

KU's proposed capital structure consists of 2.55 percent short-term debt, 44.60 percent long-term debt, and 52.86 percent common equity.[604] KU stated that its cost of debt reflects the interest rate payable on KU's short-term and long-term debt and is determined by calculating the weighted average interest rate of KU's existing long-term debt outstanding, including the amortized fees, and short-term debt is comprised of the cost of commercial paper, term or bank loans, and affiliate borrowings.[605] KU's weighted average cost of long-term and short-term debt was forecasted to be 4.93 percent and 4.46 percent, respectively, for the test year.[606] KU argued that its cost of debt is

[604] D'Ascendis Direct Testimony at 16.

[605] Direct Testimony of Julissa Burgos (Burgos Direct Testimony) (filed May 30, 2025) at 2-3.

[606] Burgos Direct Testimony at 3.

reasonable, given the focus on achieving best execution at time of issuance and maintaining high credit quality.[607] In its application, KU stated that it anticipated issuing $800 million in long-term debt in August 2025 (August 2025 Issuance), to pay down debt maturities of $250 million and for general corporate purposes.[608] KU also stated that it did not expect to issue debt during the forecast test year.[609] KU's proposed capital structure and the costs assigned to each capital component are shown in the table below:[610]

Class of Capital	13-Month Average Amount	Jurisdictional Adjusted Capital	Percent of Total	Cost Rate	13-Month Average Weighted Cost
Short-Term Debt	$ 204,915,642	$ 157,536,900	2.55%	4.46%	0.11%
Long-Term Debt	3,588,812,215	2,759,039,499	44.60%	4.93%	2.20%
Common Equity	4,253,980,389	3,270,164,828	52.86%	10.95%	5.79%
Total Capital	$ 8,047,708,246	$ 6,186,741,227	100.00%		8.10%

On August 25, 2025, KU provided a revised capital structure, which is also reflected in the Base Period Update.[611] KU's revised capital structure consisted of 2.87 percent short-term debt, 44.33 percent long-term debt, and 52.80 percent common equity.[612] KU's proposed costs of short-term and long-term debt remained unchanged as

[607] Burgos Direct Testimony at 4.

[608] Burgos Direct Testimony at 9.

[609] Burgos Direct Testimony at 9; See Case No. 2023-00397, *Electronic Application of Kentucky Utilities Company for An Order Authorizing the Issuance of Indebtedness* (Ky. PSC Feb 8, 2024), Order.

[610] Application, Schedule J-1.1/J-1.2 at 1.

[611] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J-1.1/J-1.2; Base Period Update.

[612] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J-1.1/J-1.2.

a result of the August 25, 2025 Supplemental Filing. KU's revised forecasted capital structure and assigned cost rates are shown in the table below:[613]

Class of Capital	13-Month Average Amount	Jurisdictional Adjusted Capital	Percent of Total	Cost Rate	13-Month Average Weighted Cost
Short-Term Debt	$ 232,249,903	$ 177,461,240	2.87%	4.46%	0.13%
Long-Term Debt	3,588,812,215	2,742,197,338	44.33%	4.93%	2.19%
Common Equity	4,275,298,398	3,266,491,582	52.80%	10.95%	5.78%
Total Capital	$ 8,096,360,516	$ 6,186,150,159	100.00%		8.10%

The Attorney Generally/KIUC originally recommended the Commission accept KU's filed capital structure for ratemaking purposes, as well as KU's filed costs of short-term debt.[614] Additionally, the Attorney General/KIUC recommended KU's cost of long-term debt be adjusted downward to reflect the August 2025 Issuance.[615] The Attorney General/KIUC recommended the Commission adjust KU's assumed coupon rate of 6.50 percent, for the new long-term debt issuance of $800 million included in its proposed capital structure, to the actual coupon rate of 5.85 percent from the August 2025 Issuance of the long-term debt.[616] However, the Attorney General/KIUC recommended the Commission accept KU's proposed forecasted common equity percentage of 52.86 percent, and not adjust the capital structure due to the size of the August 2025

[613] August 25, 2025 Supplemental Filing, Item 54, Attachment, Schedule J-1.1/J-1.2.

[614] Baudino Direct Testimony at 3.

[615] Baudino Direct Testimony at 4.

[616] Baudino Direct Testimony at 39.

Issuance being $700 million rather than the projected $800 million, given the proposed common equity percentage is a forecasted amount for the test year.[617]

The DOD/FEA argued that KU's proposed ratemaking capital structures contain a higher percentage of common equity to total capital than the industry average and median capital structure that is approved for setting rates, which they calculated as approximately 50 to 52 percent for electric utilities over the last 10 years, compared to KU's proposed ratemaking capital structure containing 53 percent equity.[618] The DOD/FEA argued that KU's proposed ratemaking capital structure contains common equity ratios that are greater than necessary to support its financial integrity and credit standing.[619] The DOD/FEA did not recommend any adjustments to KU's proposed ratemaking capital structure.[620] However, the DOD/FEA argued that a capital structure too heavily weighted with common equity reflects too little financial risk and will increase the utility's overall rate of return with little to no benefit to retail customers, and stated that, consequently, they considered the higher cost to customers to lower KU's financial risk in recommending their authorized ROE.[621] Finally, the DOD/FEA used both KU's proposed cost of short-term debt and proposed cost of long term debt of 4.46 percent and 4.93 percent, respectively, in the development of their recommended overall rate of return.[622]

[617] Baudino Direct Testimony at 39-40.

[618] Gorman Direct Testimony at 24-25.

[619] Gorman Direct Testimony at 27.

[620] Gorman Direct Testimony at 3.

[621] Gorman Direct Testimony at 26-27.

[622] Gorman Direct Testimony at 27.

In rebuttal, KU agreed that it is reasonable to review the capital structures of the proxy companies; however, it argued that the range of common equity ratios for the Utility Proxy Groups and the operating utilities of the Utility Proxy Groups depict the range of typical or proper equity ratios maintained by comparable risk companies.[623]

In the Stipulation, the Signing Parties agreed to reduce the long-term debt rate from the debt rate in KU's initial application which included issuances with an assumed coupon rate of 6.50 percent, to reflect the actual coupon rate of the long-term debt KU issued in August 2025, of 5.85 percent.[624] This adjustment reduces KU's adjusted proposed electric revenue requirement increase by $4.4 million.[625]

The Commission finds that a capital structure consisting of 2.87 percent short-term debt, 44.33 percent long-term debt, and 52.80 percent common equity should be approved for KU for ratemaking purposes. Additionally, the Commission agrees that KU's cost of long-term debt should be revised to reflect the actual coupon rate of the long-term debt KU issued in the August 2025 Issuance. The Commission finds that the cost of short-term debt of 4.46 percent and cost of long-term debt of 4.76 percent should be approved for ratemaking purposes. The approved capital structure and costs of short-term and long-term debt approved for ratemaking purposes are consistent with the Stipulated capital structure and costs of debt without modification. The Commission, however, recognizes and shares intervenors' concern regarding the size of KU's common equity ratio. Utilities in Kentucky should have a capital structure that is appropriately and

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[623] D'Ascendis Rebuttal Testimony at 82.

[624] Stipulation Testimony at 15-16.

[625] Stipulation Testimony at 16.

reasonably balanced between debt and equity, as to not inflate the authorized weighted average cost of capital due to common equity being inherently more expensive than debt.[626] The Commission therefore cautions KU to exercise prudent control over the amount of equity that it issues so that it maintains a balanced capital structure.

Rate of Return Summary

Applying the cost rates of 4.46 percent for short-term debt, 4.76 percent or long-term debt, and 9.775 percent for common equity, the capital structure percentages consisting of 2.87 percent, 44.33 percent, and 52.80 percent, respectively, produce an overall weighted average cost of capital of 7.40 percent.

Capital Component	Percentage	Cost Rate	Weighted Cost
Long-Term Debt	44.33%	4.76%	2.11%
Short-Term Debt	2.87%	4.46%	0.13%
Common Equity	52.80%	9.775%	5.16%
Total	100.00%		7.40%

Total Revenue Requirement Summary

The effect of the Commission's adjustments is a total revenue requirement increase of approximately $ 128,483,032, as shown in Appendix C, which includes the authorized ROE discussed above. This reflects a $97,638,815 decrease in KU's originally requested revenue increase of $226,315,920.

[626] See Case No. 2022-00372, *Electronic Application of Duke Energy Kentucky, Inc. For (1) an Adjustment of 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 Oct. 12, 2023), Order at 35; Case No. 2023-00191, *Electronic Application of Kentucky-American Water Company For an Adjustment of Rates, A Certificate of Public Convenience and Necessity For Installation of Advanced Metering Infrastructure, Approval of Regulatory And Accounting Treatments, and Tariff Revisions* (Ky. PSC May 3, 2024), Order at 28.

Kentucky Utilities Company Requested Rate Increase	$	226,316,839
Kentucky Utilities Company Updated Adjustment		(6,203,086)
	$	220,113,753
Adjustments:		
O&M Adjustments:		
Incentive Compensation		(1,911,340)
401(k) Expense		(937,029)
Membership Dues		(533,443)
Depreciation Expense		(14,454,265)
Depreciation Error		(3,974,532)
Payroll Tax		(148,924)
Rate Case Expense		(133,611)
Rate Base Adjustments		(69,537,578)
Rate Increase	$	128,483,032
Percent Rate Increase		6.88%

*Differences are due to rounding

ADJUSTMENT CLAUSES

Renewable Power Purchase Agreement Adjustment Clause. KU requested approval of renewable power purchase agreements (RPPA) Adjustment Clause (Adjustment Clause RPPA) – a separate adjustment clause designed to recover the cost of solar power purchase agreements (PPAs) and other future renewable energy PPAs.[627] KU explained that Adjustment Clause RPPA would implement a per-kWh charge to recover the cost of approved PPAs each month net of (1) any net revenues from sales of environmental attributes (currently expected to be renewable energy certificates) and (2) a balancing

[627] Application at 14.

adjustment for previous over- or under-collections.[628] Similar to KU's other cost-recovery mechanisms, under Adjustment Clause RPPA, KU would bill the net expenses from one month in the second month following the first month's billing cycle (e.g., the expense month of May would be billed during the July billing cycle).[629] KU stated that it would file the Adjustment Clause RPPA rate with the Commission ten days before it is scheduled to go into effect, along with all the necessary supporting data to justify the factor, including any data and information the Commission requires.[630]

KU also proposed a sample schedule for the monthly filings.[631] For example, for Expense Month of March 2026, the filing date with the Commission would be April 20, 2026.[632]

KU explained that to date, LG&E/KU have entered into six total PPAs.[633] KU stated that three of the PPAs have been terminated and the other three appear unlikely to proceed on their original terms, and KU proposed a separate adjustment clause to recover the cost of such PPAs and other future renewable energy PPAs later approved by the Commission.[634] KU stated that the Commission declined to address cost recovery

[628] Application at 14-15.

[629] Application at 14-15.

[630] Fackler Direct Testimony at 37.

[631] KU's Response to Staff's Post-Hearing Request, Item 22a.

[632] KU's Response to Staff's Post-Hearing Request, Item 22a.

[633] Fackler Direct Testimony at 36. KU and LG&E entered into the agreements jointly.

[634] Fackler Direct Testimony at 36.

for such PPAs as premature in LG&E/KU's 2022 CPCN proceeding[635] in which the Commission approved four of the six total PPAs.[636]

The Attorney General/KIUC originally recommended that the Commission deny KU's request for Adjustment Clause RPPA as premature.[637] The Attorney General/KIUC argued that, if the Commission proceeds to substantively address LG&E/KU's request, then the Attorney General/KIUC recommend it deny KU's proposed recovery of the purchased power expense on a per kWh basis and instead adopt an allocation methodology that reflects the fact the RPPA costs are inherently fixed costs, regardless of whether the purchases are denominated on a kWh basis.[638]

KU rebutted that, although no RPPA is immediately poised to advance to completion, does not make it "premature" to address the appropriate cost recovery mechanism in these proceedings.[639] KU stated not addressing Adjustment Clause RPPA in these proceedings would be administratively inefficient, potentially requiring additional proceedings before the Commission that could be avoided by addressing the proposal now.[640] KU also stated that, from a timing perspective, considering and deciding upon Adjustment Clause RPPA in these proceedings would be consistent with the Commission's consideration and approval of the Retirement Asset Recovery (RAR) Rider

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[635] Case No. 2022-00402, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements,* (Ky. PSC Nov. 6, 2023).

[636] Fackler Direct Testimony at 36.

[637] Kollen Corrected Direct Testimony at 8-9.

[638] Kollen Corrected Direct Testimony at 9.

[639] Fackler Rebuttal Testimony at 7.

[640] Fackler Rebuttal Testimony at 8.

first proposed in agreed recommendations—which the AG and KIUC signed and supported—in Case Nos. 2020-00349.[641] KU also stated that it does not oppose revising Adjustment Clause RPPA to implement this methodology, if the Commission believes it is appropriate to do so.[642]

The Adjustment Clause RPPA, while not explicitly mentioned in the Stipulation, was agreed to as filed through the catch all provision.[643]

Having considered the record, and being otherwise sufficiently advised, the Commission finds that the Adjustment Clause RPPA should be denied. The Commission finds compelling the Attorney General/KIUC's pre-Stipulation position that the request for the RPPA is premature. As three of LG&E/KU's PPAs have been terminated and the other three appear unlikely to proceed on their original terms, the Commission does not find that there is substantial evidence to support the approval of this mechanism. Even if the three PPAs move forward, the costs associated with the PPAs are unknown at this time, and therefore the potential impacts to ratepayers is unknown.

Mill Creek 2 and Mill Creek 6 Adjustment Clauses. KU filed supplemental testimony supporting the Mill Creek 2 Adjustment Clause (Adjustment Clause MC2). Prior to the Stipulation, the Attorney General/KIUC filed testimony regarding Adjustment Clause MC2 as well as the Mill Creek 6 Adjustment Clause (Adjustment Clause MC6) in this docket.[644] These adjustment clauses only apply to LG&E because LG&E owns 100 percent of Mill

[641] Fackler Rebuttal Testimony at 9.

[642] Fackler Rebuttal Testimony at 10-11.

[643] Amended Stipulation, Section 11.1.

[644] Kollen Corrected Direct Testimony at 96–97.

Creek 2 and plans to own 100 percent of Mill Creek 6. Therefore, the Commission does not make any findings regarding those clauses in this case.

Generation Cost Recovery Adjustment Clause (Adjustment Clause GCR/ Pilot Generation Recovery (Adjustment Clause PGR). As set forth in the Stipulation, Adjustment Clause GCR is a proposed, new tariff mechanism that will permanently recover all non-fuel costs of generation assets and any incremental capital additions for the life of included assets.[645]

In the Stipulation, the Signing Parties agreed to the Adjustment Clause GCR. The Stipulation further included agreement for all new generation and energy storage assets approved by the Commission, but not yet in service as of the date of the final Order in these proceedings, including Mill Creek 5, the E.W. Brown Battery Energy Storage System (Brown BESS), Mercer County Solar, Marion County Solar, and Brown 12 be included in the Adjustment Clause GCR.[646] Adjustment Clause GCR would be materially identical in form and function to the proposed Adjustment Clause MC6 from Case No. 2025-00045, except Adjustment Clause GCR will not have an Offsetting Revenues component.[647] Adjustment Clause GCR would collect capital and non-fuel operating costs from customers over the life of included units on a percentage of revenue basis, allocated in the same way as KU's current environmental cost recovery mechanism.

The Signing Parties to the Stipulation proposed that KU would file its proposed GCR cost recovery factors with the Commission in the month before it bills the factor, with

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[645] Stipulation at 12.

[646] Stipulation at 12. The proposed Adjustment Clause GCR excludes Mill Creek 6.

[647] Joint Stipulation Testimony of Robert Conroy and Christopher Garrett (Stipulation Testimony) (filed Oct. 20, 2025) at 7.

expenses based on the previous month (e.g., January expenses will appear in the February report and be billed in March). The Stipulation also recommended annual review proceedings for the Commission to review costs recovered under Adjustment Clause GCR,[648] KU argued these focused annual review proceedings, as well as monthly GCR filings, would provide the Commission frequent review opportunities and ensure all costs KU recover are prudent and reasonable, which benefits ratepayers.[649]

KU provided supplemental testimony addressing Adjustment Clause GCR, included was the expected bill impact of the Adjustment Clause GCR.[650] According to KU, in 2027, Adjustment Clause GCR would recover approximately $64.2 million in revenues and be expected to increase residential customers' bills by 3.10 percent.[651] For years 2028, 2029, 2030, 2031, and 2032, the adjustment clause would recover approximately $111.0 million, $109.1 million, $105.2 million, $105.0 million, and $99.6 million and increase residential customers' bills by 5.36 percent, 5.27 percent, 5.08 percent, 5.08 percent, and 4.81 percent, respectively.[652] KU also stated that, because of the declining rate base, customers will benefit from a lower return between rate cases.[653] KU stated that the potential savings are over $100 million in present value

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[648] Stipulation Testimony at 7.

[649] Joint Supplemental Testimony of Robert Conroy and Chistopher Garrett (Supplemental Testimony) (filed Oct. 31, 2025) at 7.

[650] Supplemental Stipulation Testimony at 5.

[651] Supplemental Stipulation Testimony, Exhibit 1.

[652] Supplemental Stipulation Testimony, Exhibit 1 and KU's Response to Staff's Post-Hearing Request, Item 4.

[653] Supplemental Stipulation Testimony at 6.

savings through the life of the assets for LG&E/KU, assuming rate cases are filed every three years.[654]

Joint Intervenors argued that Adjustment Clause GCR should be rejected.[655] Joint Intervenors argued that the adjustment clause was not properly before the Commission, non-Signing Parties to the Stipulation were not afforded the opportunity to file testimony regarding this mechanism, and public notice was not given for the mechanism.[656] Joint Intervenors also argued that KU failed to provide any evidence that the mechanism is necessary to support KU's financial health.[657] Finally, Joint Intervenors opined that Adjustment Clause GCR's review schedule would create administrative overload, not lead to the meaningful review of costs, and that the recovery of these assets are better determined in a rate case.[658]

The Commission does not find that the Joint Intervenors' argument that Adjustment Clause GCR is not properly before the Commission compelling. The Attorney General/KIUC presented testimony related to an adjustment clause for Mill Creek 2 and Mill Creek 6. The Adjustment Clause GCR is a substantially similar version of that clause, just expanded to include other generating units. In Case No. 2025-00045, the Commission encouraged KU to provide more evidence in support of the Mill Creek 2 and 6 mechanisms, in a separate proceeding.[659] The Commission believes that KU has

[654] Supplemental Stipulation Testimony at 7.

[655] Joint Intervenors' Post Hearing Brief at 90.

[656] Joint Intervenors' Post Hearing Brief at 90–95.

[657] Joint Intervenors' Post Hearing Brief at 98–99.

[658] Joint Intervenors' Post Hearing Brief at 99–102.

[659] Case No. 2025-00045, Oct. 28, 2025 Order at 154.

provided substantial evidence of the Adjustment Clause GCR in this proceeding as to warrant its approval with modifications.

The Commission finds that the Adjustment Clause GCR component of the Stipulation should be approved with modifications discussed further below. The Commission will change the name to differentiate the GCR from the gas cost recovery rider acronym. The new name will be the Pilot Generation Recovery Adjustment Clause (PGR).[660] As KU and LG&E are separate entities, the Adjustment Clause PGR rates and filings should be filed separately for each utility.

The Commission approves this adjustment clause on a pilot basis, rather than for the full life of the assets, and finds that KU should present evidence of the actual bill impacts with its next rate case. The Commission is concerned about the potentially large bill impacts of the adjustment clause but does see the value in capturing the decline in rate base between rate cases due to depreciation. The potential savings are substantial at over $100 million in present value savings. While the adjustment clause is not strictly necessary to maintain KU's financial health, it could make it easier for KU to stay out longer before filing another rate case. This is because large generation assets will go into service in the 2027–2028-time frame; consequently, it is reasonably possible to expect customer benefits in lower administrative costs and postponed inflation of operating expenses, if the mechanism operates as presented by KU in this case. The volatility in planning future generation assets will not go away in the near term. Approving this adjustment clause on a pilot basis will allow the Commission to consider how the mechanism functions and whether a full review of the relevant costs can be achieved

[660] Note that from here on, the GCR will now be referred to as PGR.

outside of a rate adjustment application. The pilot version of this adjustment clause will terminate ten months after the filed date of the next base rate case, or the effective date of new rates, whichever is first. The stay-out provision of the Stipulation runs through August 1, 2028.[661] As Brown 12 is expected to be in service in 2030[662], Brown 12 should be excluded from the PGR, because it will not be in service before the expiration of the stay out provision in the proposed Stipulation and the costs are more uncertain than the other generation units. KU may request the inclusion of Brown 12 separately from a base rate case because no incremental expenses are included in the test year. Additionally, Brown BESS is 100 percent owned by LG&E and thus, should also be excluded from the KU PGR. As a post-case filing, KU should file the final ownership percentage when each unit included in the PGR goes into service. KU's PGR tariff should specify that the percentage of costs running through KU's adjustment clause for each generating unit is based on the final ownership percentage.

The Commission finds that all costs recovered through Adjustment Clause PGR should be separately identified in the next base rate case. Those costs could be kept separate in perpetuity, or the Commission could have KU incorporate existing rider costs into base rates in a subsequent rate case. The Commission will weigh all options in the next base rate case where the impacts can be holistically determined. To limit the potential rate impacts and to encourage KU to control construction costs, construction

[661] Stipulation at 3. *See also* Stipulation Testimony at 6. KU stated that it would be required to file a rate case during the stay-out period absent the Stipulation. Therefore, whether the stay-out provision is realized, Brown 12 is unlikely to be in service before KU's next rate case.

[662] Case No. 2025-00045, Oct. 28, 2025 Order at 10.

costs for the pilot period should be limited to the estimations provided in Case No. 2022-00402[663] and 2025-00045.[664]

The Commission also finds that the Adjustment Clause PGR tariff should better specify the property tax calculations, should utilize the lead/lag study to calculate the CWC component, and that a lower ROE should be authorized. The Stipulation is silent on how property tax is determined after the first year and whether that approach aligns with how other utility assets are assessed for property tax. KU should specify in its tariff whether it will use CWIP for all years before generation assets are placed in service, whether CWIP for other assets factors into property tax determinations, and the methodology KU intends to utilize after the units go into service. However, KU's inclusion of its intended methodology should not be considered Commission approval of that proposed system prior to a formal proceeding investigating the matter. The Signing Parties proposed to use the 1/8 method to calculate the CWC component of rate case for Adjustment Clause PGR.[665] The 1/8 method is less accurate than the lead/lag study, and when there is a lead/lag study available the Commission generally prefers the use of the lead/lag study. Therefore, the Commission finds that rather than using the 1/8 method, KU should use the lead/lag study KU conducted in this case. As discussed in the section entitled Return on Equity (ROE), a lower ROE in the amount of 9.675 percent should be

[663] Case No. 2022-00402, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements* (Ky. PSC Nov. 6, 2023).

[664] Case No. 2025-00045, Oct. 28, 2025 Order.

[665] Supplemental Stipulation Testimony, Exhibit 2, Form 2.20.

approved for this rider, consistent with previous findings that capital riders reduce the risk to the utility.

Sharing Mechanism Adjustment Clause. KU stated that the Signing Parties to the Stipulation agreed to a time-limited Sharing Mechanism (Adjustment Clause SM) that will be in effect for just thirteen months (from and including July 1, 2027 through and including July 31, 2028) to account for any base rate revenue deficiency or surplus during that portion of the base-rate stay-out relative to an ROE deadband of 9.40 percent to 10.15 percent.[666] KU explained that it would make a true-up filing on February 1, 2030.[667] The true-up would account only for any over- or under- collection or distribution from or to customers of the revenue deficiency or surplus that Adjustment Clause SM was supposed to have achieved during the Adjustment Period.

For example, KU explained if one of the utilities had a surplus of $10 million during the 13-month Reporting Period (July 2027 – July 2028), Adjustment Clause SM would attempt to distribute exactly $10 million to customers during the 13-month Adjustment Period (November 2028 – November 2029).[668] If actual distributions under Adjustment Clause SM were $9 million during the Adjustment Period, the true-up would distribute the remaining $1 million to customers.[669] The true-up adjustment would appear on

[666] Stipulation at 14.

[667] Stipulation Testimony at 10.

[668] Supplemental Stipulation Testimony at 10–11.

[669] Supplemental Stipulation Testimony at 11.

customers' bills during the March 2030 billing cycle.[670] KU would make only one true-up filing, and Adjustment Clause SM would then terminate.[671]

After the Reporting Period, KU proposed it would make a filing with the Commission by October 1, 2028, showing KU's calculations of its actual adjusted earned returns, the adjusted returns for the top and bottom end of the ROE deadband of 9.40 percent and 10.15 percent, and the resulting revenue deficiency or surplus (if any).[672] If there is a revenue deficiency or surplus, the amount will be collected from or distributed to customers during the November 2028 through November 2029 billing cycles (Adjustment Period). After the Adjustment Period, KU would make a one-time true-up filing on February 1, 2030, to account for any over- or under-collection from or distribution to customers during the Adjustment Period.[673] This over- or under- amount would be collected from or distributed to customers during the March 2030 billing cycle.[674]

Joint Intervenors argued that Adjustment Clause SM should be denied. Similar to arguments regarding Adjustment Clause GCR and Adjustment Clause MC2, Joint Intervenor's argued that Adjustment Clause SM is not properly before the Commission.[675] Joint Intervenors argued that Adjustment Clause SM unreasonably guarantees an ROE of 9.4 percent and is not necessary to support the financial health of KU.[676]

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[670] Supplemental Stipulation Testimony at 11.

[671] Supplemental Stipulation Testimony at 11.

[672] Supplemental Stipulation Testimony at 10–11.

[673] Supplemental Stipulation Testimony at 11.

[674] Stipulation, Section 7.5.

[675] Joint Intervenors' Post Hearing Brief at 103–104.

[676] Joint Intervenors' Post Hearing Brief at 105.

The Commission finds that the Adjustment Clause SM proposed in the Stipulation should be denied for the following reasons discussed below.

The Commission believes there is not sufficient information for a known and reasonable amount of revenue likely to be recovered from customers during the sharing mechanism period. As the recovery begins in 2028, along with Adjustment Clause PGR recovery beginning in the 2027–2028-time frame, customers would have the potential for large bill increases during this period. This Commission is especially concerned given that large bill increases may occur without customer notice.

Also, the Commission does not see the value in authorizing Adjustment Clause SM as opposed to a full rate case, when the Commission will have to review essentially the same information to determine the Adjustment Clause SM rates. Perhaps more importantly, a full rate case allows for customers to receive notice on the proposed increases, interested parties to intervene, and, at a minimum, customers to provide public comment.

KU stated that the filing made with the Commission by October 1, 2028, will include the following calculations: (1) the actual adjusted jurisdictional net operating income and earned return on common equity for each utility for the Reporting Period; (2) the adjusted jurisdictional net operating income necessary to achieve the return on common equity at the top and bottom of the return in equity deadband; and (3) the amount, if any, by which the actual adjusted net operating income exceeds the adjusted net operating income for the top end of the return on equity deadband (surplus) or falls short of the adjusted net operating income for the bottom end of the return on equity deadband (deficiency).[677]

[677] Stipulation, Article 7.5A.

The forms were designed, in part, using the base rate case filing requirement Schedules A, C, H, and J7 since the underlying calculations for Adjustment Clause SM will primarily mimic these schedules filed in the application in this proceeding.

KU's reported earned ROE from 2020 to 2024 ranged from 8.83 percent to 9.7 percent and from November 2024 through October 2025 was 10.18 percent.[678] As noted above, in the period when recovery begins for Adjustment Clause SM, large capital projects will also be under construction or in service, which has the potential to lower KU's earned ROE.

The Commission believes there is significant potential for cost shifting. In 2003, a Focused Management Audit of KU's Earnings Sharing Mechanism (ESM) was conducted.[679] One of the potential concerns highlighted by the auditor, which continues to be a concern here, was as follows:

> The ESM requires an annual filing based on actual booked revenues and expenses, and ESM rate adjustments are required when the results do not fall within the dead band dollar limits. Under certain circumstances, this structure invites cost shifting between filing years in order to maximize returns. For example, if a utility expected to have three years of performance just above the lower dead-band limit, it would be advantageous to shift costs into one year in order to decrease return below the dead band level in that year and invoke an ESM factor adjustment.[680]

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[678] KU's Response to DOD's First Request, Item 8 and KU's Response to Staff's Post-Hearing Request, Item 6.

[679] *Focused Management Audit of Louisville Gas and Electric's and Kentucky Utilities' Earnings Sharing Mechanism* (filed Aug. 31, 2003), Final Report: https://psc.ky.gov/agencies/psc/hot_list/m_audit/ku_lge/083103_LGE_final_rpt.pdf.

[680] *Focused Management Audit of Louisville Gas and Electric's and Kentucky Utilities' Earnings Sharing Mechanism,* Final Report at 25.

For the reasons set forth above, the Commission finds that Adjustment Clause SM is denied.

Off-System Sales Adjustment Clause. KU forecasted total off-system sales (OSS) margins of 3.487 million in the test year.[681] The Attorney General/KIUC explained that the OSS margins are reflected in the Adjustment Clause OSS with a sharing of 75 percent to customers and 25 percent to KU pursuant to the Commission Orders in Case No. 2014-00371.[682] The Attorney General/KIUC explained that, prior to the Commission Orders in those cases, the OSS margins were reflected in the base revenue requirement with a sharing of 100 percent to customers and 0 percent to the companies.[683]

Prior to the Stipulation, the Attorney General/KIUC recommended an increase in the allocation percentage in the Adjustment Clause OSS to customers to 100 percent from the present 75 percent.[684] The Attorney General/KIUC argued that the present allocation to customers of 75 percent were the result of settlements in prior base rate proceedings and are not justified or reasonable when considered on a standalone basis outside the compromises reflected in those settlements.[685] The Attorney General/KIUC argued there is no evidence that the present allocation to the Companies has incentivized them to make off-system sales that it otherwise could not or would not have made in the

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[681] KU's Response to the Attorney General/KIUC's First Request, Item 73.

[682] Kollen Corrected Direct Testimony at 91 citing Case No. 2014-00371, *Application of Kentucky Utilities Company for an Adjustment of Rates* and Case No. 2014-00272, *Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates*.

[683] Kollen Corrected Direct Testimony at 91.

[684] Kollen Corrected Direct Testimony at 92.

[685] Kollen Corrected Direct Testimony at 92.

normal course of business.[686] The Attorney General/KIUC highlighted that both KU and LG&E are constructing new generation capacity that likely will provide additional energy for off-system sales and increased OSS margins, at least temporarily.[687]

In its rebuttal testimony, KU argued there are no changed circumstances that justify re-trading the 2014 rate case settlement agreement the AG and KIUC signed, just as there is no justification for the Attorney General/KIUC's expert to change the 90 percent-10 percent sharing position—with customer downside risk—that they advocated in KU's 2014 base rate case.[688]

The Stipulation did not recommend the Attorney General/KIUC's proposal to change the OSS margins.

Having considered the record and being otherwise sufficiently advised, the Commission finds that continuing the OSS sharing of 75 percent customers and 25 percent to KU is reasonable. The Commission agrees with KU that there are no major changed circumstances that justify a change. Likewise, the Commission believes that, as 25 percent of the sales go to KU, this will incentivize KU to make sales that benefit both customers and itself.

COST OF SERVICE STUDY

In the development of the proposed rates, KU relied on its filed cost-of-service study (COSS) as a guide for its revenue allocation and rate design. For its COSS, KU

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[686] Kollen Corrected Direct Testimony at 92.

[687] Kollen Corrected Direct Testimony at 93.

[688] Conroy Rebuttal Testimony at 6.

applied the 6-Coincident Peak (6-CP) methodology for production fixed costs.[689] Additionally, KU filed a 12-Coincident Peak (12-CP) COSS. The 6-CP methodology is based on each rate class's share of monthly Coincident Peak demands during the three summer peak months of July through September and three winter peak months of December through February.[690] The allocator reflects that production fixed costs are incurred to meet customer demand requirements during the three summer and three winter months.[691] The class's average 6-CP is divided by the overall system's average 6-CP to get a percentage of allocation for each class. The percentage is applied to the total fixed production revenue requirement to determine how much of that cost that specific class is responsible for.

KU stated that energy costs were allocated based on kWh sales, adjusted to reflect losses.[692] The allocator is based on each rate class's share of annual kWh sales, adjusted to reflect losses.[693] KU stated that transmission plant was allocated based on peak demands, and utilized the 6-CP method.[694] The allocator is based on each rate class's share of system peak demand.[695] KU stated that distribution plant was allocated based on number of customers and peak demand.[696] The allocator is based,

[689] Direct Testimony of Timothy S. Lyons (Lyons Direct Testimony) (filed May 30, 2025) at 19.

[690] Lyons Direct Testimony at 19.

[691] Lyons Direct Testimony at 19.

[692] Lyons Direct Testimony at 20.

[693] Lyons Direct Testimony at 20.

[694] Lyons Direct Testimony at 20; KU's Response to Staff's Second Request, Item 35.

[695] Lyons Direct Testimony at 20.

[696] Lyons Direct Testimony at 20.

respectively, on each rate class's share of customers and each rate class's share of non-coincident peak (NCP) demands.[697]

KU explained that there were two special studies to allocate meter and service investments.[698] Meter investments were allocated based on the current cost of meters in each rate class.[699] The allocator reflected an estimated cost of meter and meter installation for each rate class.[700] Service investments were allocated based on the current cost of services in each rate class.[701] The allocator reflects an estimated cost of service line and installation for each customer class.[702]

KU explained that O&M expenses were allocated to each rate class consistent with their respective associated plant accounts.[703] Finally, KU noted that there are several composite allocators developed internally based on the allocation of various plant investments and expenses.[704] These are used to allocate cost items that cannot be readily categorized.[705]

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[697] Lyons Direct Testimony at 20.

[698] Lyons Direct Testimony at 20.

[699] Lyons Direct Testimony at 20.

[700] Lyons Direct Testimony at 20.

[701] Lyons Direct Testimony at 21.

[702] Lyons Direct Testimony at 21.

[703] Lyons Direct Testimony at 21.

[704] Lyons Direct Testimony at 21.

[705] Lyons Direct Testimony at 21.

In their direct testimony, the Attorney General/KIUC "strongly supported" the use of the 6-CP methodology in the development of KU's proposed COSS.[706] Additionally, Walmart and the DOD/FEA did not oppose the use of the 6-CP methodology.[707]

The Commission notes the 6-CP method allocates an additional $4.6 million to the residential class[708] as opposed to the 12-CP method which limits the impact on residential ratepayers.[709] The table below displays which classes benefit from the 6-CP methodology versus the 12-CP methodology:[710]

Demand Allocators					
KU	**6CP**	**%**	**12CP**	**%**	**6CP BENEFIT**
Total	**3,419,472**	**100.0%**	**3,156,223**	**100.0%**	**TO 12 CP**
RS	1,623,518	47%	1,328,975	42%	FALSE
GS	345,214	10%	353,557	11%	TRUE
AES	24,443	1%	24,220	1%	TRUE
PS-Secondary	271,106	8%	279,395	9%	TRUE
PS-Primary	15,417	0%	14,717	0%	TRUE
TOD-Secondary	290,563	8%	309,548	10%	TRUE
TOD-Primary	529,093	15%	527,535	17%	TRUE
RTS - Transmission	228,508	7%	229,450	7%	TRUE
FLS - Transmission	76,816	2%	78,848	2%	TRUE
LS & RLS	13,849	0%	9,233	0%	FALSE
LE	600	0%	400	0%	FALSE
TE	248	0%	248	0%	TRUE
OSL	53	0%	54	0%	TRUE
EV	44	0%	43	0%	TRUE

[706] Direct Testimony of Stephen J. Baron (Baron Direct Testimony) at 8.

[707] Direct Testimony of Jessica A. York (York Direct Testimony) at 3. Direct Testimony of Lisa V. Perry (Perry Direct Testimony) at 5.

[708] KU's Response to Staff's Fourth Request, Item 40b.

[709] Hearing Video Transcript (HVT) of the November 5, 2025 Hearing, Timothy S. Lyons at 02:16:10–012:17:03 PM. HVT of the November 6, 2025 Hearing, Leah Wellborn at 04:00:15–04:00:49 PM.

[710] Attorney General/KIUC's Response to Staff's Post-Hearing Request, Item 3, Table titled "Demand Allocators KU."

The table above demonstrates that the 6-CP methodology benefits commercial and industrial customers to the detriment of the residential rate class. With the 6-CP methodology, the residential class is allocated 47 percent of revenue requirement, while with the 12-CP methodology, the residential class is allocated 42 percent. The Commission notes that the 12-CP methodology reallocates no more the 2 percent of class revenue requirement to impacted rate classes. While the Commission will consider multiple NARUC- approved methodologies, the Commission notes its preference for the utilization of the 12-CP methodology, when reasonable, based on a utility's peaking characteristics.

In response to Staff's Post-Hearing Data Request, KU provided its FERC 12-CP test results.[711] The FERC 12-CP test aims to identify whether a production plant allocation methodology other than 12-CP is necessary given a utility's system peak characteristics. The first test determines if a 12-CP methodology is necessary given the difference between annual on-peak demand and off-peak demand. A result of 19 percent or less suggests a 12-CP methodology is acceptable to utilize for allocation of costs. The second test takes an average of the low annual peaks and divides it by the annual peak, a result of 66 percent or higher would indicate that a 12-CP methodology is acceptable. The third test takes the average peak and divides it by the overall annual peak, and if the results are 81 percent or higher, then the utility would benefit using a 12-CP methodology. The FERC 12-CP test results for KU are outlined in the table below:[712]

[711] KU's Response to Staff's Post-Hearing Request, Item 2.

[712] KU's Response to Staff's Post-Hearing Request, Item 2, Attachment "05-2025_PSC_DRPH_KU_Attach_to_Q2_-_FERC_12CP_Tests.xlsx."

FERC 12-CP Tests	Test Result	Threshold	Pass?
Test 1: On/Off Peak	13.57%	19% or Less	TRUE
Test 2: Low/Annual Peak	65.77%	66% or Higher	FALSE
Test 3: Average/Annual Peak	81.08%	81% or Higher	TRUE

KU stated that there is not definitive support for utilizing the 12-CP method.[713] However, based upon the results, two of the three tests for KU point towards the acceptability of utilizing the 12-CP methodology.

In regard to KU's classification of steam power production and maintenance expenses included in FERC Accounts 512 through 514, prior to the Stipulation, DOD/FEA originally argued that, since those accounts do not vary with energy, then those accounts should be classified as demand-related costs instead of energy-related costs.[714] In rebuttal testimony, KU agreed with the DOD/FEA's recommendation, in part. KU agreed that FERC Accounts 512 through 514 costs do not directly vary with energy production, however, the costs generally vary by the maintenance needs of the generating units related to utilization.[715] However, KU argued that the classification of FERC Accounts 512 through 514 do not have a substantial impact on class revenue targets, and has not prepared an analysis that identifies the costs compared by utilization of the units, so therefore, it is unable to support a different classification approach.[716] The results of

[713] KU's Response to Staff's Post-Hearing Request, Item 2.

[714] York Direct Testimony at 3.

[715] Rebuttal Testimony of Timothy S. Lyons (Lyons Rebuttal Testimony) at 7.

[716] Lyons Rebuttal Testimony at 7- 8.

shifting FERC Accounts 512 through 514 from energy-related costs to demand-related costs is illustrated in the table below:[717]

KU Rate Schedule	512-514 (Energy) Target Revenue Increase	512-514 (Demand) Target Revenue Increase	Current Revenues	512-514 (Energy) Class Increase	512-514 (Demand) Class Increase
RS	$104,186,935	$104,894,969	$741,466,479	14.1%	14.1%
GS	$26,744,962	$26,758,075	$272,241,062	9.8%	9.8%
AES	$1,519,896	$1,521,928	$13,171,291	11.5%	11.6%
PS-Sec	$17,648,181	$17,624,314	$179,971,469	9.8%	9.8%
PS-Pri	$995,692	$994,949	$10,183,697	9.8%	9.8%
TOD-Sec	$18,780,068	$18,671,380	$163,839,995	11.5%	11.4%
TOD-Pri	$35,383,292	$35,028,594	$308,400,771	11.5%	11.4%
RTS-Trans	$14,267,780	$14,081,198	$122,988,078	11.6%	11.4%
FLS	$2,715,057	$2,680,102	$23,206,906	11.7%	11.5%
LS & RLS	$3,808,994	$3,796,725	$31,822,538	12.0%	11.9%
LE	$44,729	$44,197	$382,365	11.7%	11.6%
TE	$27,692	$27,463	$252,098	11.0%	10.9%
OSL	$484	$484	$94,429	0.5%	0.5%
EV	$5,093	$5,093	$45,249	11.3%	11.3%
SSP	$181,347	$180,732	$189,766	95.6%	95.2%
BS	$5,716	$5,716	$53,798	10.6%	10.6%
Total	$226,315,920	$226,315,920	$1,868,309,993	12.1%	12.1%

The Stipulation did not explicitly discuss the approval of the 6-CP methodology, but it was approved in the catch-all provision from the Amended Stipulation.[718] The Commission finds that the use of the 6-CP methodology is not reasonable for KU, based upon the FERC 12-CP test results. The Commission notes that Test 2 only failed by approximately 0.23 percent.[719] Therefore, the Commission finds that KU's peaking patterns better align with the use of a 12-CP methodology based upon the FERC 12-CP test results. The Commission finds that KU should continue to evaluate the reasonableness of utilizing a 12-CP methodology through the use of the FERC 12-CP

[717] Lyons Rebuttal Testimony, Table 3 at 8.

[718] Amended Stipulation, Section 11.1.

[719] KU's Response to Staff's Post-Hearing Request, Item 2.

tests in its next base rate case filing. Furthermore, KU should conduct separate COSSs that use 12-CP, 6-CP, and 4-CP in its next base rate case filing. KU should also evaluate the cost of service for Group 1 and Group 2, as it relates to rider mechanisms such as the GCR, in light of the possible additional data center load and provide the analysis in its next base rate case filing. The Commission also finds that KU should prepare an analysis that identifies the FERC Account 512 through 514 costs not related to utilization as compared to expenses related to utilization in its next base rate case filing.

REVENUE REQUIREMENT INCREASE ALLOCATION

In its application, KU stated that its proposed rate design aims to be in line with the results of the COSS on a gradual basis.[720] KU proposed to limit the revenue requirement increase by class to the system average of approximately 11.45 percent.[721] KU stated that the results of the COSS show there are notable differences in the rate of return on rate base between the rate classes, and due to that, some classes are subsidizing other rate classes.[722] KU did not propose to eliminate the interclass subsidies; however, KU proposed to recover larger portions of the revenue requirement increase from rate classes with lower rates of return and smaller portions from classes with higher rates of return.[723] KU stated that to bring the rates of return closer to the system average and to gradually reduce interclass subsidies, KU proposed to set rates that, in aggregate, move toward

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[720] Direct Testimony of Michael E. Hornung (Hornung Direct Testimony) at 2-3.

[721] Direct Testimony of Andrea M. Fackler (Fackler Direct Testimony) at 31.

[722] Fackler Direct Testimony at 31.

[723] Fackler Direct Testimony at 31-32.

earning the overall system rate of return on rate base.[724] A summary of the proposed revenue requirement increase allocation per rate class is illustrated in the table below:[725]

KU Rate Class	Proposed Revenues ($)	Current Revenues ($)	Proposed Increase ($)	Proposed Increase (%)
Residential Service (RS)	$818,635,464	$719,177,506	$99,997,335	13.55%
Residential Time-of-Day Service (RTOD)	$200,147	$188,616	$23,833	13.05%
General Service (GS)	$295,693,753	$274,522,836	$25,335,181	9.21%
General Time-of-Day Service (GTOD)	$31,584	$29,115	$2,400	8.22%
All Electric School Service (AES)	$14,343,556	$13,309,726	$1,449,553	10.91%
Power Service Secondary (PSS)	$195,467,072	$183,260,971	$16,713,426	9.15%
Power Service Primary (PSP)	$11,032,340	$10,292,807	$942,362	9.14%
Time-of-Day Secondary Service (TODS)	$178,071,084	$159,835,957	$17,929,669	10.87%
Time-of-Day Primary Service (TODP)	$335,049,877	$288,026,598	$33,834,832	11.15%
Retail Transmission Service (RTS)	$136,456,613	$103,322,454	$13,634,683	11.00%
Special Contract	$62,818,712	$21,419,771	$7,990,265	14.40%
Fluctuating Load Service (FLS)	$38,844,904	$32,457,617	$2,538,016	6.90%
Lighting Energy Service (LE)	$420,277	$361,234	$42,734	11.14%
Traffic Energy Service (TE)	$273,463	$231,651	$26,391	10.58%
Outdoor Sports Lighting Service Secondary (OSL)	$98,153	$105,689	($37)	(0.04%)
Lighting Service & Restricted Lighting Service (LS & RLS)	$35,355,912	$30,640,400	$3,624,095	11.37%
Total	**$1,911,429,380**	**$2,142,658,883**	**$224,079,832**	**11.68%**

[724] Fackler Direct Testimony at 32.

[725] Application, Filing Requirements, Vol. 10, Tab 66, Schedule M-2.1.

Prior to the Stipulation, the Attorney General/KIUC stated that the proposed revenue requirement increase allocation moves rates towards the cost to serve.[726] However, if the Commission were to authorize a lower-than-ask revenue increase, the Attorney General/KIUC originally argued that a portion of the revenue reduction should be applied to reduce interclass subsidization paid by TODP, RTS, FLS, and that the remaining revenue adjustment should be allocated on a uniform percentage basis.[727] Additionally, the Attorney General/KIUC suggested that for the residential class, the Commission should set the basic service charge at the same percentage to mirror the increase to the rate class revenue increase.[728]

Prior to the Stipulation, Walmart stated that, at the proposed revenue requirement, Walmart did not oppose the proposed allocation of revenue.[729] Walmart continued to argue that, should the Commission authorize a lower revenue requirement, that the Commission should apply 50 percent of the revenue reduction to rate classes paying in excess of their cost-based levels and then spread the remaining revenue evenly on an percentage basis.[730]

Prior to the Stipulation, the DOD/FEA's witness York argued in her direct testimony that KU's proposed revenue requirement increase allocation does not make a meaningful movement toward each class's cost-to-serve.[731] York recommended a 30 percent

[726] Baron Direct Testimony at 5.

[727] Baron Direct Testimony at 5-6.

[728] Baron Direct Testimony at 33.

[729] Perry Direct Testimony at 5.

[730] Perry Direct Testimony at 5-6.

[731] York Direct Testimony at 3.

movement towards the cost-to-serve; however, York stated that none of the major rate classes should receive an increase greater than 1.5 times the system average of KU.[732]

In rebuttal testimony, KU agreed with the Attorney General/KIUC's recommendations, in part, stating the recommendation is generally consistent with KU's approach to rate setting.[733] However, KU did not agree with the increase cap to the residential basic service charge associated mirroring the revenue increase to the class.[734] KU also did not agree with applying the revenue increase first to reduce the subsidies related to rate schedules TODP, RTS, and FLS, stating that the recommendation would create disparities in the movement to cost-based rates since some classes move at a faster pace to cost-based rates than other rate classes.[735]

In rebuttal testimony, KU did not agree with Walmart's recommendation on applying a 50 percent revenue reduction to rate classes paying in excess of cost-based levels, stating that KU continues to support the proposed revenue allocation.[736] KU explained that the proposal reflects a uniform movement to cost-based rates and strikes an appropriate balance between a movement to cost-based rates and the principle of gradualism.[737]

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[732] York Direct Testimony at 3.

[733] Lyons Rebuttal Testimony at 2.

[734] Lyons Rebuttal Testimony at 3.

[735] Lyons Rebuttal Testimony at 3.

[736] Lyons Rebuttal Testimony at 15.

[737] Lyons Rebuttal Testimony at 15.

KU also did not agree with the DOD/FEA's recommendation of a 30 percent movement towards cost-based rates, stating that a 30 percent movement would not align with bill continuity and bill impact considerations.[738]

In regard to the revenue requirement increase allocation, the Stipulation contained an agreement to reduce the subsidization provided by KU's FLS, RTS, TODP, and TODS rates.[739] The subsidy reductions are outlined as follows:[740]

KU Rate Class	Proposed Increase	Subsidy Reduction	Stipulated Increase after Subsidy Reduction[741]
Fluctuating Load Service	$2,528,016	($382,665)	$2,145,351
Retail Transmission Service	$13,634,683	($2,518,169)	$11,116,514
Time-of-Day Primary Service	$33,834,832	($7,910,739)	$25,924,093
Time-of-Day Secondary Service	$17,929,669	($1,201,286)	$16,728,383

The Stipulation also revised the dollar amount and percentage of allocated revenue to each rate class due to the reduction of the overall revenue requirement. The table below compares the original proposed revenue requirement increase allocation and the stipulated revenue requirement increase allocation:[742]

KU Rate Class	Proposed Increase ($)	Proposed Increase (%)	Stipulated Increase ($)	Stipulated Increase (%)	Difference ($) (Proposed – Stipulated)
Residential Service (RS)	$99,997,335	13.55%	$49,584,466	6.74%	$50,412,869
Residential Time-of-Day Service (RTOD)	$23,833	13.05%	$11,326	6.22%	$12,507
General Service (GS)	$25,335,181	9.21%	$20,418,932	7.43%	$4,916,249

[738] Lyons Rebuttal Testimony at 9-10.

[739] Stipulation, Article 5.4. .

[740] Stipulation Testimony, Exhibit 1 at 1.

[741] This does not include the further adjustments made to reach the stipulated revenue increases.

[742] Stipulation Testimony, Exhibit 1 at 1, and Application, Filing Requirements, Vol. 10, Tab 66, Schedule M-2.1.

KU Rate Class	Proposed Increase ($)	Proposed Increase (%)	Stipulated Increase ($)	Stipulated Increase (%)	Difference ($) (Proposed – Stipulated)
General Time-of-Day Service (GTOD)	$2,400	8.22%	$1,934	6.64%	$466
All Electric School Service (AES)	$1,449,553	10.91%	$1,168,270	8.83%	$281,283
Power Service Secondary (PSS)	$16,713,426	9.15%	$13,470,214	7.39%	$3,243,212
Power Service Primary (PSP)	$942,362	9.14%	$759,498	7.38%	$182,864
Time-of-Day Secondary Service (TODS)	$17,929,669	10.87%	$13,482,268	8.19%	$4,447,401
Time-of-Day Primary Service (TODP)	$33,834,832	11.15%	$20,893,566	6.90%	$12,941,266
Retail Transmission Service (RTS)	$13,634,683	11.00%	$8,959,373	7.25%	$4,675,310
Special Contract	$7,990,265	14.40%	$3,850,069	6.97%	$4,140,196
Fluctuating Load Service (FLS)	$2,528,016	6.90%	$1,729,049	4.73%	$798,967
Curtailable Service Riders (CSR)	N/A	0.00%	($7,288,554)	40.00%	($7,288,554)
Lighting Energy Service (LE)	$42,734	11.14%	$34,442	9.02%	$8,292
Traffic Energy Service (TE)	$26,391	10.58%	$21,270	8.55%	$5,121
Outdoor Sports Lighting Service Secondary (OSL)	($37)	(0.04%)	($30)	(0.03%)	($7)
Electric Vehicle Charging Service (EVC)	$5,093	30.13%	$4,105	24.28%	$988
Lighting Service & Restricted Lighting Service (LS & RLS)	$3,624,095	11.37%	$2,920,846	9.16%	$703,249
Total	**$224,079,832**	**11.68%**	**$130,021,043**	**6.79%**	**$94,058,789**

The Commission finds the stipulated, subsidy reductions to be reasonable and should be applied to the Commission's revenue requirement increase allocation. Based on the Commission-approved revenue requirement increase of $128,499,951, the Commission finds that the revenue requirement increase should be allocated as follows:

KU Rate Class	Commission Increase ($)	Commission Increase (%)
Residential Service (RS)	$48,141,526	6.54%
Residential Time-of-Day Service (RTOD)	$10,985	6.04%
General Service (GS)	$19,944,737	7.26%
General Time-of-Day Service (GTOD)	$1,733	5.95%
All Electric School Service (AES)	$1,141,019	8.62%
Power Service Secondary (PSS)	$13,146,637	7.21%
Power Service Primary (PSP)	$741,777	7.21%
Time-of-Day Secondary Service (TODS)	$13,182,081	8.01%
Time-of-Day Primary Service (TODP)	$20,413,585	6.74%
Retail Transmission Service (RTS)	$8,743,316	7.08%
Special Contract	$3,735,989	6.76%
Fluctuating Load Service (FLS)	$1,689,642	4.62%
Lighting Energy Service (LE)	$33,649	8.81%
Traffic Energy Service (TE)	$20,792	8.36%
Outdoor Sports Lighting Service Secondary (OSL)	($81)	(0.08%)
Electric Vehicle Charging Service (EVC)	$4,213	24.93%
Lighting Service & Restricted Lighting Service (LS & RLS)	$2,853,714	8.97%
Total	**$125,936,314**	**6.17%**

The Commission notes that due to rate rounding, there is a variance of approximately (1.99) percent or $(2,563,637) of rate revenue recovery.

RATE DESIGN

KU stated that its proposed rate design, in its application, continues to bring both the structure and the charges in line with the results of the COSS.[743] KU did not propose to alter the existing rate structure of its residential rate, meaning it will still consist of a daily basic service charge and a volumetric, per-kWh energy charge.[744] However, the overall rate was proposed to receive a gradual increase towards its true cost-of-service.[745]

Prior to the Stipulation, the Attorney General/KIUC stated that, while KU's proposed residential basic service charge increases may be substantial, the charges are still below the cost to serve.[746] The Attorney General/KIUC originally recommended the proposed residential basic service charges be approved as filed; however, if the revenue requirement increase granted were less than proposed, they argued a portion of the Commission's revision should be applied to the respective basic service charge of the rate to reduce the percentage increase to the level of the overall rate class increase.[747]

In regard to the rate design for TODP, FLS and RTS, the Attorney General/KIUC recommended that the proposed demand charges should be increased on a revenue neutral basis by lowering the energy charges.[748] The Attorney General/KIUC stated that this revision is necessary in order to reflect the actual variable production costs.[749]

[743] Hornung Direct Testimony at 2.

[744] Hornung Direct Testimony at 3.

[745] Hornung Direct Testimony at 3.

[746] Baron Direct Testimony at 31.

[747] Baron Direct Testimony at 32-33.

[748] Baron Direct Testimony at 38.

[749] Baron Direct Testimony at 6.

Prior to the Stipulation, the DOD/FEA recommended moving the recovery of certain steam generation expenses from the energy charge to the demand charges, to better align to the cost-of-service.[750]

The Joint Intervenors recommended that the proposed increase to the basic service charges should be denied and remain at the existing levels.[751] Walmart did not oppose KU's proposed rate design.[752]

The Stipulation revised KU's proposed rates to fit the stipulated revenue requirement increase. The Stipulation limited the overall residential rate increase, and the residential basic service charge increase percentage, to be capped at the system average.[753] The Stipulation also reduced rate LS to reflect the reduction in cost of capital and made a revenue neutral change to rates RTS and TODP.[754]

The Commission finds the stipulated revisions to rates LS, RTS, and TODP, to be reasonable. However, the Commission made additional adjustments to the rate design that need to be addressed. The Commission took the stipulated rate design, as well as other stipulated rate considerations, and adjusted the rates to account for the change in the revenue requirement increase. Based upon the Commission's allocation of the approved revenue requirement increase; the resulting bill impacts from the Commission-approved rates are as follows:

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[750] York Direct Testimony at 3.

[751] Direct Testimony of Roger D. Colton (Colton Direct Testimony) at 7.

[752] Perry Direct Testimony at 6.

[753] Stipulation, Article 5.3.

[754] Stipulation, Article9.8..

KU Rate Class	Commission Bill Impact ($)	Commission Bill Impact (%)
Residential Service (RS)	$8.73	6.54%
Residential Time-of-Day Service (RTOD)	$8.54	6.04%
General Service (GS)	$19.21	7.26%
General Time-of-Day Service (GTOD)	$143.48	$5.95
All Electric School Service (AES)	$247.28	8.62%
Power Service Secondary (PSS)	$273.43	7.21%
Power Service Primary (PSP)	$312.08	7.21%
Time-of-Day Secondary Service (TODS)	$1,357.67	8.01%
Time-of-Day Primary Service (TODP)	$6,401.19	6.74%
Retail Transmission Service (RTS)	$34,695.70	7.08%
Special Contract	$311,332.45	6.76%
Fluctuating Load Service (FLS)	$140,803.48	4.62%
Lighting Energy Service (LE)	$17.13	8.81%
Traffic Energy Service (TE)	$1.50	8.35%
Outdoor Sports Lighting Service Secondary (OSL)	($1.12)	(0.08%)
Electric Vehicle Charging Service (EVC)	$0.22	25.00%
Lighting Service & Restricted Lighting Service (LS & RLS)	$1.31	8.95%

Based upon the record, and otherwise being sufficiently advised, the Commission finds its revisions to the stipulated rates, as reflected in Appendix E to this Order reasonable and should be accepted.

OTHER RATE DESIGN ISSUES

PS Demand Structure. KU proposed to change the PS demand rates from a non-time differentiated seasonal demand rate to the same structure as the TODS, TODP, and RTS rates.[755] KU explained that, because AMI is fully deployed, it now has metering for all PS customers allowing for a more granular demand rate structure.[756] The PS demand rates would change from a per kW to a per kVA charge.[757]

The Stipulation did not explicitly discuss the approval of the revisions to the PS demand structure, but it was approved in the catch-all provision from the Amended Stipulation.[758]

The Commission acknowledges that the use of AMI provides more granular data for each customer class. The Commission agrees that, if the technology available is implemented, that a more granular demand rate structure is beneficial to customers. The Commission finds the proposed change to the PS demand structure to be reasonable and that it should be accepted.

Seasonal Residential Rates – In the Stipulation, the Signing Parties agreed that KU will study seasonal residential rates in preparation for its next base rate case.[759] Additionally, the results would be included in the next general base rate adjustment

[755] Hornung Direct Testimony at 9.

[756] Hornung Direct Testimony at 9.

[757] Hornung Direct Testimony at 9.

[758] Amended Stipulation, Section 11.1.

[759] Stipulation, Article 9.3.

filing.[760] The Commission agrees that seasonal residential rates should be studied, finds that the stipulated issue is reasonable, and should be accepted.

Curtailable Service Riders – In its application, KU did not propose to increase the curtailable service rider credits (CSR-1 and CSR-2). The Commission ordered in Case No. 2023-00422 that KU and LG&E should evaluate the expansion of the CSR programs.[761] KU analyzed a 100 MW expansion of the CSR-2 program and it was determined to be uneconomical in all scenarios.[762] KU analyzed a hypothetical CSR offering with the following characteristics and constraints:[763]

- 100 MW capacity;
- No buy-through option;
- No advance notice requirement;
- No noncompliance provision;
- Maximum physical curtailment hours per year: 100;
- Maximum physical curtailment events per year: 20;
- Maximum physical curtailment events per day: 2; and
- Companies may request physical curtailment only when all available units have been dispatched or are being dispatched.

The hypothetical CSR program would support the following credits:[764]

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[760] Stipulation, Article 9.3.

[761] Case No. 2023-00422, *Electronic Investigation of Louisville Gas and Electric Company and Kentucky Utilities Company Service Related to Winter Storm Elliott* (Ky. PSC, Jan. 7, 2024), Order at 43.

[762] Schram Direct Testimony at 29.

[763] Schram Direct Testimony at 29-30.

[764] Schram Direct Testimony at 30.

CSR Credits for Hypothetical CSR Program	
Transmission	$3.38 per kVA-month
Primary	$3.44 per kVA-month

KU stated that, for an expanded CSR to be supportive of system reliability, it would need to reflect the characteristics of the avoided capacity resource better, contain no buy-through option, have no advanced notice requirement, have noncompliance provision, and have no limits on system conditions.[765] KU explained all of the above characteristics and constraints are unlikely to be attractive to potential CSR customers.[766]

Prior to the Stipulation, the Attorney General/KIUC stated that curtailments are likely to be more common in the future, as data center load growth increase with the lack of new dispatchable generation neighboring areas.[767] Additionally, the Attorney General/KIUC stated that the CSR demand credits have increased by less than $1.00 over the past 16 years.[768] The Attorney General/KIUC recommended increasing the CSR credits by $2.50, as well as the non-compliance penalty, due to the factors stated above and revision to the avoided cost calculations, as shown below:[769]

Calculation of CSR Avoided Capacity Rate Based on a 2028 Simple Cycle Combustion Turbine	
Revenue Requirement	$36,726,075
Winter MW	258

[765] Schram Direct Testimony at 30.

[766] Schram Direct Testimony at 30.

[767] Baron Direct Testimony at 43.

[768] Baron Direct Testimony at 44.

[769] Baron Direct Testimony, Table 17 at 47.

Summer MW	243
Winter Reserve Margin	29%
Winter MW Load Served[770]	200
Fixed Revenue Requirement/Winter kW-year	183.63
Avoided Capacity Costs per kW-month	**$15.30**

Although the CSR rates could be increased to $15.30 per kW-month, the Attorney General/KIUC stated that the recommended $2.50 increase is consistent with the principle of gradualism and was determined to be a more reasonable than the full cost-based increase.[771]

In rebuttal testimony, KU stated the current CSR rates are reasonable, and that the Attorney General/KIUC's recommendation overstates avoided costs.[772] KU stated that it does not utilize all existing CSR capacity, and that the level of current use does not suggest that increased CSR rates will be necessary to combat increased future use.[773] Additionally, KU stated that its recent IRP and CPCN analyses have shown that battery energy storage is more economical than a simple cycle combustion turbine, and thus, the combustion turbine is an inappropriate proxy for the avoided capacity cost calculations.[774] However, KU did agree that any CSR credit increase should include a symmetrical increase to the non-compliance penalty.[775]

[770] Simple Cycle Combustion Turbine Capacity adjusted for Winter Reserve Margin.

[771] Attorney General/KIUC's Response to KU's First Request, Item 7.

[772] Rebuttal Testimony of Charles R. Schram (Schram Rebuttal Testimony) at 1.

[773] Schram Rebuttal Testimony at 2.

[774] Schram Rebuttal Testimony at 3.

[775] Schram Rebuttal Testimony at 5.

The Stipulation agreed to 40 percent CSR-1 and CSR-2 credit and penalty increases.[776] The increases would be as follows:

	Current per kW-Month	Stipulated per kW-Month
CSR-1 Transmission	($3.20)	($4.48)
CSR-1 Primary	($3.31)	($4.63)
CSR-2 Transmission	($5.90)	($8.26)
CSR-2 Primary	($6.00)	($8.40)
Non-Compliance Charge	$16.00	$22.40

The Commission acknowledges the benefits the CSR credits have for both KU and the curtailable customers. The Commission notes that, although the level of current curtailments may not warrant an increase on a standalone basis, the uncertainty of how data center load growth might impact the value of expanding the curtailable riders does. The Commission agrees with the Attorney General/KIUC's avoided cost analysis that shows the credits need a much greater increase than recommended and agreed upon. However, in the interest of gradualism, the Commission finds that the stipulated curtailable service rider rates and charges are reasonable and should be approved.

Outdoor Sports Lighting and Streetlighting Issues – In KU's last base rate case, the Commission ordered KU to develop a plan to market outdoor sports lighting (OSL) more effectively.[777] KU stated in its application that it sought to increase awareness of OSL by creating a website which provides details on the rate, explains how it works, and the eligibility requirements.[778] KU stated that a specialist reaches out to any customers who submit an interest form via the website and discusses the rate more in detail.[779]

[776] Stipulation, Article 9.11.

[777] Case No. 2020-00349, June 30, 2021 Order at 49.

[778] Direct Testimony of Shannon L. Montgomery (Montgomery Direct Testimony) at 22.

[779] Montgomery Direct Testimony at 22.

Additionally, KU stated that the company has proactively reached out to customers who could benefit from switching to the rate from other offered lighting rates[780] KU explained that customers were very receptive to its marketing efforts, although some customers prefer other non-demand rate offerings.[781]

In the Stipulation, KU agreed to commit to continue its proactive streetlight inspections and smart streetlight efforts for LFUCG and Louisville Metro.[782]

The Commission encourages KU to continue its efforts on increasing participation for OSL. The Commission expects an update on the outreach efforts and participation in OSL in its next base rate case. The Commission finds that KU's stipulated commitment to continue its proactive streetlight inspections to be reasonable and that it should be accepted.

Special Charges – KU proposed, in its application, to increase its Special Charges using 2024 actual costs with an inflation adjustment of approximately 1-3 percent.[783] The Special Charges include Disconnect/Reconnect Charge, Returned Check Fee, Meter-Test Charge, Meter Pulse Relaying charge, Unauthorized Connection, Inspection, and Additional Trip charges.[784]

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[780] Montgomery Direct Testimony at 22.

[781] Montgomery Direct Testimony at 22.

[782] Stipulation, Article 9.14.

[783] Lyons Direct Testimony at 29.

[784] Lyons Direct Testimony at 29.

The inflation factor utilized by KU was derived from the wage index assumption[785] as part of the application.[786] KU stated that inflation factors were previously approved in the Special Charges in the prior two base rate case filings.[787] The Special Charges noted to have the inflation increase included were the meter pulse charge and returned check charge.

The Stipulation did not explicitly address the Special Charges, but it was approved in the catch-all provision from the Amended Stipulation.[788]

The Commission is concerned that an inflation adjustment to Special Charges, which are intended to reflect actual costs incurred to perform non-recurring duties and now may not accurately recover the true cost to perform. The Commission notes that although an inflation adjustment was included, and approved, in the last two base rate cases[789], it is important that non-recurring charges reflect only the marginal costs related to the service performed.[790] The Commission finds that Special Charges should only reflect the actual cost and has removed the inflation factor from the charge calculations. The Commission finds that the Special Charges included in Appendix E to this Order are reasonable and should be approved.

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[785] Application, Tab 60, Attachment 3 at 28.

[786] KU's Response to Staff's Post-Hearing Request, Item 51(a).

[787] KU's Response to Staff's Post-Hearing Request, Item 51(b).

[788] Amended Stipulation, Section 11.1.

[789] Case No. 2018-00294, *Electronic Application Kentucky Utilities Company for an Adjustment of its Electric Rates* (Ky. PSC Apr. 30, 2019), Order at Appendix B; Case No. 2020-00349, June 30, 2021 Order at 49-50.

[790] Case No. 2020-00141, *Electronic Application of Hyden-Leslie County Water District for an Alternative Rate Adjustment* (Ky. PSC Nov. 6, 2020), Order at 19-20. See also, Case No. 2020-00349, June 30, 2021 Order at 49-50.

COST ALLOCATION MANUAL

According to the application, subsequent to the last general rate adjustment for KU, on May 25, 2022, LG&E/KU's parent company, PPL, completed the acquisition of The Narragansett Electric Company d/b/a Rhode Island Energy (NECO) from National Grid USA.[791] During the integration of NECO into PPL's operations, LG&E/KU stated that PPL took the opportunity to share best practices, consider a more consolidated shared services approach, and improve operational efficiency to reduce costs for the retail customers of its utility operations.[792] According to KU, as a result of this acquisition and restructuring, certain services that had been exclusively performed for LG&E/KU by LKS would now be provided by PPL Services.[793] In its application, KU tendered a cost allocation manual with supporting testimony.[794] KU also filed the ratios used to calculate the allocations from the PPL subsidiaries.[795]

According to LG&E/KU, the application of the cost allocation ratios and manual were audited and found by an independent agency to be reasonable.[796] In direct testimony, LG&E/KU stated "[c]harges, including supporting documentation, are reviewed monthly for reasonableness. Any new or unusual charges are questioned before

[791] Garrett Direct Testimony at 1-2.

[792] Garrett Direct Testimony at 1-2.

[793] Garrett Direct Testimony at 2.

[794] Application, Tab 51; Garrett Direct Testimony.

[795] KU's Response to Staff's Second Request, Item 75, Attachment.

[796] Garrett Direct Testimony at 3. "PPL Corporate Audit Department, in accordance with the International Standards for the Professional Practice of Internal Auditing and the COSO 2013 Internal Control Integrated Framework, completed an audit in 2023 and determined that PPL and LG&E and KU Energy LLC ("LKE") direct and indirect costs were allocated in accordance with the CAM, were calculated properly and adequately supported, and the cost assignment methods used were reasonable."

recording to the general ledger." However, in response to several requests for information as well as at the hearing, LG&E/KU could not identify that any particular group or person reviewed the charges or expenses allocated to KU. Specifically, "[c]osts allocated to KU are reviewed by several departments including the PPL ServicesCorporate Budgeting department and the LKS Corporate Accounting department."[797] At the hearing, KU confirmed that it was not aware if anyone affiliated solely with KU or LG&E reviewed the expenses prior to approval.[798]

The intervenors did not address the issue of accepting the cost allocation manual or concerns thereof. The Stipulation, likewise, was silent on the issue until such time as was amended to contain a catch-all provision.[799]

The Commission accepts the cost allocation manual tendered by KU. However, the Commission has concerns about the review of the allocation of expenses. In 2004, Liberty Consulting Group performed a focused management audit on LG&E/KU fuel procurement. As part of this audit, affiliate transactions were examined as was the cost allocation manual at the time. As early as 2004, there were concerns about the separation of activities of the affiliates within the companies and steps that could be taken to prevent issues.[800] The Commission has concerns about the appearance of lack of controls and

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[797] KU's Response to Staff's Second Request, Item 76.

[798] HVT of November 4, 2025 Hearing, Cross of Christopher Garrett 03:31:20–03:32:34.

[799] Amended Stipulation.

[800] For example, "[t]he Data Entry Clerk handles all CSMS data entry for WKE as well as some of the data entry for both KU and LG&E. Because there is no separation between these duties for the Utilities and WKE, this individual would have the opportunity to make data comparisons and adjust data entries to favor one entity to the detriment of the other. This organizational arrangement is a weakness in affiliate-relations controls and violates one of the basic standards of organizational separation of responsibilities." Audit at Page V-14.

monitoring for the cost allocations. Cost allocations involve the PPL Corporate Budgeting department and the LKS Corporate Accounting department, in part.[801] LG&E/KU are allocated separate expenses, but the employees allocating the expenses may or may not work for the LG&E or KU but instead a parent or subsidiary or a combination thereof The company receiving the allocation may or may not review the cost independently and several groups review allocations but are also, in some cases, employed by the company deciding to allocate the costs.

Even if LG&E/KU pursue the merger, the Commission expects KU to address the lack of independent review of costs allocated to KU. The Commission recommends that KU and LG&E delegate an employee(s) reporting solely to KU or to LG&E with responsibility to review the cost allocations. Also, the Commission recommends that KU ensure that costs are being appropriately allocated by creating a review process independent of other affiliates or subsidiaries. In addition, KU should include a report with its next general rate adjustment application detailing how the utilities have taken steps to ensure that costs are allocated appropriately including any new policies or procedures instituted to ensure independent review of the allocation of costs.

POLE ATTACHMENT RATES

LG&E/KU[802] have had joint pole attachment rates since approximately 2010.[803] LG&E/KU proposed to split their current single wireline pole attachment charge, $7.25

[801] KU's Response to Staff's Second Request, Item 76.

[802] Since LG&E and KU filed a combined rate, the references in this section will be to them as a joint entity unless referenced separately for each Order.

[803] Direct Testimony of Michael Hornung (Hornung Direct Testimony) at 13.

into a two-user charge, $10.13 and a three-user charge, $10.46,[804] to more closely align with the Commission's Order in Administrative Case No. 251.[805] In addition, LG&E/KU proposed to increase the Linear Foot Duct fee from $0.81 and $1.22 as well as the wireless facility company pole from $36.25 to $51.46.[806] In support of the proposed rates, LG&E/KU argued the cost of service is higher than the $7.25 that has been in place since 2016.[807] According to the application, the proposed rates reflect the current cost to serve those customers.[808]

Subsequently, LG&E/KU revised its request to eliminate the inclusion of KU's inventory in Virginia.[809] As a result, the cost supported two-user pole attachment rate was $10.23 and the three-user pole attachment rate was $10.48.[810]

KBCA provided testimony on the pole attachment proposals of the companies. According to its witness, Patricia Kravtin, there were three fundamental issues with the way the companies calculated their rate. According to KBCA, LG&E/KU, as two separate entities, should not have a combined pole attachment rate.[811] KBCA argued the companies are separate entities, with separate costs structures, and file FERC and other

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[804] Hornung Direct Testimony at 13.

[805] Hornung Direct Testimony at 12; *See also* Administrative Case No. 251 *Adoption of a Standard Methodology for Establishing Rates for CATV Pole Attachments* (Ky. PSC Sept. 17, 1982).

[806] Hornung Direct Testimony, Exhibit MEH-1.

[807] Hornung Direct Testimony at 12; Case No. 2016.

[808] Hornung Direct Testimony at 12. The original application included KU inventory in Virginia.

[809] LG&E/KU's Response to KBCA's Second Request, Item 2.

[810] LG&E/KU's Response to KBCA's Second Request, Item 2.

[811] Direct Testimony of Patricia Kravtin (Kravtin Direct Testimony) (filed Aug. 29, 2025) at 6.

regulatory filings separately.[812] LG&E/KU responded that they have had a combined rate for over a decade.[813] According to the testimony the combined rate for the entities was part of a settlement in its 2014 general rate adjustment[814] filing to which the predecessor organization to the KBCA, the Kentucky Cable Telecommunications Association (KCTA), was a signatory to the settlement agreement.[815] In 2016, the Commission approved the combined entity rate.[816] However, the companies did provide the rate calculation as separate entities.[817] KU calculated rates of $8.65 per attachment for a two-user pole and $8.80 per attachment for a three-user pole.[818]

KBCA also argued the rates calculated by LG&E/KU depend on “forecasted” data for most of its cost inputs, rather than publicly reported, actual historical embedded cost

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[812] Kravtin Direct Testimony at 6.

[813] Rebuttal Testimony of Michael Hornung (Hornung Rebuttal Testimony) (filed Sept. 30, 2025) at 19.

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

[815] See Case No. 2014-00371, June 30, 2015 Order, Appendix A; Case No. 2014-00372, June 30, 2015 Order, Appendix A. The testimony, Hornung Rebuttal Testimony at 19 also cited to Case No. 2014-00371, Settlement Testimony of Kent W. Blake Exhibit 1, Settlement Agreement, Settlement Exhibit 4, KU Tariff, Kentucky Utilities Company P.S.C. No. 17, Original Sheet No. 40 (Apr. 20, 2015) (showing KU’s proposed attachment charge of $9.69 and the settled rate of $7.25); Case No. 2014-00372, Settlement Testimony of Kent W. Blake Exhibit 1, Settlement Agreement, Settlement Exhibit 5, LG&E Electric Tariff, Louisville Gas and Electric Company P.S.C. Electric No. 10, Original Sheet No. 40 (Apr. 20, 2015) (showing LG&E’s proposed attachment charge of $9.11 and the settled rate of $7.25).

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

[817] KU’s Response to Staff’s First Request, Item 55, 2025 PSC DR1 KU LGE Attach to Q54 – Exhibit MEH-1 – PSA Rate Support.

[818] Kravtin Direct Testimony at 7; referring to LG&E/KU’s response to Staff’s First Request, Item 54, Attachment.

data as directed in Administrative Case No. 251.[819] In response to this argument, LG&E/KU stated that the methodology has been the same since 2014; additionally, the net plant calculations are based on historical costs through January 31, 2025, not projections; only the expenses are forecasted for rate purposes.[820] LG&E/KU argued that its methodology is consistent with Administrative Order 251 in the calculation of “embedded costs”.[821]

KBCA’s last critique relates to the information used in the calculation itself. According to KBCA the calculation included “additional ‘revenue requirement’ allocations of common plant and cash working capital without direct cost-causative links to pole attachments”.[822] KBCA also alleged that LG&E/KU used a blended maintenance and operations carrying charge factor including allocations and assumptions instead of a simple formula.[823] In response, LG&E/KU stated that common plant and cash working capital are common costs, which are not recovered elsewhere in the pole attachment rate formula, and argued that it was appropriate to recover an equitable share of such costs from pole attachment customers.[824] KBCA and LG&E/KU disagreed with the appropriate rate of return to apply as well.[825]

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[819] Kravtin Direct Testimony at 6.

[820] Hornung Rebuttal Testimony at 20.

[821] Hornung Rebuttal Testimony at 20-21.

[822] Kravtin Direct Testimony at 17.

[823] Kravtin Direct Testimony at 17-18.

[824] Hornung Rebuttal Testimony at 23-24.

[825] Kravtin Direct Testimony at 15; Hornung Rebuttal Testimony at 21-22.

KBCA proposed rates for the individual utilities. For KU, KBCA initially proposed a two-user rate of $7.10 and a three-user rate of $7.13, both of which are less than the current $7.25 charge.[826] KBCA provided revised rates based on additional information and revisions by KU and proposed that the charge be $6.83 for a two-user attachment and $6.86 for a three-user attachment.[827]

In the Stipulation, the Stipulating Parties, which did not include KBCA, agreed to the following rates: Two-User Wireline Attachment Rate - $9.79; Three-User Wireline Attachment Rate - $10.12; Linear Foot of Duct - $1.16; and Wireless Facility on top of pole - $49.76.[828] The Stipulating Parties stated they agreed to the rates as they reflect the stipulated return on equity and updated long-term debt rate.[829]

KBCA was not a signatory to the Stipulation in this case. In its brief, KBCA argued that the failure to use the correct calculation methodology makes it impossible for the Commission to establish fair, just and reasonable rates.[830] KBCA also alleged that LG&E/KU used forecasted expenses when actual expense amounts were available and the utilities' combined rate is not permissible.[831] Overall, KBCA stated that the Commission could not approve the proposed rates because they were not calculated in compliance with Administrative Order 251.[832]

[826] Kravtin Direct Testimony at 18-19.

[827] KBCA's Filing of Kravtin's workpapers and hearing exhibit (filed Nov. 7, 2025); Workpaper KU PSA Excluding Virginia.

[828] Stipulation, Article 9.6.

[829] Stipulation Testimony at 24.

[830] KBCA's Post-Hearing Brief (filed Dec. 2, 2025) at 6.

[831] KBCA's Post-Hearing Brief at 16-21.

[832] KBCA's Post-Hearing Brief, generally.

In its brief, LG&E/KU argued that "embedded" does not mean historical and that the Commission is to treat pole attachment rates the same for ratemaking purposes.[833] LG&E/KU requested the Commission adopt the proposed rates in the Stipulation as the 35-40 percent increase is consistent with the rise in costs, in light of the rates remaining constant for approximately a decade. According to LG&E/KU, Ms. Kravtin provided testimony in the 2014 rate case, that the appropriate rate for LG&E for a two-user pole was $5.17,[834] and in this case KBCA calculated the appropriate LG&E rate to be $9.04, an increase of more than 75 percent.[835] Finally, LG&E/KU reiterated that the information and calculations presented in this case were consistent with rate calculations since 2014.[836]

In Administrative Case No. 251 the Commission stated the following,

> The Commission recognizes, as recommended by the CATV operators and most of the utilities represented at the proceeding, that the formula should be simple and easily applied. Further, the formula should produce a fair, just and reasonable rate, based on the fully allocated costs of the utility in furnishing pole attachment services.
>
> Ideally, the various cost factors needed to apply the formula should be readily available public information, such as that disclosed in the utility's required annual reports to the Commission or other public agencies. When this is not the case, we find that each utility shall file with its proposed tariffs the source and justification for cost factors used in applying the formula to compute its rate to the CATV operator.
>
> … that the methodology shall be (1) the embedded cost of an average bare pole of the utility of the type and size which is or may be used for the provision of CATV attachment

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833 LG&E/KU's Post-Hearing Brief (filed Dec. 2, 2025) at 30-35.

834 LG&E/KU's Post-Hearing Brief at 35-36; *citing* November 6, 2025 Hearing, 4:58:10 p.m. – 4:59:20 p.m. (discussing Case No. 2014-00372, Direct Testimony of Patricia Kravtin at 6 (Mar. 6, 2015)).

835 LG&E/KU's Post-Hearing Brief at 35-36.

836 LG&E/KU's Post-Hearing Brief at 39-40.

> (2) multiplied by an annual carrying charge, and (3) this product multiplied by the percentage of usable space used fox CATV pole attachments."[837]

Although the Order was issued some time ago, the Commission reiterates that the pole attachment rates should be based on public, transparent information. FERC Form 1 and annual reports' information should be used in the calculation of this rate. With that being said, the Commission must recognize that, since 2014, LG&E/KU has calculated its pole attachment rates as proposed in this Application and the Commission has not commented upon or rejected the methodology, as stated in LG&E/KU's brief.[838]

Having considered the evidence and being other sufficiently advised, the Commission finds that the Rate PSA rates set forth in the Stipulation should be accepted, as modified, as discussed herein, as fair, just and reasonable. KU should be aware that settlements are generally not considered precedential and relying on settlement rate approval would be to its detriment. The Commission should not yank the proverbial rug out from under KU without some notice as to its expectations with regard to the pole attachment calculations, even if the acceptance of the rates in 2014 and the 2016 case were the result of a settlement.

The Commission puts KU on notice that going forward, it should use public information from annual reports and FERC filings. It was evident at the hearing that KU could not explain the origin or basis for certain information used in its calculations.[839] The

[837] Administrative Case No. 251, (Ky. PSC Sept. 7, 1982), Order at 8.

[838] LG&E/KU's Post-Hearing Brief at 36-40.

[839] HVT of Timothy Lyons, Nov. 5, 2025 Hearing at 01:52:51-01:53:20, 01:58:53-01:59:33, 01:59:25-:01:59:33, 01:56:00-01:58:18; HVT of Michael Hornung, Nov. 6, 2025 at 02:30:44-02:31:24.

calculation should be transparent and easily verifiable. It should not require an outside party to reconcile conflicting numbers or guess as to how a number was derived.

Recently, LG&E/KU filed notice of a desire to pursue a merger.[840] The Commission notes that this could potentially eliminate the issue arising from a combined rate for LG&E/KU for pole attachments. The Commission wants to emphasize that LG&E and KU are supposed to be separate entities and until such time as a merger is approved, are to be operated and accounted for as such. Should the companies change plans, the Commission expects LG&E and KU to present separate rates for pole attachments in its next application for a general rate adjustment or specifically an adjustment to Rates PSA. However, in this case, the Commission must balance the utility's reliance on prior Commission Orders with the need to establish fair, just and reasonable rates. Because LG&E/KU anticipate requesting approval of a merger, the Commission believes that balance favors allowing the calculation to remain the status quo.

As to the combined carrying costs, the Commission notes that Administrative Order 251 allows for combined carrying costs, should the utility provide justification for the amount.[841] The Commission has allowed LG&E/KU to use combined costs in this manner in the past. KBCA did not present sufficient evidence to require LG&E/KU to eliminate the combined carrying costs nor did it cite to a change in circumstance or law which would require the Commission to deviate from its administrative Order or prior approvals for these utilities.

[840] LGE&E/KU's Update on Legal Merger (filed Dec. 30, 2025).

[841] Administrative Case No. 251, September 7, 1982 Order at 12.

The rates presented in the Stipulation reflect the stipulation return on equity as well as the cost of long term debt. However, as discussed in this Order, the Commission has modified both items. As such, the rates must be modified to reflect the approved return on equity and cost of long term debt. The Commission agrees that LG&E/KU should be allowed to calculate rates based on the most recent approved return on equity established in this case. The rates set forth in Appendix E are accepted and are fair, just and reasonable.

QUALIFYING FACILITIES

Application and Stipulation

In its application, KU requested updated avoided energy costs for wind, solar, and other technologies, and to update avoided capacity costs as it relates to other technologies in its SQF and LQF tariffs.[842] Regarding avoided capacity for wind and solar, KU recommended a zero avoided value.[843] KU argued if it does not actually avoid costs commensurate with the rates paid to qualifying facilities (QF), then all customers—who pay the costs associated with purchases under these rates in nearly real-time through the FAC as purchased power—will bear the burden of the overpayment.[844] The Commission will discuss these issues further below.

The Stipulation did not specifically address the updated rates for large qualifying facilities (LQF) and small qualifying facilities (SQF), but the updated rates were generally

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[842] Schram Direct Testimony at 34.

[843] Schram Direct Testimony at 35.

[844] KU's Post-Hearing Brief at 26.

agreed to by the Signing Parties in the approval of the tariff sheets and the catch all provision.[845]

Legal Standard

The purpose of 807 KAR 5:054 is described in the regulation as follows:

> Under Title II of the Public Utility Regulatory Policies Act of 1978, the Federal Energy Regulatory Commission (FERC) was required to adopt rules to encourage cogeneration and small power production by requiring electric utilities to sell electricity to qualifying cogeneration and small power production facilities and purchase electricity from such facilities. Section 210(f) of this Act requires the state regulatory authority with jurisdiction over electric utilities to implement the FERC rules. As the state regulatory authority for Kentucky, the Public Service Commission proposes to implement those rules.

In accordance with 807 KAR 5:054, Section 7(2) and (4), the compensation rate for QF's should be just and reasonable to the electric customer of the utility, in the public interest, and nondiscriminatory. In accordance with 807 KAR 5:054, Sections (1) and 7(2) and 7(4), the QF compensation rate should be based on the avoided costs, or the incremental costs, to a utility for electric energy or capacity, or both, that the utility would generate themselves or purchase from another source, if not for the purchase from the qualifying facility.

Commission regulation 807 KAR 5:054 Section 7(5) states:

> Factors affecting rates for purchase for all qualifying facilities. In determining the final purchase rate, the following factors shall be taken into account:
> (a) Availability of capacity or energy from a qualifying facility during the system daily and seasonal peak. The utility should consider for each qualifying facility the ability to dispatch, reliability, terms of contract, duration of obligation, termination requirements, ability to coordinate scheduled

[845] Stipulation, Article 5.2; Amended Stipulation, Article 11.1.

> outages, usefulness of energy and capacity during system emergencies, individual and aggregate value of energy and capacity, and shorter construction lead times associated with cogeneration and small power production.
> (b) Ability of the electric utility to avoid costs due to deferral, cancellation, or downsizing of capacity additions, and reduction of fossil fuel use.
> (c)Savings or costs resulting from line losses that would not have existed in the absence of purchases from a qualifying facility.

Discussion and Findings

Avoided Energy Costs. KU evaluated the impact on system energy costs for each QF technology using forecasted hourly energy costs developed in the PROSYM model.[846] In Case No. 2025-00045,[847] the resource portfolio KU along with LG&E proposed included assumptions for computing hourly energy costs which included the resource-constrained load forecast and were approved.[848] KU stated that, to focus the analysis on the cost of KU's and LG&E's resource serving native load, that market electricity purchases and off-system sales were not permitted in PROSYM.[849] KU explained that avoided energy costs include the cost of fuel, emission control reagents (e.g., limestone, ammonia), emission allowance costs, and an opportunity cost for lost CCR revenues.[850] KU developed a

[846] Schram Direct Testimony, Exhibit CRS-6 at 3 (note this was a joint report for both LG&E and KU).

[847] Case No. 2025-00045, *Electronic Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates.*

[848] Schram Direct Testimony, Exhibit CRS-6 at 3.

[849] Schram Direct Testimony, Exhibit CRS-6 at 3.

[850] Schram Direct Testimony, Exhibit CRS-6 at 3.

generation profile for each QF technology with an assumed nameplate capacity of 80 MW, the maximum nameplate capacity for a QF.[851]

To compute the avoided cost of energy for each generation technology, KU first computed the decremental cost of energy for each megawatt-hour (MWh) of generation in each hour of the forecast period (2026-2033).[852] Then, for each hour and generation technology, the avoided cost of energy was computed with the assumption that the highest-cost energy would be avoided first.[853] To develop QF rates, the annual avoided energy costs were averaged over three fuel price scenarios and then were levelized to provide the final avoided energy prices.[854]

The proposed avoided energy costs are as follows:

Table 4: Avoided Energy Costs ($/MWh)

Technology	2-Year PPA (2026-2027)	7-Year Level Price for PPAs Beginning: 2026	7-Year Level Price for PPAs Beginning: 2027
Solar: Single-Axis Tracking	31.52	36.15	37.35
Solar: Fixed Tilt	31.55	36.23	37.45
Wind	30.62	34.38	35.48
Other Technologies	30.54	34.80	35.95

For the two-year PPA, KU levelized the average annual avoided energy costs for 2026 and 2027.[855] For the seven-year PPA, KU levelized the average avoided energy costs from 2026 to 2033.[856] The average annual avoided costs generally increased each

[851] Schram Direct Testimony, Exhibit CRS-6 at 3.

[852] Schram Direct Testimony, Exhibit CRS-6 at 4.

[853] Schram Direct Testimony, Exhibit CRS-6 at 4.

[854] Schram Direct Testimony, Exhibit CRS-6 at 4-5.

[855] Schram Direct Testimony, Exhibit CSR-6 at 5.

[856] Schram Direct Testimony, Exhibit CSR-6 at 5.

year.[857] KU included line losses in its recommended QF rates.[858] KU assumed 4.748 percent in energy losses and 6.449 percent in capacity losses.[859]

KYSEIA recommended that variable maintenance costs be included in avoided energy costs.[860] KYSEIA explained that PJM Interconnection considers variable operations and maintenance (VOM) costs as including three distinct components – major maintenance, minor maintenance, and operating costs.[861] KYSEIA stated that KU's avoided energy costs exclude the two categories of VOM costs related to maintenance.[862] KYSEIA argued that these are significant as PJM's default values, effective January 1, 2025, minor maintenance costs alone are \$4.43/MWh for a simple-cycle combustion turbine, \$2.11/MWh for a fossil steam turbine, and \$1.21/MWh for a combined cycle unit.[863] Major maintenance costs (i.e., maintenance activities that require unit disassembly, or the replacement or overhaul of major components) are also incurred in addition to minor maintenance costs.[864] KYSEIA recommended to apply PJM's default variable maintenance costs for minor maintenance based on KU's share of generation by technology type, essentially a weighted-average variable minor maintenance cost, and

[857] Schram Direct Testimony, Exhibit CSR-6 at 6.

[858] Schram Direct Testimony at 36.

[859] Schram Direct Testimony, Exhibit CSR-6 at 15.

[860] Hoyle Direct Testimony at 9.

[861] Hoyle Direct Testimony at 7.

[862] Hoyle Direct Testimony at 7.

[863] Hoyle Direct Testimony at 7-8.

[864] Hoyle Direct Testimony at 8.

add that to the avoided energy cost.[865] KYSEIA calculated variable minor maintenance costs for 2026 which resulted in average variable maintenance costs for minor maintenance of $2.08/MWh.[866]

KYSEIA also raised concerns that, because the proposed energy credit has no seasonal or time differentiation, the credit does not provide a price signal to which customers may respond.[867] KYSEIA explained that even a simple price signal, like higher export compensation prices for summer afternoons and winter mornings, has the ability to influence behavior.[868] KYSEIA recommended the Commission consider some basic price differentiation in the energy credit compensation structure.[869]

KU rebutted that, as it is not a member of PJM, PJM's costs and frameworks do not apply.[870] KU stated it is appropriate to exclude maintenance costs from avoided energy costs because distributed generation resources, whether QFs or net metering customers' generators, do not cause KU to avoid any maintenance cost for their generating units.[871]

Having considered the record and being otherwise advised, the Commission finds that the QF energy rates should be approved consistent with the Stipulation. The Commission has previously found that it is reasonable to estimate avoided energy costs

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[865] Hoyle Direct Testimony at 9.

[866] Hoyle Direct Testimony at 9.

[867] Hoyle Direct Testimony at 10.

[868] Hoyle Direct Testimony at 10.

[869] Hoyle Direct Testimony at 10.

[870] Schram Rebuttal Testimony at 5.

[871] Schram Direct Testimony at 5.

from different technologies using forecasted hourly energy costs developed in PROSYM.[872] In its next QF filing, the Commission expects KU to consider including maintenance costs, including variable costs and the ability to coordinate outages as listed in 807 KAR 5:054 Section 7(5). As to KYSEIA's recommendations related to seasonal avoided energy rates, the Commission encourages KU to study seasonal avoided energy rates in its next QF filing. As to avoided line losses, in Case No. 2020-00349, the Commission affirmed that it was necessary to include line losses as part of QF rates where generation is located on the distribution system.[873] The Commission approves KU's calculation of line-losses for distribution-interconnected projects.

Avoided Capacity Costs

To calculate avoided capacity costs, KU used PLEXOS modeling to evaluate each technology's contribution to the timing and size of KU's future need for capacity.[874] KU explained that results showed that 80 MW QF PPAs of single-axis tracking solar, fixed tilt solar, and wind do not result in any changes to KU's optimal resource plan.[875] KU recommended the avoided capacity cost for these three technology types be zero.[876]

KU explained that 80 MW of "other" technologies, which is assumed to be fully dispatchable, results in a decreased amount of MW for the Cane Run BESS in 2028 and recommended an avoided capacity cost for "other" technologies based on Cane Run

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[872] Case No. 2020-00349, Sept. 24, 2021 Order at 29.

[873] Case No.2020-00349, Sept. 24, 2021 Order at 31.

[874] Schram Direct Testimony at 34.

[875] Schram Direct Testimony at 34.

[876] Schram Direct Testimony at 34.

BESS costs.[877] KU explained that because other technologies are assumed to be fully dispatchable, their capacity contribution is assumed to be 100 percent, but the capacity contribution of BESS in the context of KU and LG&E's proposed resource plan in Case No. 2025-00045, was determined to be 83 percent.[878] KU recommended applying an availability factor of 120 percent (100 percent divided by 83 percent) to the capacity cost of the Cane Run BESS to reflect the higher reliability of fully dispatchable resources.[879] This was used to calculate the annual avoided capacity costs based on the cost of Cane Run BESS.[880] To compute avoided capacity costs on a $/MWh basis, the annual values were divided by 8,760 hours.[881]

KU also explained that because KU is transitioning from lower economic minimum reserve margins to higher minimum reserve margins.[882] These margins are developed to reduce the loss of load expectation.[883] The capacity need is assumed to be immediate, in 2026.[884]

In response to Staff's Post-Hearing Request, KU provided updated analysis based on the methodology approved in Case No. 2023-00404, with updated assumptions.[885]

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[877] Schram Direct Testimony at 34.

[878] Schram Direct Testimony at 35.

[879] Schram Direct Testimony at 35.

[880] Schram Direct Testimony, Exhibit CSR-6 at 8.

[881] Schram Direct Testimony, Exhibit CSR-6 at 8.

[882] Schram Direct Testimony at 35.

[883] Schram Direct Testimony at 35.

[884] Schram Direct Testimony at 35.

[885] KU's Response to Staff's Post-Hearing Request, Item 40(d).

KU stated that it updated information to reflect avoided capacity costs based on the cost of Brown 12 in 2030 and scaled by availability factors for QF technology options.[886] KU stated that assumptions for capital and fixed operating costs for Brown 12 in 2030 were consistent with Case No. 2025-00045.[887]

KYSEIA stated that the Cane Run BESS may be a reasonable basis for determining the avoided capacity costs but only with corrections to the methodology.[888] KYSEIA identified two issues with how the avoided capacity cost is determined (1) the nature of the batteries' charge-discharge cycle and the method used to convert the $/MW-year value into a $MWh price; and (2) the lack of seasonally differentiated capacity payments.[889]

KYSEIA argued that requiring a QF to operate at full output in every hour of the year to receive the full capacity payment is highly discriminatory against QFs and unreasonable.[890] KYSEIA stated that avoided cost rates define peak energy hours for peak capacity months and set a capacity payment so a QF operating at full output during all of those hours in those months would receive the full $/MW-year avoided cost capacity payment.[891] KYSEIA stated that KU's methodology to convert $/MW-year capacity values into a $/MWh payment would not allow KU to recover the full capacity costs of the Cane

[886] KU's Response to Staff's Post-Hearing Request, Item 40(d).

[887] KU's Response to Staff's Post-Hearing Request, Item 40(d).

[888] Hoyle Direct Testimony at 12.

[889] Hoyle Direct Testimony at 13.

[890] Hoyle Direct Testimony at 14.

[891] Hoyle Direct Testimony at 14.

Run BESS if KU were compensated for that unit under the methodology they propose for QFs, and does not reflect the non-dispatchable nature of BESS.[892]

KYSEIA also recommended that, instead of offering the capacity payment in all months as KU proposed, a more effective price signal to encourage QFs and Rider NMS-2 customers to provide KU capacity, would be to offer the capacity payment during winter and summer months.[893]

KYSEIA argued that the proposals concerning capacity rates are not fair, just and reasonable and should be denied.[894] KYSEIA argued that KU has a current capacity need, and QFs who supply KU with capacity are required to be compensated when they supply it.[895] KYSEIA stated that KU's justification for the zero dollar capacity value for wind and solar is unsupported by KU's own statements that solar technologies have a capacity contribution of 84 percent in summer and wind technologies have a capacity contribution of 11 percent and 35 percent in summer and winter, respectively.[896] KYSEIA stated that a capacity credit should be included whenever KU has identified a future capacity need, regardless of whether it has a plan to meet that need or whether KU's resource plan doesn't fulfill the future need.[897] KYSEIA emphasized that the

[892] Hoyle Direct Testimony at 14.

[893] Hoyle Direct Testimony at 15-16.

[894] KYSEIA's Post-Hearing Brief at 5.

[895] KYSEIA's Post-Hearing Brief at 5.

[896] Hoyle Direct Testimony at 17.

[897] Hoyle Direct Testimony at 20.

determination of whether to include avoided capacity cost compensation is not dependent on a single QF project altering the results of a planning model.[898]

KYSEIA stated that the proposed pricing structure for capacity compensation is completely unrelated to the seasonality and timing of peak loads, provides no price signal to influence market participants' decisions, and likely provides a price signal that would discourage market participants from options to increase their capacity contributions during peak load times.[899] KYSEIA stated the avoided cost components for transmission capacity, distribution capacity, and ancillary services should be included in the Rider SQF.[900] KYSEIA recommended KU clarify the circumstances under which they propose a solar or wind QF or Rider NMS-2 customer-generator would be compensated based on the "Other" QF technology type and adjust the QF tariffs and Rider NMS-2 rates accordingly.[901]

KU rebutted stating that it does not have seasonal or peak avoided capacity costs; it does not participate in RTOs' seasonal capacity auctions, for example; costs associated with capacity are the same in all hours.[902] KU also stated that the Commission's QF regulation clearly states that a utility's avoided costs, not what would make QF owners whole, are the appropriate and sole basis for setting QF capacity rates.[903] KU also

[898] Hoyle Direct Testimony at 23.

[899] Hoyle Direct Testimony at 23.

[900] Hoyle Direct Testimony at 5.

[901] Hoyle Direct Testimony at 19.

[902] Schram Rebuttal Testimony at 6.

[903] Hornung Rebuttal Testimony at 18.

disagreed with KYSEIA's recommendations regarding transmission capacity, distribution capacity, and ancillary services costs in KU's Rider SQF.[904]

KU highlighted that the small capacity need is temporary and that in 2027, there is a summer surplus of 364 MW and a winter shortfall of just 22 MW (relative to a 1-in-10 loss of load expectation-based reserve margin) and re-highlighted its modeling of its resource plans.[905]

Having considered the record and being otherwise sufficiently advised, the Commission finds that KU's avoided capacity cost, as it relates to solar and wind, is unreasonable and therefore is denied. KU stated that it has an immediate capacity need, as pointed out by KYSEIA. In Case No. 2023-00404, the Commission noted that there are unique conditions applicable to a utility's system which may preclude the necessity for capacity payments.[906] The Commission addressed these scenarios in Administrative Case 8566 finding that:

> If a utility demonstrates to the commission's satisfaction that it simultaneously faces insignificant load growth, excess capacity, minimum off system sales and is neither planning nor constructing capacity within its ten-year planning horizon then the utility cannot avoid capacity-related costs at that time so a capacity payment would not be justified.[907]

[904] Hornung Rebuttal Testimony at 17.

[905] Schram Rebuttal Testimony at 6.

[906] Case No. 2023-00404, *Electronic Tariff Filings of Louisville Gas and Electric Company and Kentucky Utilities Company to Revise Purchase Rates for Small Capacity and Large Capacity Cogeneration and Power Production Qualifying Facilities and Net Metering Service-2 Credit Rates* (Ky. PSC Aug. 30, 2024), Order at 19.

[907] Administrative Case No. 8566, Re Small Power Producers and Cogenerators, Order June 28, 1984 Order at 5.

In Case No. 2023-00404, the Commission noted that the applicant utility bears the burden to demonstrate the reasonableness of zero avoided capacity costs.[908] Likewise, the Federal Energy Regulatory Commission (FERC) found that "[when capacity is not needed, the avoided capacity cost rate can be zero.]"[909] In this case, KU has shown that there is a clear and immediate capacity need starting in 2026. Furthermore, as the Commission determined in Case No. 2025-00045, there is a likelihood of significant expected load growth, and the Commission has approved several planned generation projects in the next ten years. Therefore, KU has not met its burden of proof to demonstrate a zero avoided capacity cost.

The Commission finds that the appropriate avoided capacity cost analysis should be based on the cost of Brown 12 as described above, as avoided capacity costs are based on the type of generating facilities that the utility is planning for, currently procuring, or constructing. In Case 2020-00349, the Commission adopted the use of a simple cycle CT as the proxy for avoided generation capacity.[910] The Commission also acknowledged that another resource may become a more suitable proxy for valuing capacity in the future.[911] In Case No. 2023-00404, the Commission noted that it is appropriate to utilize a natural gas combined cycle (NGCC) for capacity values and costs considering the capacity values should reflect the actual resource generation that KU and LG&E is

[908] Case No. 2023-00404, Aug. 30, 2024 Order at 20.

[909] Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, Order No. 872A, 173 FERC paragraph 61,158, 61,955 (2020).

[910] Case No. 2020-00349, Sept. 24, 2021 Order at 24.

[911] Case No. 2020-00349, Sept. 24, 2021 Order at 34.

constructing/planning to meet their capacity needs.[912] Therefore the Commission finds the following avoided capacity rates to be reasonable:

	QF Avoided Capacity (without line losses for transmission connected projects)		
	2-Year PPA	2026	2027
Solar: Single-Axis Tracking	$34.27	$35.40	$35.90
Solar: Fixed Tilt	$32.81	$33.89	$34.37
Wind	$17.24	$17.81	$18.07
Other	$19.55	$20.19	$20.48
	QF All-In Avoided Capacity (with line losses)		
	2-Year PPA	2026	2027
Solar: Single-Axis Tracking	$36.48	$37.68	$38.22
Solar: Fixed Tilt	$34.92	$36.07	$36.59
Wind	$18.36	$18.96	$19.23
Other	$20.81	$21.49	$21.80

Availability

KU proposed changes to the availability section of both its SQF and LQF tariffs to state that "Seller may enter into a PPA with Company only if Seller simultaneously sells the entire output of Seller's qualifying facility to Company while purchasing all of Seller's own requirements from Company."[913] Under this, Seller may choose either to enter into a PPA with Company for sales of energy and capacity from Seller or to sell only energy to Company as an as-available basis.[914]

KYSEIA stated that the proposed changes to the terms of Rider SQF and Rider LQF prevent QFs that supply their own behind the meter (BTM) load from entering into

[912] Case No. 2023-00404, Aug. 30, 2024 Order at 21.

[913] Application, Tab 5 at 106, P.S.C. No. 21, Original Sheet No. 55 and at 110 P.S.C. No. 21, Original Sheet No. 56.

[914] Application, Tab 5 at 106, P.S.C. No. 21, Original Sheet No. 55 and at 110 P.S.C. No. 21, Original Sheet No. 56.

PPAs, and without a PPA, QFs with a BTM load are not eligible to receive the fixed long-term price offered only under a 7-year PPA nor are they eligible for capacity payments.[915] KYSEIA argued that there is no basis in 807 KAR 5:054 for discriminating against QFs that supply some or all of their own power needs and only make available for purchase by the utility a portion of the QF output; likewise there is no carve-out or exception that limits the utility obligation to purchase both energy and capacity to only those QFs who agree to sell all the facility's output to the utility and agree to purchase all the power the facility requires from the utility.[916] KYSEIA explained that under KU's proposed changes to the QF Tariffs, if a QF exercises its option under 807 KAR 5:054 Section 7(1)(a) to power its BTM load and sell its surplus output to the utility, that QF is forced to accept the as-available utility purchase rates and is denied its choice of the rate options under 807 KAR 5:054 Section 7(2)(b) for Rider SQF and 807 KAR 5:054 Section 7(4)(b) for Rider LQF.[917]

KYSEIA also explained that KU's proposal, eliminating PPAs completely for some QFs, would increase some QF developers' exposure to price risk, undermine some QF developers' ability to obtain financing, and impose an unreasonable imbalance of risk that heavily favored the utilities while increasing the risks allocated to QF ratepayers and developers.[918] KYSEIA argued that KU's efforts to deny QFs access to contractual terms are not only unreasonably prejudicial against QF developers but are also contradictory to

[915] Hoyle Direct Testimony at 25.

[916] Hoyle Direct Testimony at 25-26.

[917] Hoyle Direct Testimony at 27-28.

[918] Hoyle Direct Testimony at 30.

the utility obligations in multiple sections of 807 KAR 5:054 and render the Commission's authority to review and approve such contracts meaningless.[919] KYSEIA recommended that all QFs, including BTM QFs, should be required to enter into a PPA that establishes the terms under which they sell power to KU and that the PPA should be effective for a number of years sufficient to provide QF's certainty regarding contractual terms necessary for business planning and financing.[920]

KU rebutted stating it would serve no purpose to have PPAs for BTM QFs, as a BTM QF can only provide as-available energy.[921] KU also stated that not providing capacity compensation to BTM QFs is consistent with and symmetrical to the Commission's position that KU cannot provide Green Tariff customers demand charge credits and the operation of the solar share program.[922] KU also explained that any resource that might not be fully available—or available at all—because another party has the first right to use it is not a resource the Companies can reasonably include in their resource planning.[923]

KU stated that is not reasonable to separate QF PPA contract duration from pricing duration, as this is not something the Commission's QF regulation allows or contemplates.[924] KU stated it was willing to entertain longer-term PPAs for buy-all, sell-

[919] Hoyle Direct Testimony at 31.

[920] Hoyle Direct Testimony at 34.

[921] Hornung Rebuttal Testimony at 15.

[922] Hornung Rebuttal Testimony at 16.

[923] Schram Rebuttal Testimony at 7.

[924] Hornung Rebuttal Testimony at 17.

all QFs on a case-by case basis, which is appropriate and permissible under the Commission's QF regulation.[925]

Commission regulation 807 KAR 5:054 Section (6) requires each electric utility to purchase any energy and capacity which is made available from a qualifying facility subject to exceptions related to system emergencies and when purchases from qualifying facilities will result in costs greater than those which the utility would incur if it generated an equivalent amount of energy instead of purchasing that energy.

Likewise, all QFs have the option to "(a) Use output of the qualifying facility to supply their power requirements and selling their surplus; or (b) Simultaneously selling their entire output to the interconnecting utility while purchasing their own requirements from that utility."[926] SQFs have the option for rates for power offered on an "as available basis" or rates for power offered on all legally enforceable obligations.[927] Likewise, LQFs have the option of rates for power offered on an as available basis or rates for energy or capacity or both offered on a legally enforceable basis.[928]

Having considered the record and being otherwise sufficiently advised, the Commission finds that KU's proposed tariff revision should be denied. While the Commission agrees with KU that BTM customers would likely only be able to provide as-available energy, there may be instances where BTM customers are able to commit part of their capacity to KU, and therefore qualify for rates based on legally enforceable

[925] Hornung Rebuttal Testimony at 17.

[926] 807 KAR 5:054 Section 7(1).

[927] 807 KAR 5:054 Section 7(2).

[928] 807 KAR 5:054 Section 7(4).

obligations. The Commission does not find a utility's categorical refusal to agree to enter into PPAs unless a QF enters a buy-all sell- all agreement reasonable. The FERC has made it clear that

> A QF has the option to commit itself to sell all or part of its electric output to an electric utility. While this may be done through a contract, if the electric utility refuses to sign a contract, the QF may seek state regulatory authority assistance to enforce the PURPA-imposed obligation on the electric utility to purchase from the QF, and a non-contractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA.[34] Accordingly, a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.[929]

Therefore, the Commission finds that a QF has the option to commit part of its electric output to an electric utility and that it is reasonable to allow those QFs to enter into a PPA.

<u>Co-Located Residential Battery Energy Storage Systems</u>

KYSEIA recommended that KU include battery-coupled distributed generation (DG) resources into their Rider NMS-2 and QF Tariffs, with appropriate price signals, and also recommended the Commission consider the resilience benefits offered by these systems to all ratepayers in its evaluation of a just and reasonable compensation rate for net metering exports.[930] KYSEIA explained that small-scale battery systems coupled with DG can turn every rooftop participating in net metering into a dispatchable capacity resource at any time of the day on any day of the year – if provided an appropriate price

[929] *JD Wind 1, LLC JD Wind 2, LLC JD Wind 3, LLC JD Wind 4, LLC JD Wind 5 LLC JD Wind 6, LLC*, 129 FERC ¶ 61,148, 61,633 (2009).

[930] Hoyle Direct Testimony at 56.

signal by reasonable rate design.[931] KYSEIA stated that batteries coupled with DG also promote disaster resilience and self-reliance in all the communities where they are located.[932]

KU rebutted that it would not be appropriate for it to treat solar or wind distributed generators paired with BESS as an "other" QF technology type.[933] KU explained that unless a solar or wind QF resource had a significant amount of energy associated with it, it would be unlikely to be fully dispatchable in all hours.[934] KU also stated that, without KU having the ability to monitor and control the BESS, which is not a condition of the KU's QF tariff provisions, it would be inappropriate to assume for planning purposes that a QF's BESS would be charged and dispatchable to meet KU's needs.[935] KU explained that it could work with a solar or wind plus BESS QF to arrive at appropriate compensation for allowing the Companies to monitor and control the QF's BESS; it is not a concept KU opposes.[936]

Having considered the record and being otherwise sufficiently advised, the Commission agrees with KYSEIA's recommendation that KU should clarify the circumstances under which a solar or wind QF customer-generator with a co-located or coupled battery energy storage system would be compensated based on the "Other" QF technology type. The Commission finds that KU should clarify these circumstances in its

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[931] Hoyle Direct Testimony at 55.

[932] Hoyle Direct Testimony at 55.

[933] Schram Rebuttal Testimony at 8.

[934] Schram Rebuttal Testimony at 8.

[935] Schram Rebuttal Testimony at 8.

[936] Schram Rebuttal Testimony at 9.

next QF proceeding. When solar or wind generation is coupled with a battery, this technology configuration increases both when and how the renewable generation can be dispatched and thus can be used to help reduce peak demand for the utility. Therefore, renewable technology when paired with batteries could qualify under the "Other" QF technology and be eligible for capacity payments contingent upon the customer committing a portion of its QF to KU.

NET METERING

In Case No. 2019-00256,[937] the Commission opened an administrative case to discuss the implementation of net metering for all electric utilities. The Order stated that the proceedings for the implementation of net metering rates should be thorough and transparent.[938] In that Order, the Commission noted that net metering ratemaking processes should consider utility specific costs, and not a uniform rate for all electric utilities.[939]

Subsequently, the Commission issued Orders in both LG&E and KU's initial net metering cases,[940] Kentucky Power Company's (Kentucky Power) initial net metering case[941]; and Duke Energy Kentucky's (Duke Kentucky) initial net metering case.[942] In the

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[937] Case No. 2019-00256, *Electronic Consideration of the Implementation of the Net Metering Act* (Ky PSC Dec. 18, 2019).

[938] Case No. 2019-00256, Dec. 18, 2019 Order at 31.

[939] Case No. 2019-00256, Dec. 18, 2019 Order at 32.

[940] Case No. 2020-00349, Sept. 24, 2021 Order; Case No. 2020-00350, Sept. 24, 2021 Order.

[941] 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 May 14, 2021).

[942] Case No. 2023-00413, *Electronic Application of Duke Energy Kentucky, Inc. for an Adjustment to Rider NM Rates and for Tariff Approval* (filed Dec. 20, 2023).

Kentucky Power final Order, the Commission outlined several principles that utilities should consider when determining their net metering rates and proposals.[943] Specifically, those principles are to: evaluate eligible generating facilities as a utility system or supply side resource; treat benefits and costs symmetrically; conduct forward-looking, long-term, and incremental analyses; avoid double counting; and ensure transparency.[944] The Commission also noted that, when considering rate designs for either export or consumption, "it is important to consider the above principles alongside the additional principles of stability and simplicity."[945]

In Case No. 2023-00404, LG&E and KU jointly requested to change their net-metering-2 (NMS-2) rates. In that case, the Commission set KU's current NMS-2 rates at $0.07534 per kWh.[946] The following chart reflects KU's current bill credit for excess generation:[947]

KU NMS-2 Bill Credit	
Energy*	$0.03256
Ancillary Services	$0.00084
Generation Capacity*	$0.01542
Transmission Capacity	$0.00732
Distribution Capacity	$0.00185
Carbon Cost	$0.01338

[943] Case No. 2020-00174, May 14, 2021 Order at 21-24.

[944] Case No. 2020-00174, May 14, 2021 Order at 21-24.

[945] Case No. 2020-00174, May 14, 2021 Order at 24.

[946] Case No. 2023-00404, *Electronic Tariff Filings of Louisville Gas and Electric Company and Kentucky Utilities Company to Revise Purchase Rates for Small Capacity and Large Capacity Cogeneration and Power Production Qualifying Facilities and Net Metering Service-2 Credit Rates* (Ky. PSC Aug. 30, 2024), Order, Appendix A. Note that this case addressed both LG&E and KU's NM-2 rates. For purposes of this Order, only KU rates will be discussed.

[947] Case No. 2023-00404, LG&E/KU's Response to Commission Staff's First Request for Information, Item 5 (filed Jan. 25, 2024).

Environmental Compliance Cost	$0.00397
Jobs Benefit	-
NSM-2 Bill Credit For Excess Generation	$0.07534
*With losses	

The Commission found in that case that KU should incorporate the arguments raised by the Joint Intervenors in the record regarding updating the other components of the bill credits, and file additional evidence and testimony in its next base rate case.[948]

Application and Stipulation Summary. In its application, KU requested to revise its NMS-2 rates to an energy-only avoided cost of $0.03859 per kWh.[949] The Stipulation stated that KU, as well as LG&E, agreed they will not close their NMS-2 rates to new participants earlier than the effective date of new rates resulting from their next base rate cases.[950] The Stipulation also stated that that KU will leave the NMS-2 rates at their current level and these rates are the product of negotiation and are not calculated using any particular methodology.[951] KYSEIA and the Joint Intervenors also presented several recommendations related to NM-2 that will be further discussed below.

KU's Brief. KU argued that the Commission should use the sum of the energy, generation capacity, carbon, ancillary services, and environmental compliance costs distributed solar energy purports to avoid cannot exceed the cost of utility-scale solar energy adjusted for line losses.[952] KU stated that, in these cases, no party has contested

[948] Case No. 2023-00404, Aug. 30, 2024 Order at 24.

[949] Hornung Direct Testimony at 18.

[950] Stipulation, Section 9.13.

[951] Stipulation, Section 9.13.

[952] KU's Post-Hearing Brief at 28.

that KU's Mercer County Solar pricing ($0.06736 per kWh), which serves as the maximum customers should have to pay, adjusted for line losses, for the sum of the five potential avoided cost components listed above.[953] KU also stated that it is and has always been KU's intention to comply with all lawful Commission Orders, and any assertion to the contrary concerning KU's approach to NMS-2 rates in these cases is simply false.[954] KU argued that the Commission's prior orders on these matters neither prescribed the methodologies KU had to use in proposing updated avoided cost components, nor did they purport to prohibit KU from using other methodologies to propose such updates.[955] KU also asked that if the Commission desires to prescribe certain calculation methodologies in these cases, for the Commission to provide native-format workpapers with all formulas intact so KU may use them in future cases.[956]

Joint Intervenors' Brief. Joint Intervenors first highlighted the value of distributed energy resources (DER), such as rooftop solar, including for each of the categories of avoided costs, as well as a value to the system as a whole if comprehensively integrated into planning and operational processes.[957] Joint Intervenors argued that KU did not follow the Commission's previous Orders with regard to setting the avoided cost components that make up the compensation to customer generators for excess electricity fed back to the grid over a billing period.[958] Joint Intervenors also argued that KU still did

[953] KU's Post-Hearing Brief at 28.

[954] KU's Post-Hearing Brief at 28.

[955] KU's Post-Hearing Brief at 28.

[956] KU's Post-Hearing Brief at 29.

[957] Joint Intervenors' Post-Hearing Brief at 43-44.

[958] Joint Intervenors' Post-Hearing Brief at 44.

not follow the Commission Order on netting methodology.[959] Joint Intervenors also stated that the Stipulation reasonably preserves the status quo for the moment, but the Commission should order short-term compliance with its previous orders.[960] Joint Intervenors also stated that the Commission should direct KU to study how distributed generation (DG) and DERs could be better integrated into their system to produce an even greater value.[961]

KYSEIA Brief. KYSEIA noted that the Stipulation was consistent with its recommendation regarding no changes to NM-2 compensation rates.[962] KYSEIA argued that the rates should remain the same because KU did not provide justification for the reasonableness of its proposals.[963] KYSEIA asserted that KU should address the flaws and shortcomings of their avoided cost analysis when proposing new NMS-2 export rates.[964] KYSEIA also argued that the Commission should expressly order that for the duration of the stay-out period that base rates should also apply to NMS-2 rates so that the effective date of new NMS-2 rates will match the effective date of new rates resulting from KU's next base rate cases, as this appears to be an ambiguity in the Stipulation.[965] KYSEIA agreed that KU should not close its NMS-2 rates and stated that such a provision

[959] Joint Intervenors' Post-Hearing Brief at 46.

[960] Joint Intervenors' Post-Hearing Brief at 48.

[961] Joint Intervenors' Post-Hearing Brief at 49.

[962] KYSEIA's Post-Hearing Brief at 26.

[963] KYSEIA's Post-Hearing Brief at 26.

[964] KYSEIA's Post-Hearing Brief at 27.

[965] KYSEIA's Post-Hearing Brief at 27.

is lawful.[966] KYSEIA argued that its remaining NMS-2 arguments are not ripe for decision in or, alternatively, unnecessary for this proceeding.[967]

No other parties to the proceedings presented arguments on NMS-2.

Discussion and Findings. Having considered the record and being otherwise sufficiently advised, the Commission finds that, consistent with the Stipulation, the NMS-2 rates should remain at its current level. While Joint Intervenors and KYSEIA were not part of the Stipulation, they agreed that this was appropriate.[968] However, for the reasons discussed below, the Commission finds that KU should follow the Commission's previously approved methodologies when setting avoided cost rates. The Commission also finds that, KU should file updated avoided cost components for NMS-2 along with its next QF filing.

Avoided Energy Cost. KU recommended using the average of the 7-year PPA SQF and LQF for the starting years of 2026 and 2027 avoided energy rates for that technology as the avoided energy component of NMS-2 compensation for customers that supply excess energy to the grid.[969] KU's recommendation results in an avoided energy cost of $0.03859 per kWh.[970]

Joint Intervenors stated that use of a 7-year PPA differs substantially from the industry standard of 20 to 30-year agreements for other generators investing in capital-

[966] KYSEIA's Post-Hearing Brief at 27.

[967] KYSEIA's Post-Hearing Brief at 28.

[968] Joint Intervenors' Post-Hearing Brief at 48; KYSEIA's Post-Hearing Brief at 26.

[969] Schram Direct Testimony at 36.

[970] Hornung Direct Testimony at 18.

intensive resources.[971] Joint Intervenors also proposed that KU expand the analysis of price uncertainty and estimate fuel price hedge avoided cost values.[972] Joint Intervenors explained that fossil fuel prices tend to be more volatile than renewable energy sources, and this volatility increases risks to ratepayers who reduce their investment in other productive goods and services in response to higher risk.[973] Despite their argument that KU should use a 20-year PPA, Joint Intervenors calculated a $0.03684 per kWh avoided energy cost.[974]

No other intervenors discussed avoided energy costs as related to net-metering.

As noted above, the Commission finds that the avoided energy rate should remain at their current levels consistent with the Stipulation. The Commission finds that KU's methodology of using the average of the starting years of 2026 and 2027 seven-year PPA is a reasonable methodology and consistent with what the Commission approved in Case No. 2020-00349[975] and expects KU to use a similar methodology in future net-metering cases.

<u>Avoided Generation Capacity Cost.</u> KU proposed that, consistent with the SQF and LQF rates for fixed tilt solar, the avoided capacity component of NMS-2 compensation should be zero.[976] While KU noted an immediate capacity need in 2026,[977] as noted

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[971] Fine Direct Testimony at 16.

[972] Fine Direct Testimony at 18.

[973] Fine Direct Testimony at 17.

[974] Fine Direct Testimony at 16.

[975] Case No. 2020-00349, Sept. 24, 2021 Order at 48-50.

[976] Schram Direct Testimony at 36.

[977] Schram Direct Testimony at 35.

above, for the fixed-tilt solar, KU argued that because 80 MW QFs have no impact on LG&E/KU's optimal resource plan, the avoided capacity cost of these technologies should be zero.[978]

In response to Staff's Fourth Request, KU provided that, if it were to use the methodologies approved by the Commission, the avoided generation capacity cost would be $0.01665 per kWh.[979] KU stated that it used the Brown 12 generating unit, KU's next planned natural gas combined cycle (NGCC), for avoided capacity scaled by an availability factor for fixed tilt solar resources.[980]

Joint Intervenors highlighted the Commission's precedent that "[t]he applicant utility bears the burden to demonstrate the reasonableness of zero avoided capacity costs."[981] Joint Intervenors highlighted that LG&E/KU integrated resource planning (IRP) data for the last 43 years (through 2023) indicate that distributed photovoltaics (DPV) production output coincides with system metered peaks for most of the years.[982] Joint Intervenors originally calculated a $0.02322 per kWh value for avoided generation capacity costs.[983] Joint Intervenors calculated the Net Cost of New Entry (Net Cone) using KU's reported values.[984] Joint Intervenors calculation discounted avoided capacity cost by DPV's Effective Load Carrying Capacity (ELCC, 54 percent), reflected net present

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[978] Schram Direct Testimony at 35.

[979] KU's Response to Staff's Fourth Request, Item 13b.

[980] KU's Response to Staff's Fourth Request, Item 13b.

[981] Fine Direct Testimony at 20 *citing* Case No. 2023-00404, Aug. 30, 2024 Order at 20-21.

[982] Fine Direct Testimony at 20.v

[983] Fine Direct Testimony at 15.

[984] Fine Direct Testimony at 23.

value using LG&E/KU's weighted cost of capital, discounted again for fixed tilt solar capacity factor (15.5 percent), and then divided by solar generation (kWh/yr).[985] Joint Intervenors stated he determined the ELCC using the NREL PV Watts calculated average output during system peak hours in August for Louisville was 54 percent.[986]

KYSEIA argued that avoided generation capacity costs are, in fact, avoidable, by DG resources.[987]

No other intervenors specifically discussed avoided generation capacity cost.

Having considered the record and being otherwise sufficiently advised, the Commission finds that the avoided generation capacity cost should remain at the current rates, consistent with the Stipulation. The Commission also finds that LG&E/KU has not met its burden of proof that the avoided capacity cost should be a zero value, as LG&E/KU has demonstrated an immediate capacity need. In future NMS-2 cases in which KU has a demonstrated capacity need, KU should follow methodologies similar to those approved in Case No. 2020-00349 and 2023-00404, and as calculated in Staff's Fourth Request.[988] Furthermore, in KU's next net-metering case, the Commission finds that KU should report on how DER has been integrated into LG&E/KU's system, an update on LG&E/KU's experience with emerging technologies, and how other jurisdictions are handling an avoided generation capacity charge.

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[985] Fine Direct Testimony at 23.

[986] Fine Direct Testimony at 23-24.

[987] Hoyle Direct Testimony at 41.

[988] Case No. 2020-00349, Sept. 24, 2021 Order at 50.

Avoided Ancillary Service Cost. KU stated that the appropriate value for the avoided ancillary service cost component of Rider NMS-2 compensation rate is zero.[989] KU explained that its Open Access Transmission Tariff (OATT) includes seven ancillary services, each with its own tariffed rate.[990] KU stated that an argument can be made for three of those seven that the costs related to Schedule 3: Regulation Frequency Response (Schedule 3), Schedule 5: Spinning Reserve Service (Schedule 5), and Schedule 6: Operating Reserve Service (Schedule 6) could be avoided if generation capacity costs are deemed to be avoidable.[991] In the LG&E/KU's Open Access OATT approved by FERC, these three ancillary service rates are calculated as a specified percentage of KUKU's fixed generation capacity costs.[992] KU concluded that customer-generators providing excess energy under NMS-2 do not avoid any generation capacity cost, therefore the avoided cost related to these three ancillary services is also zero.[993]

KU explained that, using the methodology approved in Case No. 2020-00349, the ancillary services avoided cost has been estimated at 4 percent of the avoided generation capacity cost. This assumption is derived from the cumulative percentages embedded within three ancillary service rate schedules included in LG&E/KU's OATT, as approved by the FERC.[994] These schedules apply the following percentages to KU's fixed generation capacity costs: Schedule 3 at 1.0 percent, Schedule 5 at 1.5 percent, and

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[989] Schram Direct Testimony at 36.

[990] Schram Direct Testimony at 36-37.

[991] Schram Direct Testimony at 38.

[992] Schram Direct Testimony at 38.

[993] Schram Direct Testimony at 38.

[994] KU's Response to Staff's Fourth Request, Item 13(a).

Schedule 6 at 1.5 percent.[995] Using the methodologies previously approved by the Commission, KU calculated that an estimated Ancillary Services Avoided Cost is $0.00067 per kWh.[996]

Joint Intervenors cited Case No. 2020-00349 and stated that the Commission established a benchmark of $0.00084 per kWh for KU.[997] Joint Intervenors stated that DPV reduces peak loads without requiring additional reserve margins and without line losses, thereby reducing the need for ancillary services.[998] Joint Intervenors argued that in the absence of additional analysis, KU should use the benchmark value inflated to present day.[999] Joint Intervenors argued that the avoided ancillary service cost for KU should be $0.001045 per kwh.[1000]

KYSEIA noted the amount and extent of the avoidable ancillary services costs would be increased substantially for net metering or DG systems coupled or co-located with battery storage, but that KU's proposal is silent on customer-located battery systems.[1001]

KU rebutted that, because BESS cannot qualify for net metering, and Rider NMS-2 doesn't give KU the ability to control NMS-2 customers, the ancillary services

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[995] KU's Response to Staff's Fourth Request, Item 13(a).

[996] KU's Response to Staff's Fourth Request, Item 13(a).

[997] Fine Direct Testimony at 31.

[998] Fine Direct Testimony at 31.

[999] Fine Direct Testimony at 31.

[1000] Fine Direct Testimony at 32.

[1001] Hoyle Direct Testimony at 41.

component is zero.[1002] KU stated that having such control might plausibly allow KU to obtain avoided ancillary services cost benefits; without it, such benefits simply are not possible to obtain.[1003]

Having considered the record and being otherwise sufficiently advised, the Commission finds, consistent with the Stipulation, that the avoided generation capacity cost should remain consistent with the current rates. As noted above, the Commission in Case No. 2020-00349 approved the methodology that calculated ancillary service rates as a percentage of KU's fixed generation costs.[1004] In the next net-metering rate case, the Commission expects KU to use a similar methodology to that approved in Case No. 2020-00349 as it related to avoided ancillary services cost.[1005]

Avoided Carbon Cost. KU stated that the appropriate value for the avoided carbon cost component of the Rider NMS-2 compensation rate is zero.[1006] KU argued that, because there is currently no carbon price for KU's carbon emissions—and the recently finalized federal greenhouse gas regulations applicable to KU's operations would not create a carbon price— Rider NMS-2 customers' energy exports avoid zero carbon cost.[1007]

For avoided carbon costs, Joint Intervenors averaged the cost of carbon capture and storage for natural gas and coal generation ($126/ton), which converts to $0.067 per

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[1002] Schram Rebuttal Testimony at 11.

[1003] Schram Rebuttal Testimony at 11.

[1004] Case No. 2020-00349, Sept. 23, 2021 Order at 55.

[1005] Case No. 2020-00349, Sept. 23, 2021 Order at 55.

[1006] Schram Direct Testimony at 38.

[1007] Schram Direct Testimony at 38.

kWh using a natural gas generator heat rate of 10,000 Btu/kWh.[1008] Joint Intervenors stated that this is found to be a conservative estimate when compared to formulas using the U.S. Environmental Protection Agency (EPA) estimates for the social costs of carbon pollution.[1009]

KYSEIA stated federal regulations would create avoidable costs if KU elected to limit the capacity factor of new gas fired generation, especially combined cycle units, because limiting the capacity factor of a baseload-type generating unit would reduce its energy output and KU's recovery of the unit's fixed costs would then be spread over a smaller number of kWh, increasing the total cost per kWh generated.[1010] KYSEIA argued that such costs could be reduced by accelerated deployment of DG resources that enabled downsizing of a new natural gas-fired generating unit and compensation for DG resources co-located with batteries would support further reductions in new natural gas capacity.[1011]

KU rebutted that there is no cost of carbon to avoid, and there has not been such a cost since Rider NMS-2 rates first took effect in 2021, and there is none plausibly on the near-term horizon, certainly during the current presidential administration.[1012]

Having considered the record and being otherwise sufficiently advised, the Commission finds that the avoided carbon cost should remain at its current rates, consistent with the provisions of the Stipulation. The Commission notes KU has not

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[1008] Fine Direct Testimony at 35.

[1009] Fine Direct Testimony at 35.

[1010] Hoyle Direct Testimony at 52.

[1011] Hoyle Direct Testimony at 52.

[1012] Schram Rebuttal Testimony at 13.

updated its avoided carbon costs since Case No. 2020-00349. In Case No. 2023-00404, KU only updated its energy and capacity values noting that updating the other components would require significantly more data and evaluation, which could be better and more comprehensively addressed in rate case proceedings.[1013] The Commission expects KU to calculate any avoided carbon values consistent with current federal regulations.

Avoided Environmental Compliance Cost. KU argued that the appropriate value of the avoided environmental compliance cost component of the Rider NMS-2 compensation rate is zero.[1014] KU stated that based on how it recommended calculating avoided energy and capacity costs, there is no need for a separate avoided environmental compliance cost component of NMS-2 compensation. KU explained that variable environmental compliance costs, i.e., those that vary with energy production, are already accounted for in the avoided energy cost calculations, any avoided costs driven by environmental regulatory changes that affect generation capacity decisions are already reflected in the avoided generation capacity cost component, and compliance costs reflected in capital improvements at a unit (e.g., installing a selective catalytic reduction system) would be unaffected by energy exported to the grid by a customer-generator.[1015]

When KU was asked to provide a calculation for avoided environmental costs consistent with the methodology laid out in Case No. 2020-00349, KU noted that it is willing to respond to this request, but it cannot do so because the Commission did not

[1013] Case No. 2023-00404, *Kentucky Utilities Company Tariff Filing and Motion for Confidential Treatment, Qualifying Facilities Rates & Net Metering Service-2 Bill Credit* (filed Dec. 4, 2023) at 17.

[1014] Schram Direct Testimony at 38.

[1015] Schram Direct Testimony at 39.

disclose its calculations of an avoided environmental compliance cost in the Company's 2020 base rate case.

Joint Intervenors argued that avoided environmental compliance costs are separate from generation costs because there are really two types of costs associated with power plant emissions: (a) social costs of pollution, including morbidity and mortality caused by coal-source particulate pollution and the effects of climate change, and (b) regulatory responsibilities to mitigate potential harms to human health and the environment.[1016] Joint Intervenors highlighted that environmental mitigation costs can be identified, and highlighted the selective catalytic reduction (SCR) planned for the Ghent 2 coal unit.[1017] Joint Intervenors also highlighted that KU continues to bear significant regulatory risk by relying on coal-powered generation.[1018] Joint Intervenors recommended an avoided environmental compliance cost of $0.0051 per kWh.[1019] Joint Intervenors stated that based on the assumption that Ghent 2 continues to produce approximately 2,700 GWh/Year for 20 years, it would have a lifetime production of 54,000 GWh at a cost of $0.0051 per kWh when discounted using KU weighted average cost of capital (6.56 percent).[1020]

No other intervenor provided testimony specific to environmental compliance costs.

[1016] Fine Direct Testimony at 32.

[1017] Fine Direct Testimony at 33.

[1018] Fine Direct Testimony at 33.

[1019] Fine Direct Testimony at 33.

[1020] Fine Direct Testimony at 33.

KU reiterated in rebuttal that any non-zero Rider NMS-2 avoided environmental compliance cost component would double-count any such avoided costs and would harm other customers.[1021]

Having considered the record and being otherwise sufficiently advised, the Commission finds that the avoided environmental compliance costs should remain at its current rates, consistent with the provisions of the Stipulation. Like avoided carbon costs, these values have not been updated since Case No. 2020-00349. In that case, the Commission calculated an avoided environmental compliance cost based on CCR and ELG project costs associated with each KU's coal plant ownership, spread over an estimated level of generation.[1022] In the next net-metering case, the Commission expects KU to utilize a similar methodology based on any current environmental compliance costs, such as an SCR.

Avoided Transmission Capacity. KU stated that it performed an analysis that shows the appropriate avoided transmission capacity cost component for Rider NMS-2 is zero.[1023] KU stated that it has not identified any transmission capacity projects that Rider NMS-2 customers will allow KU to avoid over the next ten years.[1024] KU's study concluded that since 20 percent penetration of solar photovoltaics (PV) on a new 500 home development would have little impact on the peak demand for each circuit studied, due to non-coincidence between solar production and load, the net impact on the

[1021] Schram Rebuttal Testimony at 12.

[1022] Case No. 2020-00349, Sept. 23, 2021 Order at 57.

[1023] McFarland Direct Testimony at 31.

[1024] McFarland Direct Testimony at 32.

transmission system would be negligible.[1025] KU also stated that avoided transmission losses are included in the avoided energy cost component.[1026] KU studied whether there were any potential cost savings on the LG&E/KU transmission system due to DERs located across the LG&E/KU service territory by identifying if there are any avoided transmission infrastructure upgrades due to NM DER generation[1027] Based on the study, KU determined that the expected savings on the transmission system upgrade projects due to NM DER generation is $0.[1028]

When asked to provide avoided transmission capacity costs, KU noted that it was willing to respond to the request, but it cannot do so because the Commission did not disclose its calculations in the Company's 2020 base rate case.[1029]

Joint Intervenors highlighted KU's planned transmission system investments through 2026.[1030] Joint Intervenors stated that DPV can displace transmission investment because transmission is built to deliver generation energy and capacity and is driven by additions of generation, not increases in demand.[1031] Joint Intervenors used transmission rates for LG&E/KU from 2016 through 2021, and extrapolated those values to 2025 based on an 11 percent annual rate of increase.[1032] Joint Intervenors then divided by solar

[1025] Waldrab Direct Testimony, PWW-2 at 5.

[1026] McFarland Direct Testimony at 32.

[1027] McFarland Direct Testimony, Exhibit BJM-3, at 3.

[1028] McFarland Direct Testimony, Exhibit BJM-3 at 6.

[1029] KU's Response to Staff's Fourth Request, Item 13(c).

[1030] Fine Direct Testimony at 29.

[1031] Fine Direct Testimony at 27.

[1032] Fine Direct Testimony at 27.

production hours (kWh per year) and ELCC (54 percent) during peak hours and determined the ELCC using the NREL PV Watts calculated average output during system peak hours in August for Louisville.[1033] Joint Intervenors recommended that avoided transmission costs for DPV is $0.0191 per kWh.[1034]

KYSEIA highlighted gaps in KU's transmission study. First, KYSEIA noted the first gap in the analysis is that "[w]inter peak models were not analyzed due to the expectation that DER generation output would be 0 percent during this time."[1035] KYSEIA also highlighted that certain avoided transmission capacity cost results indicated the potential for net metering to contribute to avoiding an MVA flow violation and a voltage violation.[1036] KYSEIA also stated that the study is silent on the potential for net metering to make a contribution to avoiding or delaying a transmission investment in conjunction with other programs such as energy efficiency, demand response, etc. – a contribution which surely would have value.[1037] KYSEIA also stated that the contribution of net metering or DG systems to making additional transmission capacity available to KU dismisses the value of existing transmission capacity that can be marketed by KU.[1038]

[1033] Fine Direct Testimony at 29.

[1034] Fine Direct Testimony at 29.

[1035] Hoyle Direct Testimony at 50.

[1036] Hoyle Direct Testimony at 51.

[1037] Hoyle Direct Testimony at 51.

[1038] Hoyle Direct Testimony at 51.

KU rebutted that no intervenor has offered a realistic alternative analysis of avoided transmission capacity costs attributable to KU's NMS-2 customers and contested the critiques laid out by intervenors.[1039]

Having considered the record and being otherwise sufficiently advised, the Commission finds that the avoided transmission costs should remain at its current rates, consistent with the provisions of the Stipulation. In Case No. 2020-00349, the Commission previously approved a modified version of the Minnesota VOS approach.[1040] The Commission simplified the approach by not accounting for PV degradation, and not adjusting transmission capacity for losses, as there was not information in the record to support those approaches. The Commission finds that in the next NMS-2 rate case, that KU should utilize the modified Minnesota Value Of Solar (VOS) methodology approved in Case No. 2020-00349 following the Commission's written step by step explanation of how to calculate the values.[1041] However, in the alternative, KU could utilize a non-modified Minnesota VOS approach, as the Commission finds such a methodology to be reasonable. If KU chooses to again study transmission costs, the Commission recommends KU address the gaps as highlighted by KYSEIA.

[1039] McFarland Rebuttal Testimony at 7.

[1040] To estimate the cost of transmission capacity, the Commission averaged LG&E/KU's joint firm point-to-point transmission service rates158 over the most recent five years to find a $/kW deferred cost of transmission, and escalated at the same rate that LG&E/KU used for distribution escalation over the 25-year lifetime of a solar resource. Finding the net present value of that deferred annual cost, annualizing the avoided cost, and dividing by expected annual solar generation yields a $/kWh avoided transmission capacity cost. To account for the time-dependent nature of capacity benefits, the Commission discounted the $/kWh avoided transmission cost by a measure of the effective capacity of solar. To do so, the Commission used LG&E/KU's average annual availability factor, which averages the availability of a sample solar production profile during monthly peak hours. Case No. 2020-00349, Sept. 23, 2021 Order at 52.

[1041] The Commission notes that it is unable to provide the workpapers from Case No. 2020-00349.

Avoided Distribution Capacity Costs. KU argued that the appropriate avoided distribution capacity cost should be zero because Rider NMS-2 has allowed KU to avoid and are not projected to allow KU to avoid any distribution capacity costs.[1042] KU stated since the 2020 rate cases, KU can now know with a much higher degree of certainty; the location, magnitude, and type of NMS-2 generation.[1043] KU explained that when distributed energy resources (DERs) are dispatchable, the serving utility can use them, for example, to time-shift peak demand on circuits nearing capacity to offset the need for capacity upgrades; however, KU does not currently have the capability to dispatch distributed energy resources, but are exploring these capabilities with industry peers and research groups.[1044]

KU also performed modeling using AMI data from two representative circuits, to determine the net impact on the distribution and transmission systems.[1045] KU stated that distribution impacts are limited to the possibility of needing larger service transformers to handle excess solar generation.[1046] KU stated that no savings are possible on the distribution system due to adequate capacity already being present.[1047] KU stated that distribution services provided by the distributed generator (DG) are possible, but this is not feasible until Distributed Energy Resource Management (DERMS) is implemented,

[1042] Waldrab Direct Testimony at 40-41.

[1043] Waldrab Direct Testimony at 40.

[1044] Waldrab Direct Testimony at 40.

[1045] Waldrab Direct Testimony, Exhibit PWW-3 at 5.

[1046] Waldrab Direct Testimony, Exhibit PWW-3 at 5.

[1047] Waldrab Direct Testimony, Exhibit PWW-3 at 5.

and independent production meters are installed to monitor asset performance.[1048] KU also highlighted that any benefits from distribution services would be localized near the DG interconnection and would provide minimal impact at the distribution substation.[1049]

When asked to provide avoided distribution capacity costs, LG&E noted that it was willing to respond to the request, but it cannot do so because the Commission did not disclose the details of the calculations used by the Commission in the Company's 2020 base rate case.[1050]

Joint Intervenors cited that the Commission directed KU to calculate avoided distribution costs and established a benchmark for 2020 at $0.00129 per kWh for LG&E and $0.00185 per kWh for KU, based on a reduction in future carrying costs for distribution infrastructure additions.[1051] Joint Intervenors argued, in the absence of better data and analysis, KU ought to use benchmarks inflated to the present, using the Consumer Price Index (CPI 125 percent from 2020 to 2025), which equals $0.0023 per kWh for KU.[1052]

Joint Intervenors stated that KU is not planning to facilitate DER utilization and that the lack of action is particularly egregious because the Commission directed KU to justify its costs of Advanced Distribution Management Solutions (ADMS) and DERMS systems.[1053] Joint Intervenors also stated that marginal distribution costs must be calculated on a long-term basis, that is 30 to 40 years, that reflects the book life of the

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[1048] Waldrab Direct Testimony, Exhibit PWW-3 at 5.

[1049] Waldrab Direct Testimony, Exhibit PWW-3 at 5.

[1050] KU's Response to Staff's Fourth Request, Item 13(c).

[1051] Fine Direct Testimony at 30.

[1052] Fine Direct Testimony at 30.

[1053] Fine Direct Testimony at 31.

assets and even using the deferral method requires that it be calculated based on a lifetime cost of near term investment and then of a more distant period and then calculating the difference in net present value costs between the two cases.[1054]

KYSEIA argued that the small magnitude of benefits KU found are due partly to study design, partly to interconnection rules for net metering that constrain geographic aggregation of participants, and due to the low rate of net metering adoption which is influenced by the low value of net metering exports and undifferentiated price signals.[1055] KYSEIA argued that KU is undermining available cost reductions and ratepayer benefits from multiple angles, which results in increased electric costs and threatens electric affordability for all ratepayers.[1056]

KYSEIA highlighted flaws that it found with the study: (1) use of a clipped production profile; (2) the small sample size; (3) the lack of complete meter data and changing study participants over the study period; (4) the exclusive focus on new construction rather than benefits on the existing distribution system; (5) the 2020 year study period; and (6) focus on a single circuit peak.[1057]

KU noted that no intervenor has offered a data-driven alternative analysis or calculation of avoided distribution capacity costs attributable to KU' NMS-2 customers.[1058]

[1054] Fine Direct Testimony at 30.

[1055] Hoyle Direct Testimony at 45.

[1056] Hoyle Direct Testimony at 45.

[1057] Hoyle Direct Testimony at 46.

[1058] Waldrab Rebuttal Testimony at 8.

In Case No. 2020-00349, the Commission used a modified Minnesota VOS approach.[1059] The Commission explained:

> To estimate the cost of each distribution system's capacity, the Commission utilized the most recent two years and forecasted three years of capital costs and new capacity associated with capacity-related distribution projects. Deferring a distribution capital cost for the lifetime of a solar system saves LG&E/KU the amount of money it could invest at today's weighted average cost of capital to achieve the same escalated distribution cost. The annualized net present value of those savings can be divided by annual solar production to represent the value of each solar kWh. As with transmission capacity, the Commission discounted the $/kWh avoided distribution cost by LG&E/KU's annual average solar availability factor.[1060]

Having considered the record and being otherwise sufficiently advised, the Commission finds that the avoided distribution capacity costs should remain at its current rates, consistent with the provisions of the Stipulation. The Commission recommends that in the next NMS-2 rate case, that KU should utilize the modified Minnesota VOS methodology approved in Case No. 2020-00349 following the Commission's written step by step explanation of how to calculate the values or utilize a non-modified Minnesota VOS approach, as the Commission finds such a methodology to be reasonable.[1061] If KU chooses to study distribution costs, the Commission finds that KU should address the flaws as highlighted by KYSEIA. As the Commission agrees with KYSEIA that there are numerous flaws in KU's distribution study, the Commission does not believe that KU has met its burden of proof regarding a zero value for avoided transmission costs.

[1059] Case No. 2020-00349, Sept. 23, 2021 Order at 54.

[1060] Case No. 2020-00349, Sept. 23, 2021 Order at 54.

[1061] The Commission notes that it is unable to provide the workpapers from Case No. 2020-00349.

Job Benefits. KU stated that it is not proposing an NMS-2 rate component related to job benefits because such benefits are outside of the Commission's jurisdiction.[1062] KU also highlighted that the Commission recently approved net metering rates for Duke Kentucky that did not include a jobs benefit component, which Duke Kentucky argued should be zero for the same reason.[1063]

Joint Intervenors stated that, though jobs are not within the boundaries of utility finance, employment is a critical element of ratepayers' well-being as it portrays broader economic conditions.[1064] Joint Intervenors also argued that jobs related to distributed photovoltaics DPV are calculatable.[1065] Joint Intervenors conducted an analysis that examined the benefits to the state's economy caused by a thriving DPV industry.[1066] The growth scenario was analyzed using the Jobs and Economic Development Impact modeling (JEDI) tool created by the National Renewable Energy Laboratory (NREL).[1067] Joint Intervenors compared the construction and installation phases of a 500 MW capacity addition across generation types. Joint Intervenors found that DPV produces the largest economic boost by a wide margin, creating over 13,600 jobs and generating $753 million in earnings, nearly $2 billion in output, and more than $1.15 billion in value added or added gross state product (GSP). For local benefits, in the analysis, Joint Intervenors

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[1062] Hornung Direct Testimony at 18 citing *EnviroPower, LLC v. Public Service Commission of Kentucky*, 2007 WL 289328 at *4 (Ky. App. 2007) (not to be published) and ; Case No. 2011-00140,*The 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, (Ky. PSC July 8, 2011), Order at 4.

[1063] Hornung Direct Testimony at 18-19.

[1064] Fine Direct Testimony at 36.

[1065] Fine Direct Testimony at 36.

[1066] Fine Direct Testimony, Exhibit JF-2, at 1.

[1067] Fine Direct Testimony, Exhibit JF-2, at 2.

stated that DPV sustains 209 jobs with $16 million in added GSP and 91 percent of spending retained locally, while utility solar supports 134 jobs with $10 million in added GSP and an even higher 92 percent local spending share.[1068]

KYSEIA stated that KU provided no meaningful analysis of the NMS-2 rate component related to job benefits and that KU failed to fulfill the requirement to evaluate job benefits and economic development as an export rate component.[1069]

KU rebutted that the study shows that mounting solar on numerous rooftops requires many more people than does installing the same amount of solar in a single field as part of a utility-scale installation, but that does not make it economical or beneficial.[1070] KU recommended that the Commission should remove it from future consideration for Rider NMS-2 compensation rates.[1071]

The Commission finds that, as no job benefits value was previously assigned, that consistent with the Stipulation, there is no change to any job benefits credit to NMS-2. The Commission acknowledges that, while it has ordered studies for job benefits, it has never assigned a dollar value to be included in the avoided cost rates. However, both Joint Intervenors and KYSEIA are correct that in Case No. 2020-00349, the Commission directed KU to evaluate job benefits and economic development as an export rate component for KU's next rate case filing.[1072] KU should follow through with evaluating

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[1068] Fine Direct Testimony, Exhibit JF-2 at 7.

[1069] Hoyle Direct Testimony at 53.

[1070] Schram Rebuttal Testimony at 13.

[1071] Schram Rebuttal Testimony at 13.

[1072] Case No. 2020-00349, Sept. 23, 2021 Order at 57-58.

these benefits as previously ordered. KU had the opportunity to contest the Commission's Order in the previous case but chose not to do so.

Other Avoided Cost Values

Joint Intervenors proposed line loss, risk hedge value, and reserve margin as avoided costs that were not previously included in the avoided cost calculation. Joint Intervenors calculated line loss by multiplying transmission line loss rates by avoided costs for generation capacity, generation energy, energy price hedge value, reserve margin, transmission, distribution and ancillary services because line losses increase each of these cost components as power is transmitted from utility-scale plants to customers' premises where DPV are installed.[1073] Joint Intervenors recommended a $0.008/kWh line loss value for KU.[1074] For reserve margin, Joint Intervenors multiplied generation capacity costs by the reserve margin, which peaks at 29 percent in KU workpapers to arrive at $0.0067 per kWh.[1075] As noted above, Joint Intervenors recommended the Commission also contemplate including an energy price risk hedge benefit created by using renewables to meet incremental load.[1076] Joint Intervenors stated that fossil fuel energy price shocks have occurred about twice per decade historically, and ratepayers are exposed to that volatility when the generation is powered

[1073] Fine Direct Testimony at 35.

[1074] Fine Direct Testimony at 35.

[1075] Fine Direct Testimony at 34.

[1076] Fine Direct Testimony at 18.

by natural gas.[1077] Joint Intervenors recommended a $0.0140/kWh energy price risk value for KU.[1078]

KU argued the reserve margin component double-counts avoided generation capacity costs, and the Commission should ignore it, because KU's generation capacity needs include having sufficient capacity to satisfy their reserve margin requirements.[1079] KU argued that the Commission should disregard Joint Intervenors' proposed risk hedge value component because the avoided energy cost component fully compensates for it.[1080]

Having considered the record and being otherwise sufficiently advised, as the avoided cost values should remain at its current rates, consistent with the provisions of the Stipulation, the Commission need not further address these proposals in this case.

<u>Netting Methodology</u>

KU's current tariff sheet states the following:

> For each billing period, Company will net the dollar value of the total energy consumed and the dollar value of the total energy exported by Customer as follows: Company will (a) bill Customer for all energy consumed from Company in accordance with Customer's standard rate and (b) Company will provide a dollar denominated bill credit for each kWh Customer produces to the Company's grid.[1081]

KU explained that, if in May, a customer consumed 800 kWh from its grid and produced 300 kWh to the Company's grid, KU would bill the customer at applicable retail

[1077] Fine Direct Testimony at 19.

[1078] Fine Direct Testimony at 19.

[1079] Schram Rebuttal Testimony at 12.

[1080] Schram Rebuttal Testimony at 12.

[1081] P.S.C. No. 20, Second Revision of Original Sheet No. 58.

rates for all 800 kWh of usage and provide a dollar denominated bill to the customer for all 300 kWh of production at the applicable Rider NMS-2 rate.[1082] KU confirmed that the text has not changed since the Commission's November 30, 2021 acceptance of the Company's Rider NMS-2 tariff sheets following its November 4, 2021 rehearing order in Case No. 2020-00349.[1083]

Joint Intervenors argued that for NMS-2 customers, KU is calculating bill credits using "instantaneous netting" of all solar exports, rather than using monthly netting, as required by statute and previous Commission orders.[1084] Joint Intervenors argued that this practice lowers the potential compensation for NMS-2 customers because it leaves other (monthly) bill charges out of the netting equation including fuel charges.[1085] Joint Intervenors also explained that when the export rate is lower than the retail rate, instantaneous netting devalues all solar exports, rather than just the net exports at the end of the billing period.[1086]

KU rebutted that Rider NMS-2 is fully in compliance with the Commission Orders, as well as KRS 278.465 and 278.466, which the Commission itself has stated.[1087]

Prior to the change to the net metering statutes that took effect on January 1, 2020, KRS 278.465(4) defined net metering as

> measuring the difference between the electricity supplied by the electric grid and the electricity generated by an eligible

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[1082] KU's Response to Staff's Fourth Request, Item 16.

[1083] KU's Response to Staff's Fourth Request, Item 16.

[1084] Fine Direct Testimony at 41.

[1085] Fine Direct Testimony at 40-41.

[1086] Fine Direct Testimony at 41.

[1087] Conroy Rebuttal Testimony at 16.

> customer generator that is fed back to the electric grid over a billing period.

Effective January 1, 2020, KRS 278.465(4) was revised to define net metering

> as the difference between the (a) dollar value of all electricity generated by an eligible customer-generator that is fed back to the electric grid over a billing period and priced as prescribed in KRS 278.466; and (b) dollar value of all electricity consumed by the eligible customer-generator over the same billing period and priced using the applicable tariff of the retail electric supplier.

In Case No. 2020-00349 and 2020-00350, the Commission, described netting as netting the total energy consumed and the total energy exported by eligible customer-generators over the billing period, consistent with the language in Kentucky Power's case.[1088] However, the Commission, in its Order on rehearing, clarified that *consistent* with its finding in Case No. 2020-00174 and KRS 278.465(4), the netting process is to net the *dollar value* of the total energy consumed and the *dollar value* of the total energy exported.[1089]

Having considered the record and being otherwise sufficiently advised, the Commission finds that KU's netting methodology is reasonable and consistent with both Commission Orders and KRS 278.465(4). The Commission agrees with KU's interpretation and does not find Joint Intervenors argument compelling as both KU's explanation and its tariff highlight that its calculation occurs over the billing period.

<u>1 Percent Cap</u>

KRS 278.466(1) states that

[1088] Case No. 2020-00349 Sept. 24, 2021 Order at 4

[1089] Case No. 2020-00349, Nov. 4, 2021 Order at 11-12.

> each retail electric supplier shall make net metering available to any eligible customer-generator that the supplier currently serves or solicits for service. If the cumulative generating capacity of net metering systems reaches one percent (1 percent) of a supplier's single hour peak load during a calendar year, the supplier shall have no further obligation to offer net metering to any new customer-generator at any subsequent time.

Joint Intervenors mentioned that in offering a fair NMS-2 rate, KU can also continue to offer it after the 1 percent threshold is reached without concerns about cross subsidies nor the need to update the NMS rate.[1090] Joint Intervenors stated that KU's proposal to stop offering NMS-2 beyond the 1 percent threshold unreasonably and unnecessarily truncates the potential for the program to deliver benefits for both participants and non-participants.[1091]

KYSEIA recommended that the 1 percent net-metering cap be calculated based on the AC generating capacity rather than on the DC power rating, and KU should be directed to provide justification for the reasonableness of its proposal to close Rider NMS-2 to new customers.[1092] KYSEIA explained that the DC capacity of a PV system is a power rating of the photovoltaic panels themselves based on standard test conditions – the miles-per gallon (MPG) rating for a new car model would be similar-type rating in that it is based on standard test conditions – but the DC power rating is not the same as the "generating capacity" of a solar system.[1093] KYSEIA also explained that PV systems generating capacity, or the useful electric output of a PV system, is always less than the DC power

[1090] Fine Direct Testimony at 9.

[1091] Fine Direct Testimony at 41.

[1092] Hoyle Direct Testimony at 54.

[1093] Hoyle Direct Testimony at 38.

rating of the PV panels due to system losses, DC-to-AC conversion efficiency of the inverter, and can even be affected by weather conditions such as cloud cover or temperature – all of which are inputs into PV Watts.[1094] KYSEIA stated that the PV Watts program's default adjustments to the DC power rating 14.08 percent system losses, 96 percent inverter efficiency, and a DC-to-AC size ratio of 1.2 to determine a modeled PV system's useful electric output, or generating capacity.[1095] KYSEIA explained that A PV system's generation of AC power is always constrained by its inverter capacity. For instance, for a 10 kW-DC system, applying the default PV Watts DC-to-AC size ratio of 1.2, results in a generating capacity of 8.3 kW-AC.[1096]

KYSEIA stated that although KU will not be statutorily obligated to continue offering net metering to new customer-generators by KRS 278.466(1) after the 1 percent threshold is reached, Rider NMS-2 is still a regulated retail rate and a proposal to close a retail rate to new customers should be supported with adequate justification by KU and evaluated for reasonableness by the Commission, particularly in view of KU's representations concerning anticipated growth in peak load.[1097]

KU stated that it is not proposing to close Rider NMS-2 in this proceeding.[1098] KU stated that all it has proposed to do is add text to its tariffs that alerts customers of its

[1094] Hoyle Direct Testimony at 38.

[1095] Hoyle Direct Testimony at 39.

[1096] Hoyle Direct Testimony at 39.

[1097] Hoyle Direct Testimony at 40.

[1098] Hornung Rebuttal Testimony at 11.

intention to seek Commission approval to close the Rider NMS-2 tariffs at some point after reaching the statutory threshold.[1099]

As noted above, the Stipulation states that KU agreed that it will not close NMS-2 rates to new participants earlier than the effective date of new rates resulting from their next base rate cases.[1100]

The Commission acknowledges KU's commitment in the Stipulation. However, if KU at any time in the future proposes to close its Rider NMS-2 to new customers, KU should file notice and include a description and the calculation of the 1 percent. The Commission agrees with KYSEIA that using a DC-AC size ratio is appropriate for purposes of this calculation.

Other Proposals

Joint Intervenors recommended that KU should plan for achieving a high DER scenario that far exceeds what is considered in the 2024 Integrated Resource Plan (IRP) or the 2025 Certificate for Public Convenience and Necessity (CPCN) forecasts.[1101] Joint Intervenors stated that DER capacities will continue their trend of expansion in Kentucky, as has been observed in other jurisdictions and that KU must plan for hosting and optimizing these resources, rather than to continue to deny their potential for delivering value to all ratepayers.[1102] Joint Intervenors recommended that KU should take steps to make installed DPV increasingly valuable by increasing scales, geographic coverage, and

[1099] Hornung Rebuttal Testimony at 11.

[1100] Stipulation, Article 9.13.

[1101] Fine Direct Testimony at 7.

[1102] Fine Direct Testimony at 7.

pairing of other DER (e.g., EV charging, batteries, energy efficiency) and pricing programs (e.g., Time of Use (TOU) rates, demand response).

KU rebutted this stating Mr. Fine's policy-related arguments favoring DERs to support higher Rider NMS-2 compensation rates are contrary to the General Assembly's stated polices concerning fossil units and outside the Commission's jurisdiction concerning "non monetizable benefits."[1103]

KYSEIA recommended KU include battery-coupled DG resources into their Rider NMS-2, with appropriate price signals, and also recommended the Commission consider the resilience benefits offered by these systems to all ratepayers in its evaluation of a just and reasonable compensation rate for net metering exports.[1104]

KU rebutted that Kentucky's net metering statutes clearly state what qualifies as an eligible electric generating facility, and it includes only facilities that generate electricity using solar, wind, biomass, biogas, or hydro energy; nowhere does it mention energy storage of any kind.[1105] Following the statutory definition, KU' Rider NMS-2 also does not address or compensate energy storage.[1106]

Having considered the record and being otherwise sufficiently advised, the Commission encourages KU to continue to study the benefits related to DER expansion in its next IRP. The Commission also agrees with KU that the NM-2 statute does not contemplate energy storage.

[1103] Conroy Rebuttal Testimony at 14.

[1104] Hoyle Direct Testimony at 58.

[1105] Hornung Rebuttal Testimony at 13.

[1106] Hornung Rebuttal Testimony at 13.

TARIFFS

KU proposed numerous revisions to its tariff in its application, some of which were amended as a result of the Stipulation. Below is a discussion of the significant revisions. Unless otherwise noted, the tariffs discussed below were not explicitly addressed in the Stipulation but were agreed to by Stipulating Parties under the catch-all provision and tariff sheet section.[1107] Following review of the record, including the Stipulation, the Commission finds it should make modifications to the Stipulation as it relates to the General Service/Power Service legacy status, Retired Asset Recovery, Terms and Conditions – Billing, and the Net Metering Interconnection Guidelines.

General Service Time-of-Day (GTOD) Rates

Under KU's current tariff, the GTOD-Energy and GTOD-Demand rate schedules are limited to General Service (Rate GS) customers participating in the Advanced Metering Systems Offering, which was a limited participation smart meter pilot program KU provided as part of its Demand Side Management-Energy Efficiency (DSM-EE) program portfolio.[1108] Currently, 41 KU customers take service under one of the GTOD rate schedules.[1109] KU proposed to make the GTOD rate schedules available to up to 500 customers total across both GTOD rates due to the fact that its advanced metering infrastructure deployment is nearly complete.[1110] KU stated that this will allow participation to grow and provide useful data while keeping the number of eligible

[1107] Stipulation, Article 5.2; Amended Stipulation, Article 11.1.

[1108] Hornung Direct Testimony at 8.

[1109] Hornung Direct Testimony at 8.

[1110] Hornung Direct Testimony at 8.

customers low and minimizing any potential adverse revenue impacts.[1111] Due to the limited number of GS customers who participated in the original pilot, KU states that it had not observed any significant revenue impacts from the offerings.[1112] No intervenors provided testimony on this issue.

Having considered the record and being otherwise sufficiently advised, the Commission finds that KU's proposal to limit the availability of the GTOD rate schedules is reasonable and should be approved. The same customer limit already applies to KU's Residential Time-of-Service rate schedules. Given the current minimal participation in the GTOD rate schedules, the customer limit will allow KU to assess customer interest in the rate schedules and allow it to determine whether there are any adverse revenue impacts as a result of the offering of the GTOD rates.

Legacy Status of General Service and Power Service Customers

In Case No. 2008-00251,[1113] 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,[1114] KU revised the availability provisions of Rate GS and Rate PS to state that legacy customers that elect to take service under

[1111] Hornung Direct Testimony at 8.

[1112] KU's Response to Staff's Fourth Request, Item 4(b).

[1113] Case No. 2008-00251, *Application of Kentucky Utilities Company for an Adjustment of Electric Base Rates* (Ky. PSC Feb. 5, 2009).

[1114] Case No. 2012-00221, *Application of Kentucky Utilities Company for an Adjustment of its Electric Rates* (Ky. PSC Dec. 20, 2012).

another rate schedule for which they qualify could not take service under the rate schedule for which they had legacy status again unless and until they met the availability requirements of the rate. In Case No. 2020-00349,[1115] 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 dates the new rates would have gone into effect in that proceeding. The Commission rejected KU's proposal in Case No. 2020-00349 due to possible revenue shifting between Rate GS and Rate PS and due to possible frustration and confusion for those customers who would lose their legacy status and be forced to switch rate schedules if they fail to meet the eligibility requirements of their current rate schedule in the future.[1116]

In the current proceeding, KU indicated that it was proposing to remove legacy status from customers that meet the availability requirements of their rate schedules on the date new rates go into effect from these proceedings.[1117] However, KU did not initially propose any tariff changes to Rate GS or Rate PS that would remove legacy status for such customers, only mentioning the change in direct testimony.[1118] In addition, KU did not include any information in the initial public notice of this change. KU did later add information pertaining to this change to the revised customer notice that was posted to its website.[1119]

[1115] Case No. 2020-00349, June 30, 2021 Order.

[1116] Case No. 2020-00349, June 30, 2021 Order at 54.

[1117] Hornung Direct Testimony at 10.

[1118] Hornung Direct Testimony at 9–10.

[1119] KU's Response to the Commission's June 16, 2025 Order.

Of the 1,035 Rate GS customers that are currently considered legacy customers, KU indicated that approximately 457 of those customers are currently eligible for Rate GS based upon their current usage patterns.[1120] Of the 563 Rate PS customers that are currently considered legacy customers, KU indicated that 79 of those customers are currently eligible for Rate PS based upon their current usage patterns.[1121] KU disagreed with the Commission's reasoning in Case No. 2020-00349 that removing legacy status could result in revenue shifting between Rate GS and Rate PS by moving the rate classes away from the approved revenue allocation.[1122] KU argued that this is true for all non-residential customers whose service characteristics change such that they would need to be moved to another rate schedule.[1123] KU also disagreed with the Commission's reasoning in Case No. 2020-00349 that removing legacy status from customers would create frustration and confusion for those customers who lose legacy status and are forced to switch rate schedules.[1124] KU argued again that customers losing their legacy status would be like all other customers that qualify for a rate schedule and later do not.[1125] KU indicated that it never meant for the legacy status created in Case No. 2008-00251 to be permanent and that its proposal in this proceeding is a reasonable step toward winding down a provision that was always meant to be temporary.[1126]

[1120] Hornung Direct Testimony at 10.

[1121] Hornung Direct Testimony at 10.

[1122] KU's Response to Staff's Second Request, Item 20(e).

[1123] KU's Response to Staff's Second Request, Item 20(e).

[1124] KU's Response to Staff's Second Request, Item 20(e).

[1125] KU's Response to Staff's Second Request, Item 20(e).

[1126] KU's Response to Staff's Second Request, Item 20(e).

In the Stipulation, the Signing Parties agreed that KU will remove legacy status from those customers that meet the availability requirements of their rate schedules on the date new rates go into effect from these proceedings.[1127] Per the Stipulation, Rates PS and GS customers that do not meet the availability requirements of their rate schedules will continue to maintain legacy status.[1128]

Having considered the record and being otherwise sufficiently advised, the Commission finds that KU's proposal to remove legacy status from those legacy GS and PS customers that meet the availability requirements of the current tariff that they are on is reasonable and should be approved. As KU notes, all other non-residential customers are subject to having their rate schedule changed should their service characteristics change over time. However, since the affected customers will have had legacy status for over 16 years and have not had to worry about being moved to another rate schedule if their service characteristics changed, the Commission finds that KU should proactively notify and work with the affected customers in the future when the customer's service characteristics have them on the path to having the rate schedule they are served under changed. In addition, the Commission finds that the following language should be included in Rate PS and GS "[c]ustomers who are receiving service under this tariff who meet the availability terms as of [date of the Order] will no longer be eligible for the legacy status as outlined above."

Electric Vehicle Tariffs

[1127] Stipulation, Article 9.10.

[1128] Stipulation, Article 9.10.

KU proposed to combine its Electric Vehicle Charging Service – Level 2 rate schedule (Rate EVC-L2) and Electric Vehicle Fast Charging Service (Rate EVC-FAST) rate schedule into a single Electric Vehicle Charging Service tariff.[1129] KU explained that the change was proposed for simplicity purposes since the terms of the two tariffs are nearly identical.[1130] The main difference between the two rate schedules is that the Rate EVC-L2 charge is based on an hourly charge while the Rate EVC-FAST charge is a per kWh charge.[1131] KU explained that as electric vehicle (EV) markets have developed, billing has shifted to kWh charges, which better reflects actual charging usage and standardizes costs regardless of charger type.[1132] No intervenor provided testimony on this issue.

Having considered the record and being otherwise sufficiently advised, the Commission finds that KU's proposal to combine Rate EVC-L2 and EVC-FAST is reasonable and should be approved.

Public EV Charging Rate

Wal-Mart noted that KU does not currently offer, nor is it proposing to offer, a rate structure specifically for customers who are interested in owning and operating public EV charging equipment, specifically Direct Current Fast Chargers.[1133] Wal-Mart contends that offering a robust public EV charging network would help support the EV industry and

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[1129] Hornung Direct Testimony at 15.

[1130] KU's Response to Staff's Second Request, Item 27.

[1131] Hornung Direct Testimony at 15.

[1132] KU's Response to Staff's Third Request, Item 21.

[1133] Perry Direct Testimony at 28.

encourage EV adoption.[1134] Wal-Mart contends that the Commission should require KU to work with interested stakeholders to develop an EV Charging rate specific for public EV chargers.[1135]

In its rebuttal testimony, KU stated that Wal-Mart did not provide any cost-based justification for the rate it proposes the Commission to compel KU to develop.[1136] KU also stated that the Commission has indicated that it does not have jurisdiction over the rates EV charger owners charge their customers and that if Wal-Mart is not charging its customers a sufficient amount to recoup its EV charger related costs, it is free to change the prices.[1137] In the Stipulation, KU agreed to work with Walmart to propose an EV fast charger rate in their next base rate cases.[1138] The Commission has noted in prior cases, and most recently in Case No. 2024-00354,[1139] that it agrees public EV charging stations are important to the encouragement of EV adoption and that engagement with stakeholders to assess fair and efficient means of providing customers the services they want is important. Therefore, the Commission encourages KU to follow through with its commitment to work with Wal-Mart to develop an EV fast charger rate in its next base rate case.

<u>Green Tariff</u>

[1134] Perry Direct Testimony at 28–29.

[1135] Perry Direct Testimony at 30–31.

[1136] Hornung Rebuttal Testimony at 18.

[1137] Hornung Rebuttal Testimony at 18.

[1138] Stipulation, Article 9.4.

[1139] Case No. 2024-00354, *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 Oct. 10, 2025).

In the Stipulation, the Stipulating Parties agreed that KU would modify its tariff to make Green Tariff Option #3 available to customers served under Rate PS so long as the rate design proposed by the Stipulation is approved by the Commission.[1140] Green Tariff Option #3 allows customers who wish to purchase the electrical output and all associated environmental attributes from a renewable energy generation to bilaterally contract with KU.[1141] Currently, Green Tariff Option #3 is available to customers served under Rates Time-of-Day Secondary Service (TODS), Time-of-Day Primary Service (TODP), Retail Transmission Service (RTS), and Fluctuating Load Service (FLS).[1142]

KU indicated that when Green Tariff Option #3 was established, Rate PS was not included as it contained a single demand rate, which differed from the other rate schedules within which Option #3 was available.[1143] As noted above, KU has proposed in this proceeding to change the Rate PS demand rates from a non-time differentiated seasonal demand rate to the same time-of-use, base-intermediate-peak demand structure as Rates TODS, TODP, RTS and FLS.[1144]

Having considered the record and being otherwise sufficiently advised, the Commission finds that allowing Rate PS customers to be eligible for Green Tariff Option #3 is reasonable and should be approved. As stated earlier, the Commission finds the rate design for the Rate PS as proposed by the Stipulation reasonable. Rate PS customers already have the opportunity to participate in Green Tariff Option #1 and #2,

[1140] Stipulation, Article 9.5.

[1141] Application, Tab 5 at 124.

[1142] Application, Tab 5 at 124.

[1143] HVT of the November 4, 2025 Hearing, Robert M. Conroy, 11:14:20–11:15:30.

[1144] Hornung Direct Testimony at 9.

and with the Commission's approval of the change to the Rate PS demand rate structure in this proceeding, Rate PS customers should be on a level playing field with Rates TODS, TODP, RTS, and FLS.

Solar Share Program

KU proposed to revise the Solar Share Program Rider (Rider SSP) to open Rider SSP to Retail Transmission Service (Rate RTS) customers, to remove the restriction from the One-Time Solar Capacity Charge that limited its use to Solar Share Facilities that had not begun construction, to remove the cap on the amount of Solar Share Facilities capacity a customer could subscribe to, and to reduce the number of days a customer has after terminating service to transfer their Rider SSP subscription from 60 days to 30 days.[1145]

KU stated that removing the One-Time Solar Capacity Charge restriction would allow customers new to Rider SSP to begin enjoying the benefits of Rider SSP immediately.[1146] Due to a better understanding of customer de-enrollment patterns, KU indicated that it is in the best interest of those wanting to participate in Rider SSP to utilize available shares from customers who have exited the program versus waiting to fully subscribe a subsequent section of the array.[1147]

Under the current tariff, the amount a customer can subscribe to is limited to an aggregate of 500 kW DC, though no subscriber can subscribe to more than 250 kW DC

[1145] Hornung Direct Testimony at 20–21.

[1146] Hornung Direct Testimony at 20–23.

[1147] KU's Response to Staff's Third Request, Item 9.

in a single Solar Share Facility.[1148] KU indicated that the intent of the subscription limits was to avoid a single customer from purchasing the capacity of the entire array when others had expressed interest.[1149] KU stated that the interest of single-share subscribers has lessened over time, reducing the ability to support fully subscribing each facility only with customers electing to subscribe up to four shares.[1150] KU also stated that the current limits require additional marketing to fully subscribe a section and lessens its ability to satisfy the need of customers with larger sustainability goals.[1151]

Regarding the number of days a customer has to transfer their subscriptions when terminating service, KU stated that it has found that customers who wish to transfer their subscriptions upon termination of service do so within 30 days, while customers that do not do so within 30 days usually do not respond to KU's attempts at contact.[1152]

KU indicated that the proposed revisions help advance the purposes of Rider SSP and speed up the pace of building new Solar Share Facilities.[1153] No intervenors provided testimony on these issues.

Having considered the record and being otherwise sufficiently advised, the Commission finds that the revisions to Rider SSP are reasonable and should be approved.

[1148] Application, Tab 5 at 133..

[1149] KU's Response to Staff's Third Request, Item 10.

[1150] KU's Response to Staff's Fourth Request, Item 5.

[1151] KU's Response to Staff's Fourth Request, Item 5.

[1152] Hornung Direct Testimony at 21.

[1153] Hornung Direct Testimony at 21.

Retired Asset Recovery Adjustment Clause

To provide some background, in Case No. 2024-00317,[1154] LG&E filed revisions to its Retired Asset Recovery Rider (Rider RAR) tariff sheets. The proposed revisions in that case consisted of: (1) removing the cost of jurisdictionalizing revenue requirements for LG&E's retired generating units; (2) removing reference to regulatory assets; (3) revising the definitions of Retirement Costs and Retired Asset; (4) clarifying that Rider RAR cost recovery begin the month after a unit retires; (5) clarifying that the weighted average cost of capital return component applies to the retired asset balance; (6) clarifying what costs embedded in base rates should be credited against costs recovered through Rider RAR; and (7) adding a reference to Environmental Cost Recovery Surcharge revenues to indicate that Rider RAR is calculated on these revenues as well for Group 2 customers, not just Group 1 customers.[1155] With the exception of the provision pertaining to the Environmental Cost Recovery Surcharge, the Commission rejected the tariff revisions since LG&E failed to provide notice of the revisions to the other parties to the Stipulation entered into in Case No. 2020-00350.[1156]

Here, KU proposed the same revisions, along with a proposal to make Rider RAR an adjustment clause, to its Rider RAR in the current proceeding. Notice was given to the other parties to the 2020-00349 Stipulation through the customer notice provided in this case.[1157] No intervenors provided any testimony on this issue. In Case No. 2024-

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[1154] Case No. 2024-00317, *Electronic Application of Louisville Gas and Electric Company for Approval of Retired Asset Recovery Rider Cost Recovery for the Retirement of Mill Creek Unit 1 and of Retired Asset Recovery Rider Tariff Revisions and Monthly Reporting Forms.*

[1155] Direct Testimony of Andrea M. Fackler in Case No. 2024-00317 at 6–7.

[1156] Case No. 2024-00317, Feb. 24, 2025 Order at 12.

[1157] Application, Tab 6, Exhibit C, page 30–32 of 53.

00317, LG&E indicated that, while it was proposing to remove the concept of jurisdictionalizing its revenue requirements under Rider RAR, the concept would apply to KU since KU has retail operations in Virginia and wholesale municipal customers in Kentucky.[1158] However, in the current proceeding, KU has also proposed to remove the concept of jurisdictionalizing its revenue requirements under Rider RAR. After the hearing in this matter, KU provided an updated Tariff RAR that reinserted the concept of jurisdictionalizing the revenue requirement for KU's retired generating units.[1159]

Having considered the record and being otherwise sufficiently advised, the Commission finds that the proposed revisions to Rider RAR as modified by KU after the hearing in this matter are reasonable and should be approved as the revisions provide clarity as to how the rider will be applied. In this case, the change made after the hearing is material; however, one made to reflect the original tariff. However, the Commission reminds KU that all parties are entitled to notice of changes and changes made after a hearing may be rejected in future cases.

AMI Opt-Out Provision

KU proposed to include a provision in its tariff that would require customers who, for whatever reason, refuse to make adequate provision for an AMI meter, to pay the AMI Opt-Out Charges.[1160] KU explained that situations have arisen in which customers have refused to opt-out of AMI installation while refusing to provide a safe location for an AMI

[1158] Case No. 2024-00317, Direct Testimony of Andrea M. Fackler at 6.

[1159] KU's Response to Staff's Post-Hearing Request, Item 53.

[1160] Hornung Direct Testimony at 17.

meter, which places KU's personnel in an unsafe situation when installing the AMI meters.[1161]

KU explained that, while the above situation occurs infrequently, customers must provide access to KU personnel in order to maintain equipment including placing meters on customer-owned equipment and that when the customer-owned equipment is unsafe, KU's personnel are placed at risk when maintenance or emergency work is required.[1162]

Having considered the record and being otherwise sufficiently advised, the Commission finds that the proposed provision to require customers who refuse to make adequate provision for an AMI meter to pay the AMI Opt-Out Charges reasonable and should be approved. KU's personnel should be afforded a safe working environment, and the proposed revision would help provide that. The Commission does expect KU to clearly communicate to customers that are subject to this provision the ramifications of not replacing the unsafe equipment and to provide the customer ample opportunity to remedy the unsafe situation before subjecting them to the AMI Opt-Out Charges.

Terms and Conditions

Customer Responsibilities

KU proposed to revise the Customer Responsibilities section of its tariff to add an electronic mail address to the list of information it may request from customers applying for service[1163] and to revise the Permits, Easements, and Rights of Way subsection to clarify the customer's and the Company's responsibility regarding such items in order to

[1161] Hornung Direct Testimony at 17.

[1162] KU's Response to Staff's Second Request, Item 21(a)–(b).

[1163] KU's Response to Staff's Second Request, Item 1, Attachment, page 178 of 238.

comply with 807 KAR 5:006, Section 6(3).[1164] No intervenors provided testimony on these issues.

Having considered the record and being otherwise sufficiently advised, the Commission finds that the proposed revision to add an electronic mail address to the list of information KU can request from customers applying for service is reasonable and should be approved. Electronic mail is a common form of communication and having one for customers will assist KU in communicating with its customers. While KU has not given any indication that it would refuse service for a prospective customer's failure to provide an electronic mail address, the Commission strongly emphasizes that it would find such an action unreasonable as the requirement of an electronic mail address is not essential to providing utility service.

Having considered the record and being otherwise sufficiently advised, the Commission finds that the revisions to the Permits, Easements, and Rights of Way subsection are reasonable and should be approved as they were made in order to comply with 807 KAR 5:006, Section 6(3).

Company Responsibilities

KU proposed to add a provision to its tariff to clarify that it may recover costs from customers for performing incidental or occasional utility-related services. KU stated that, pursuant to its tariff, only KU and its representatives may access the company's equipment.[1165] When KU receives requests for incidental work that requires accessing

[1164] Hornung Direct Testimony at 23.

[1165] KU's Response to Staff's Second Request, Item 24.

its equipment, the requesting customer should have to pay for such work since the customer requested it. No intervenors provided testimony on these issues.

Having considered the record and being otherwise sufficiently advised, the Commission finds that the provision pertaining to incidental or occasional utility-related services performed for customers is reasonable and should be approved as customers requesting such services should be the ones to bear the cost.

Billing

KU proposed to revise its tariff to move all customers for whom they have an email address on file to paperless billing as well as making paperless billing the default option for all new customers requesting service.[1166] KU indicated affected customers would be sent an email and letter notifying them of the change to paperless billing and the date the customer will begin to receive paperless bills.[1167] Customers who do not wish to participate in paperless billing will have the option to opt-out.[1168] No intervenors provided testimony on this issue.

The Commission has concerns with moving current customers that have email addresses on file to paperless billing, even if they do have the option to opt-out. Such customers, more than likely, have had numerous opportunities to opt-in to paperless billing in the past and have not done so. It would be easy for a customer to dismiss an email or letter regarding the switch to paperless billing and then end up being late on a payment because they did not get a bill in the mail. Therefore, having considered the

[1166] Montgomery Direct Testimony at 11.

[1167] Montgomery Direct Testimony at 11.

[1168] Montgomery Direct Testimony at 11.

record and being otherwise sufficiently advised, the Commission finds that making paperless billing the default option for customers with emails on file is not reasonable and should not be approved. However, the Commission finds that making paperless billing the default option for new customers is reasonable and should be approved as long as those customers are clearly advised of their auto-enrollment in paperless billing and the option to opt-out. New customers will be much more likely to opt-out of paperless billing if they wish when signing up for service than current customers that would be automatically switched. Based on the Commission's findings, KU indicated that the estimated savings would be reduced from $1,135,260 (split LG&E 45 percent and KU 55 percent)[1169] to $373,734 (same percentage split as above)[1170].

Deposits

KU proposed revisions to its deposit policy in its tariff to align with how the deposit policy is actually implemented.[1171] The proposed revisions mainly spell out the procedures KU goes through to determine when a deposit will be required from each class of customer, how long KU will maintain the deposit for each class of customer, and what happens should a customer fail to maintain a satisfactory payment record. No intervenor provided testimony on these issues.

Having considered the record and being otherwise sufficiently advised, the Commission finds that the proposed revisions to the deposit policy are reasonable and should be approved as the revisions provide more clarity regarding KU's deposit policy.

[1169] KU's Response to Attorney General/KIUC's First Request, Item 48(e), Attachment.

[1170] KU's Response to Staff's Fifth Request, Item 3, Attachment.

[1171] Hornung Direct Testimony at 24.

Prepay Program

In Case No. 2020-00349, the Commission directed KU to propose a prepay program in its next base rate case.[1172] KU's proposed Pre-Pay Program will be available to all residential customers excluding those on net metering, RTOD-Energy, RTOD-Demand, GS, GTOD-Energy, or GTOD-Demand.[1173] Customers must also have the following: an email and texting number on file with KU; have an AMI meter; not possess a past due balance greater than $250; not have a medical alert, disconnection moratorium, or special rider; and cannot participate in budget billing, flex pay, or auto pay programs.[1174] KU indicated that it planned to implement the Pre-Pay Program in 2028 in order to avoid stranding significant investments in its legacy Customer Information System, which is scheduled for replacement.[1175]

Customers that sign up for the Pre-Pay Program will be required to make an initial payment of $30 when signing up for the Pre-Pay Program.[1176] Pre-Pay Program customers will not be required to pay a deposit other than the initial $30.[1177] If the customer already has a deposit on file with KU, the deposit will qualify as the initial payment.[1178] For those customers that have a past due balance at the time of signing up for the Pre-Pay Program, 30 percent of each payment will be applied towards the past

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[1172] Case No. 2020-00349, June 30, 2021 Order at 16.

[1173] Montgomery Direct Testimony at 26.

[1174] Montgomery Direct Testimony at 26.

[1175] KU's Response to Staff's Second Request, Item 19.

[1176] Montgomery Direct Testimony at 27.

[1177] Montgomery Direct Testimony at 27.

[1178] Montgomery Direct Testimony at 27.

due balance.[1179] Customers will receive low-funds notifications at pre-determined triggers, however those triggers have not yet been determined.[1180] Customers may also add their own notification triggers as well.[1181] Service will be shut off once a customer's balance becomes negative.[1182] In order to re-establish service, the customer will need to make a deposit of at least $30.[1183] When a customer requests disconnection of a Pre-Pay account, any remaining balance will be transferred to other active accounts, if any, or refunded.[1184] If a customer chooses to leave the Pre-Pay Program for the standard residential program, they will not be allowed to return to the Pre-Pay Program for 12 months.[1185] While KU believes that the Pre-Pay Program complies with the notice requirements under 807 KAR 5:006, Section 15, KU did request a deviation from the notice requirements if the Commission finds that the notice requirements are not met.[1186]

The Joint Intervenors argued that KU's Pre-Pay Program should not be approved. First, Joint Intervenors stated the Pre-Pay Program will adversely affect low-income customers.[1187] Secondly, Joint Intervenors claimed that Pre-Pay programs do not match a customer's income or cash flow.[1188] The Joint Intervenors also argued that low-income

[1179] Application, Tab 4 at 183.

[1180] Application, Tab 4 at 183; KU's Response to Staff's Third Request, Item 2(d).

[1181] Application, Tab 4 at 183.

[1182] Application, Tab 4 at183.

[1183] Application, Tab 4 at 183.

[1184] Application, Tab 4 at 183,

[1185] Application, Tab 4 at 183.

[1186] Application at 33.

[1187] Direct Testimony of Roger D. Colton (Colton Direct Testimony) at 56–57.

[1188] Colton Direct Testimony at 57.

customers are not able to adequately engage in energy-saving behavior due to numerous factors.[1189]

The Joint Intervenors stated that one adverse impact of Pre-Pay Programs is the number of customers that will self-disconnect service by failing to purchase additional energy when it becomes unaffordable.[1190] The Joint Intervenors also argued that any Pre-Pay Program should be accompanied by discounts because Pre-Pay Programs impose fewer costs on a utility system and Pre-Pay Programs constitute a lesser service.[1191]

The final issue the Joint Intervenors noted regarding the Pre-Pay Program was that utilities must give proper termination notice to customers prior to disconnecting service.[1192]

KU argued, in rebuttal testimony, that the Pre-Pay Program is voluntary and that should allay many of the Joint Intervenor's concerns.[1193] KU argued that the Pre-Pay Program gives customers more flexibility than post-pay customers in terms of when payments are made and argued that such flexibility is beneficial to customers with variable incomes.[1194] In regards to the Joint Intervenors' concerns regarding notice, KU stated that customers will receive constant feedback about their account balance and

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[1189] Colton Direct Testimony at 59–60.

[1190] Colton Direct Testimony at 61–62.

[1191] Colton Direct Testimony at 62–65.

[1192] Colton Direct Testimony at 65–67.

[1193] Rebuttal Testimony of Shannon L. Montgomery at 9.

[1194] Montgomery Rebuttal Testimony at 10.

usage.[1195] KU also argued that Pre-Pay Program customers receive the same electric service as all other customers, and thus offering a discount would not reflect the actual cost to serve such customers.[1196]

KU does currently have a policy of suspending disconnections for non-payment in times of extreme heat or cold.[1197] KU stated that it would not apply the current weather disconnection policy to Pre-Pay customers as those customers can stop service on their account by simply letting funds run out and it would not want to obligate customers to more utility charges if that is not their intension.[1198]

As noted above, in Case No. 2020-00349, the Commission directed KU to propose a Pre-Pay Program in its next base rate case. The most important aspect of the Pre-Pay Program is that it is voluntary. As KU noted, customers will not be forced to take service under it, but it does give customers another option that may be attractive to some and most, if not all, of Joint Intervenors' concerns regarding the Pre-Pay Program should be allayed by that fact. The Commission has approved numerous prepay programs over the years, mostly for Rural Electric Cooperative Corporations.[1199] KU's proposed Pre-Pay Program has many of the same characteristics of Pre-Pay Programs that have been

[1195] Montgomery Rebuttal Testimony at 11.

[1196] Montgomery Rebuttal Testimony at 11.

[1197] KU's Response to Joint Intervenors' Post Hearing Request, Item 11, Attachment.

[1198] KU's Response to Joint Intervenors' Post Hearing Request, Item 12(a).

[1199] Case No. 2012-00141, *Application of Salt River Electric Cooperative Corporation for Approval of a Prepay Metering Pilot Program* (Ky. PSC Jul. 11, 2012); Case No. 2012-00260, *Application of Blue Grass Energy Cooperative Corporation for Approval of a Prepay Metering Program* (Ky. PSC Aug. 10, 2012); Case No. 2012-00437, *Application of Farmers Rural Electric Cooperative Corporation for Approval of a Prepay Metering Program Tariff* (Ky. PSC Jan. 23, 2013); Case No. 2015-00311, *Application of Inter-County Energy Cooperative Corporation for Approval of a Prepay Tariff* (Ky. PSC Mar. 17, 2016; Case No. 2015-00337, *Application of Big Sandy Rural Electric Cooperative Corporation* (Ky. PSC Apr. 7, 2016).

approved in the past. The Commission does, however, have concerns that some of the procedures that will pertain to the Pre-Pay Program have not been developed yet. KU indicated that it had not yet developed the Pre-Pay Program Service Agreement, the predetermined triggers that will notify customers of a low balance, and how a customer's daily balance will be provided to the customer.[1200] KU also noted that the monthly billing summary has not been developed yet.[1201] Nonetheless, having considered the record and being otherwise sufficiently advised, the Commission finds that the framework of the Pre-Pay Program is reasonable and should be approved with the following modifications.

KU should add the following language to number five of the terms and conditions: "The account will be disconnected regardless of weather/temperature as the customer is responsible for ensuring that the prepay account is adequately funded. If the member cannot ensure proper funding, KU recommends the member not utilize the prepay service." A review of the prepay programs approved by the Commission in the past showed that almost all indicated that prepay service would be disconnected for non-payment regardless of weather or temperature.[1202]

[1200] KU's Response to Commission Staff's Third Request, Item 2(c), 2(d), and 3.

[1201] HVT of the November 6, 2025 Hearing, Shannon L. Montgomery at 11:50:00–11:50:20.

[1202] Big Sandy Rural Electric Cooperative Corporation, P.S.C. KY. No. 2015-00337, Sheet No. 4; Blue Grass Energy Cooperative Corporation, P.S.C. No. 1, Original Sheet No. 172; Clark Energy Cooperative, Inc., P.S.C. No. 2, 3rd Revision Sheet No. 45.3; Cumberland Valley Electric, P.S.C. No. 4, Original Sheet No. 82; Farmers Rural Electric Cooperative Corporation, P.S.C. KY. No. 10, Original Sheet No. 16; Fleming-Mason Energy Cooperative, Inc, P.S.C. No. 4, Third Revised Sheet No. 2.2; Grayson Rural Electric Cooperative Corporation, P.S.C. No. 1, Original Sheet No. 21.60; Inter-County Energy, P.S.C. No. 8, Original Sheet No. 5; Kenergy Corp., P.S.C. No. 2, Original Sheet No. 22 C; Licking Valley Rural Electric, P.S.C. No. 0034, Original Sheet No. 31. Nolin RECC, P.S.C. No. 10, 2nd Revision Sheet No. 95; Owen Electric Cooperative, Inc., P.S.C. No. 6, Original Sheet No. 6D; Salt River Electric, P.S.C. No. 12, 2nd Original Sheet No. 81C; Shelby Energy Cooperative, Inc., P.S.C. KY. No. 9, Original Sheet No. 306.3; South Kentucky R.E.C.C., P.S.C. KY. No. 7, 1st Revised Sheet No. T-41.

The Commission also finds that KU should submit for review through a post-case filing the Pre-Pay Service Agreement, the pre-determined triggers that will notify customers of a low balance, how a customer's daily balance will be provided to the customer, and the monthly bill summary. The Pre-Pay Service Agreement should also be filed through the Commission's electronic Tariff Filing System. If the monthly billing summary will not include all of the information required by 807 KAR 5:006, Section 7(1)(a)1–12, KU should file a request for a deviation from that regulation.

The Commission, on its own motion, also finds that a deviation should be granted from 807 KAR 5:006, Section 15(1)(f)1. This is a common deviation that the Commission has granted for Pre-Pay Programs many times in the past due to the fact that customers are notified once their balance reaches a certain amount.

Discontinuance of Service

KU proposed revisions to its Discontinuance of Service tariff section to: (1) reduce the number of days' notice of discontinuance to customers from 15 days to 10 days in situations where the customer or applicant refuses or neglects to provide reasonable access or easements to and on the customer's or applicant's premises for the purposes of installation, operation, meter reading, maintenance, or removal of KU's property;[1203] and (2) clarify language in regards to service not being cut off less than 27 days after the mailing date of original bills to state that mailing includes all other reasonable forms of delivering written communications, including without limitation electronic mailing.[1204] No intervenors provided testimony on these issues.

[1203] KU's Response to Staff's Second Request, Item 1, Attachment 1 at 211.

[1204] KU's Response to Staff's Second Request, Item 1, Attachment 1 at 212.

Having considered the record and being otherwise sufficiently advised, the Commission finds that the proposed revisions are reasonable and should be approved. The revision to the number of days' notice of discontinuance to customers for refusal of access is in line with 807 KAR 5:006, Section 15(1)(c), which states:

> For refusal of access. If a customer refuses or neglects to provide reasonable access to premises for installation, operation, meter reading, maintenance, or removal of utility property, the utility may terminate or refuse service. The action shall be taken only if corrective action negotiated between the utility and customer has failed to resolve the situation and after the customer has been given at least ten (10) days' written notice of termination pursuant to Section 14(5) of this administrative regulation.

The revision clarifying that electronic mailing would qualify as the original mailing of a bill for those customers that choose paperless billing is reasonable as sending a paper bill to such customers would defeat the purpose of paperless billing. As a point of clarity, KU indicated that it will continue to email and mail disconnection notices for non-payment to paperless billing customers.[1205]

Rules for Transmission Level Retail Electric Service Studies

KU proposed a new section in its tariff of its terms and conditions for Rules for Retail Electric Service Studies and Related Implementation Costs to clarify and codify its practices and cost responsibility relating to customers or prospective customers requesting service resulting in Transmission Service Requests (TSR) and eventual transmission system-related additions or upgrades.[1206] Any customer that requests KU to investigate possible service that would require the issuance of a TSR to the

[1205] KU's Response to Staff's Fourth Request, Item 20.

[1206] Hornung Direct Testimony at 25.

Independent Transmission Organization will be required to pay all costs of the TSR application and studies.[1207] Prospective customers submitting such requests would also be required to enter into engineering, procurement, and construction (EPC) agreements to cover all transmission-related costs KU incurs related to any studied service.[1208] Existing customers submitting such requests would also be required to enter into an EPC agreement if the estimated construction costs exceed $10 million.[1209] No intervenors provided testimony on this issue.

Having considered the record and being otherwise sufficiently advised, the Commission finds that the addition of the Rules for Retail Electric Service Studies and Related Implementation Costs to KU's tariff is reasonable and should be approved as prospective customers that cause such costs should be responsible for the costs.

Net Metering Interconnection Guidelines.

KU proposed to update its Net Metering Service Interconnection Guidelines to reflect technological and safety standard developments since the Commission first approved uniform guidelines for such interconnections in 2009.[1210] Proposed changes include revisions to ensure adherence to KU's Interconnection Requirements for Customer-Sited Distributed Generation, to include a requirement for customers to allow communication between the customer's distributed generation equipment and KU's control systems when deemed necessary during the interconnection review process, and

[1207] Hornung Direct Testimony at 25–26.

[1208] Hornung Direct Testimony at 26.

[1209] Hornung Direct Testimony at 26.

[1210] Hornung Direct Testimony at 26.

to address system upgrades that stem from the addition of distributed generation capacity.[1211]

For Level 1 Interconnections, following company approval of an application, KU proposed a revision to require customers to resubmit their application for interconnection if there are any modifications from the initially submitted plan.[1212] KU also proposed a revision indicating that any modification in generating capacity related to existing customers taking service under Net Metering Service-1 will cause their service to be transitioned to Net Metering Service-2.[1213] KU later clarified that a decrease to an NMS-1 customer's generation capacity would not result in the loss of NMS-1 legacy status, but that an increase in the generation capacity would result in the loss of NMS-1 legacy status.[1214] KU also proposed to add an inspection and processing fee of $100 to Level 1 Interconnections, and to make a customer submitting a Level 1 Interconnection Application responsible for up to $1,000 in costs for an impact study if one is deemed necessary.[1215] KU indicated that it proposed to add the fees for Level 1 interconnection because, while Level 1 interconnections do not require the same level of engineering review as Level 2 interconnections, which the fees currently apply to, the volume of Level 1 interconnection requests has increased significantly.[1216]

[1211] KU's Response to Staff's Second Request, Item 10.

[1212] KU's Response to Staff's Second Request, Item 10.

[1213] Application, Tab 4, page 201.

[1214] KU's Response to Staff's Post-Hearing Request, Items 49–50.

[1215] Application, Tab 4 at 201.

[1216] KU's Response to Staff's Third Request, Item 14.

For Level 2 Interconnections, KU proposed clarifications to the definition of a Level 2 Installation and a revision to require customers to resubmit their application for interconnection if there are any modifications from the initially submitted plan.[1217]

Finally, the conditions for interconnection were updated to ensure compliance with applicable codes, standards, and company-published technical interconnection requirements that are separate from the tariff and KU proposed to remove the application forms from the tariff as they are posted publicly on the Company's website.[1218]

No intervenors provided testimony on these issues. KU proposed many of the same changes to the Interconnection Guidelines in Case No. 2020-00349.[1219] In that case, the Commission denied the proposed revisions and found that they should be addressed in Case No. 2020-00302.[1220] While Case No. 2020-00302 is still an open proceeding, the Commission finds that KU's proposed revisions to the Net Metering Interconnection Guidelines are reasonable and that they should be approved pending the final outcome of Case No. 2020-00302, with the exception of the items discussed below.

As noted above, KU proposed a revision that would cause NMS-1 customers to lose their legacy status as a result of a customer increasing the generation capacity of their facility. KRS 278.466(6), which set up legacy status for NMS-1 customers, is silent as to the impact of material changes to the eligible generating facility on the legacy status of that facility. However, the interconnection and net metering guidelines approved by

[1217] KU's Response to Staff's Second Request, Item 10.

[1218] KU's Response to Staff's Second Request, Item 10.

[1219] Case No. 2020-00349, Application, proposed P.S.C. No. 20, Original Sheet Nos. 108–108.5.

[1220] Case No. 2020-00302, *Investigation of Interconnection and Net Metering Guidelines* (Ky. PSC June 30, 2021), Order at 40.

the Commission in Administrative Case No. 2008-00169, provided that, absent written permission by a utility, increases in generating facility capacity will require a new application for interconnection and net metering.[1221] Consistent with the provisions in Case No. 2008-00169 previously determined to be reasonable, the Commission finds that any modification or installation that materially increases the capacity of an eligible generating facility should be evaluated on the same basis as any other new application. Thus, the Commission further finds that if customers' modification of their eligible generating facility results in a material increase in capacity, then those customers will no longer be eligible to take service under the NMS-1 tariff. The Commission also finds that replacement of eligible generating facilities in the ordinary course that result in only an incidental increase in capacity should not trigger a change in NMS-1 legacy status. These findings are consistent with findings that the Commission has made regarding legacy status for Kentucky Power Company's and Duke Energy Kentucky, Inc.'s NMS-1 customers.[1222]

The Commission finds that the issue of adding fees to Level 1 interconnection requests should be addressed in Case No. 2020-00302 and therefore, should be denied in this proceeding. When the Net Metering Interconnection Guidelines were developed in Administrative Case No. 2008-00169, the Commission specifically excluded the fees

[1221] Administrative Case No. 2008-00169, *Development of Guidelines for Interconnection and Net Metering for Certain Generators with Capacity Up to Thirty Kilowatts* (Ky. PSC Jan. 8, 2009).

[1222] 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 May 14, 2021) at 43–44; Case No. 2023-00413, *Electronic Application of Duke Energy Kentucky, Inc. for an Adjustment to Rider NM Rates and Tariff Approval* (Ky. PSC Oct. 11, 2024) at 28–29.

that KU is proposing to add to Level 1 Interconnection requests.[1223] Addressing whether such fees are now reasonable for Level 1 Interconnection requests is better suited for a proceeding in which all jurisdictional electric utilities and interested parties are involved.

The Commission also finds that KU's proposal to remove the net metering service application forms from its tariff should be denied for many of the same reasons such proposal was denied in Case No. 2020-00349.[1224] Each net metering service application form is just one page. Whether the forms are in the tariff or not, customers could still choose to complete the forms online. Maintaining the application forms in the tariffs ensures that any future revisions to such forms receive the proper Commission review.

Liability Provisions

KU proposed to revise several sections of its tariffs to uniformly limit its liability in all circumstances other than liability resulting from service interruptions to where the Company's gross negligence or willful misconduct is the sole and proximate cause of injury or damage.[1225] For liability resulting from service interruptions, KU proposed to retain and narrow its existing liability to situations in which its willful misconduct of the sole and proximate cause of loss, injury, or damage.[1226] KU argued that the broader exemption from liability for service interruptions is reasonable and necessary to protect

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[1223] Administrative Case No. 2008-00169, *Development of Guidelines for Interconnection and Net Metering for Certain Generators with Capacity Up to Thirty Kilowatts* (Ky. PSC Jan. 8, 2009).

[1224] Case No. 2020-00349, June 30, 2021 Order at 40–41.

[1225] Hornung Direct Testimony at 22.

[1226] Hornung Direct Testimony at 22.

KU and its customers from ruinous liability and that any expansion of its potential liability would result in increased costs to all customers.[1227]

KU stated that liability-limitation clauses are common in many contracts and that unlimited liability would pose a risk to the utility and its customers, whose service and rates could be affected by such liability.[1228] While KU stated that the liability-limitation language in its current tariffs is not inadequate to protect KU and its customers, it indicated that the purpose of the proposed revisions was to increase the uniformity of such provisions throughout the tariff and provide liability protection consistent with Kentucky law.[1229]

KYSEIA argued that the proposed expansion of liability protections should be rejected.[1230] KYSEIA stated that broader exemption from liability would not be beneficial for ratepayers as they would be the ones that suffered the consequences of the Company's negligence that result in service interruptions or injury or damage to persons or property.[1231]

In the Stipulation, the Stipulating Parties agreed that KU would withdraw its requested changes to the liability provisions in its tariffs.[1232]

Having considered the record and being otherwise sufficiently advised, the Commission finds that the Stipulation provision withdrawing the proposed revisions to the

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[1227] Hornung Direct Testimony at 22–23.

[1228] KU's Response to Staff's Second Request, Item 28.

[1229] KU's Response to Staff's Fourth Request, Item 7.

[1230] Hoyle Direct Testimony at 5.

[1231] Hoyle Direct Testimony at 32–33.

[1232] Stipulation, Article 9.12.

liability provisions should be approved. Absent the Stipulation, the Commission finds that KU failed to adequately justify the proposed revisions to the liability provisions in its tariff. KU did not cite any reason as to why its current liability provisions are inadequate or that it has experienced any harm due to the current liability provisions.

Miscellaneous Tariff Changes. KU proposed other changes to its tariff, which can be summarized as updates to improve clarity about the Company's current practices. Unless otherwise stated in this Order, the Commission finds that the proposed changes are reasonable and should be approved.

EXTREMELY HIGH LOAD FACTOR TARIFF

KU proposed the Extremely High Load Factor (EHLF) tariff (Rate EHLF) because, in witness Hornung's words: "[t]he Companies recognize that customers with large demands . . . and very high load factors . . . have sufficiently different service characteristics and potential financial impacts to [KU] and their customers to require a separate rate schedule and terms and conditions of service."[1233] In its original form, Rate EHLF applied to potential new customers which had (1) demand meeting or exceeding 100 MVA; and (2) an expected load factor of at least 85 percent. Rate EHLF is similar to KU's Retail Transmission Service tariff (Rate RTS), which is the tariff generally applicable to other large commercial and industrial customers, but with several key distinctions; detailed below:

- Though Rate EHLF's Basic Service Charge per day and the Energy Charge per kWh are identical to Rate RTS, the Maximum Load Charge per kVA is different. Rate EHLF has a single non-time differentiated demand charge to recover all

[1233] Hornung Direct Testimony at 4.

demand related costs of service. Other large commercial and industrial customers on Rate RTS have time differentiated demand charges (base, intermediate, and peak) each with seasonally differentiated period hours.[1234]

- Further, Rate EHLF requires the monthly billing demand to be the greater of (1) the maximum measured load in the billing period, (2) the highest measured load in the preceding eleven billing periods, or (3) 80 percent of the maximum contract capacity. Rate RTS customers have the same requirements for just the base demand charge—though only a 50 percent of contract capacity provision—and minimum billing demands for the intermediate and peak periods of the greater of (1) the maximum measured load in the billing period or (2) 50 percent of the highest measured load in the preceding eleven billing periods.[1235]

- Rate EHLF requires initial contract terms of not less than fifteen years. Each party to the contract must give at least 60 months written notice to the other party of its intention to discontinue service under the terms of the rate schedule. However, that 60 months notice does not reduce the initial contract term, except through the Exit Fee provision provided for in the Tariff. The Exit Fee provision allows a customer to terminate its contract prior to the expiration of the initial 15 year contract term but requires the terminating customer to pay the Exit Fee which is

[1234] Hornung Direct Testimony at 5. *Also see* Application, Vol. 1 Tab 4 Rate RTS at 30-32 of 204 and Rate EHLF at 33-35 of 204.

[1235] Hornung Direct Testimony at 5. *Also see* Application, Vol. 1 Tab 4 Rate RTS at 30-32 of 204 and Rate EHLF at 33-35 of 204. *Also see* KU's Response to Staff's Second Request, Item 26. A Rate EHLF customer's demand charge will be calculated each billing period using the Maximum Load Charge then in effect, not the Maximum Load Charge that was in effect at the time the customer executed the Electric Service Agreement.

calculated as the "nominal value of the remaining minimum non-fuel revenue over the remaining term." By contrast, Rate RTS requires a one-year contract term with a 90-day termination notice only.[1236]

- Rate EHLF customers or their guarantor must provide collateral in the form of cash or a letter of credit equal to 24 months of the minimum billed amounts at the largest contract capacity value or 12 months of the minimum billed amounts at the largest contract capacity value with a S&P Credit Rating of at least A and a Moody's Credit Rating of at least A2 with cash and cash equivalents on its audited balance sheet of at least 10 times the collateral requirement (enhanced creditworthiness). Rate RTS customers provide a standard deposit of 2/12 of the actual or estimated annual bill.[1237]

KU estimated that a 402 MW Rate EHLF customer, meeting the enhanced creditworthiness requirements, would need to post collateral of more than $100 million at the time of contract signing and would have a 15-year minimum demand charge obligation of about $1.1 billion.[1238] KU explained that the collateral requirement time periods were chosen based on its review of tariffs across the industry. According to KU, the 24-month period covers the minimum billed amounts at the largest contract capacity, which safeguards against revenue loss if the Rate EHLF customer underperforms or terminates

[1236] Hornung Direct Testimony at 6. *Also see* Application, Vol. 1 Tab 4 Rate RTS at 30-32 of 204 and Rate EHLF at 33-35 of 204.

[1237] Hornung Direct Testimony at 6. *Also see* Application, Vol. 1 Tab 4 Rate RTS at 30-32 of 204 and Rate EHLF at 33-35 of 204 and Terms and Conditions Deposits at 177 of 204.

[1238] Hornung Direct Testimony at 7.

the contract early.[1239] Meanwhile, the 12-month period is designed for Rate EHLF customers with strong creditworthiness or lower perceived risk.[1240] KU provided an example of how the Capacity Reduction Fee, which is calculated as the nominal value of the remaining minimum non-fuel revenue change from the original contract capacity over the remaining contract term, would be applied.[1241]

The Attorney General/KIUC noted that the Stipulation and Recommendation filed in Case No. 2025-00045 modified the applicability of the proposed new Rate EHLF tariff to new loads.[1242] The Attorney General/KIUC's expert Mr. Kollen, argued that this is necessary to ensure that, "if an existing load grows and meets the qualifications of the EHLF tariff, that it is not required to sign service agreements for 15 years, assume liabilities for minimum contract payments, or provide collateral necessary to ensure performance of the new loads."[1243]

[1239] KU's Response to Staff's First Request, Item 4. *See also* Application, Vol. 1 Tab 4 Rate EHLF at 34 of 204.

[1240] KU's Response to Staff's First Request, Item 4.

[1241] *See* KU's Response to Staff's Second Request, Item 5 and Application Vol. 1 Tab 4 Rate EHLF at 33 of 204. The Capacity Reduction Fee for a 300 MVA EHLF customer seeking to reduce its contract capacity to 200 MVA by applying the Maximum Load Charge to the 100 MVA contract capacity change for the remaining term of the EHLF contract. The EHLF Maximum Load Charge for a given month is applied on a per-kVA basis where the monthly billing demand for the Maximum Load Charge is the greater of:

1. the maximum measured load in the current billing period, or

2. the highest measured load in the preceding eleven (11) monthly billing periods, or

3. 80% of the contract capacity based on the maximum load expected on the system or on facilities specified by Customer.

KU explained that only items 2 and 3 would be relevant to calculating the Capacity Reduction Fee (and item 2 would be relevant only for at most the first year of the calculation).

[1242] Kollen Corrected Direct Testimony at 96.

[1243] Kollen Corrected Direct Testimony at 96.

Walmart originally argued that data centers present unique challenges to utilities due to the scale and concentration of the energy demand.[1244] That demand could reach thousands of MWs and represent a significant portion of a utility's total demand and pose system planning and cost recovery risks.[1245] Walmart expressed concern for the need to ensure that projected extremely high load factor customer load actually materializes as expected and remains in service for a meaningful period. Additionally, Walmart was concerned and recommended that the Rate EHLF customer load not limit system access to power or crowd out more traditional commercial and industrial customer growth and that fostering a supportive environment for these customers is vital to Kentucky's long term economic health.[1246] Walmart stated that the Rate EHLF tariff addresses the unique risks posed by the customers with demands substantially higher than other customers and that it supports the Rate EHLF tariff, as filed.[1247]

Sierra Club noted that while KU stated that its 100 MVA load size was chosen by doing peer industry review and its own understanding of its resource needs, the tariffs identified by KU either had significantly lower size thresholds (5 to 30 MW) or had meaningful differences in how the utilities with similar size thresholds structured its tariffs.[1248] Sierra Club argued that the Commission should allow a load aggregation provision similar to KU's Green Tariff, but in the absence of that, the threshold for inclusion

[1244] See the Direct Testimony of Lisa V. Perry (Perry Direct Testimony) at 25.

[1245] Perry Direct Testimony at 29.

[1246] Perry Direct Testimony at 29-30.

[1247] Perry Direct Testimony at 30-31.

[1248] See the Direct Testimony of Jeremy I. Fisher (Fisher Direct Testimony) at 8-10; and Table JIF-1 pages 7-8.

in Rate EHLF tariff should be lowered to 25 MW.[1249] Sierra Club took issue with Rate EHLF because the tariff didn't include the customer's load ramp period in addition to KU's 15-year contract period, initially.[1250] While Sierra Club acknowledged that Rate EHLF could include a ramp period, it recommended that KU be required to specify the ramp period explicitly in the tariff.[1251] In addition, Sierra Club opined that a 15-year contract term is too short, with Rate EHLF customers potentially leaving the system well before the end of the depreciable lives of the assets built to serve them; leading to KU's remaining customers bearing the costs of those assets inappropriately.

Sierra Club recommended a 20-year contract term inclusive of a load ramp-up provision.[1252] Due to the absence of a clean energy procurement option in the Rate EHLF tariff, Sierra Club recommended that KU either (1) design a broader version of its Green Tariff for EHLF customers that opens the cap on the scale of renewable energy that can be procured and allows for storage, demand management, and transmission improvements; or (2) modify the Green Tariff provision such that it is available to EHLF customers, opens the cap, and allows for storage, demand management, and transmission improvements.[1253] Sierra Club opined that the size and magnitude of EHLF customers' load relative to KU's total load could have an impact on other customers' rate or the allocation of costs in three ways: additional transmission and network improvement costs, an acceleration of additional generation costs that would not have been incurred

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[1249] Fisher Direct Testimony pages 11-12

[1250] Fisher Direct Testimony at 15.

[1251] Fisher Direct Testimony pages 15-16.

[1252] Fisher Direct Testimony pages 16-17.

[1253] Fisher Direct Testimony page 22.

but for the data centers, and higher energy utilization could affect the appropriateness of the current 6-CP rate allocation methodology.[1254] Sierra Club also recommended that KU be required to file a prospective COS comparison study examining several alternate cost allocation schemes to assess the appropriateness of the 6-CP method to prevent undue cost shifting toward non-EHLF customers and assessing mechanisms of either directly assigning network upgrade costs and generation acceleration costs or proposing an equitable allocation mechanism that prevents cross subsidization.[1255] Finally, Sierra Club recommended that the Commission require that Rate EHLF tariff be fully implemented prior to approving any new infrastructure to meet anticipated data center load.[1256]

The Joint Intervenors argued that a small number of high-load customers are causing KU to expand grid assets and, therefore, those customers should bear the full cost of recovering those investments and take on all the associated risks of stranded assets. Joint Intervenors recommended that a main meter on major developments be the point of measurement and that the MVA threshold in the Rate EHLF should be no greater than 50 MVA.[1257] Also, Joint Intervenors posited that the load factor eligibility threshold should be eliminated because data centers do not always maintain high load factors and may have flexible loads. The Joint Intervenors further recommended requiring minimum load flexibility requirements and that KU should take steps necessary to facilitate EHLF customers delivering on load flexibility commitments.[1258] Additionally, Joint Intervenor

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[1254] Fisher Direct Testimony pages 22-26.

[1255] Fisher Direct Testimony page 27.

[1256] Fisher Direct Testimony pages 29-30.

[1257] *See* the Direct Testimony of James Fine (Fine Direct Testimony) at 46-47.

[1258] Fine Direct Testimony at 46-47.

recommendations included separating the ramp-up period from the 15-year minimum contract term, that the exit fee requirement should be approved, and the collateral requirement should be strengthened to more fully protect ratepayers.[1259]

As presented, the Stipulation, in this case, provides a number of modifications to the original proposed Rate EHLF tariff. First, the proposed minimum contract capacity threshold was reduced from 100 to 50 MVA.[1260] Second, the Stipulation included an agreement that Rate EHLF be modified to clarify that: (a) Rate EHLF applies only to new customers; and (b) if a customer attempts to circumvent the minimum capacity threshold of Rate EHLF by siting smaller facilities, the customer will nonetheless be served under Rate EHLF.[1261] KU also committed to working with Rate EHLF customers "in good faith to reach any necessary agreements to reasonably accommodate such customers' renewable energy goals. Such an agreement could also address the customer's use of distributed energy resources such as demand-side management, energy efficiency, and battery storage."[1262] As part of its commitment, KU agreed to "not place any limitations on the size of the resource considered or brought forward by a customer." KU further agreed, as part of the Stipulation's Renewable Energy Goals section, that supply-side agreements would address system upgrades and other necessary items, including appropriate cost allocation and recovery of associated upgrade costs.[1263]

[1259] Fine Direct Testimony at 47.

[1260] Stipulation, Article 8.1.

[1261] Stipulation, Article 8.1.

[1262] *See* the Stipulation, Article 8.1-8.3 and Stipulation Testimony at 23.

[1263] *See* Stipulation, Article 8.1-8.3.

As the Commission has repeatedly stated recently, there is an undeniable growth in electrical demand for capacity and energy driven by investments in data centers.[1264] While investments in data centers have not been equally distributed among the states, Kentucky has been successful in attracting interest from companies considering locating large, even hyperscale sized, data center facilities in the Commonwealth. Moreover, the Kentucky General Assembly has signaled clearly the Commonwealth's desire to attract data center related investment by expanding tax incentives.[1265] Consequently, as was recognized in KU's recent CPCN application for, among other items, significant base load generating units, utilities and the Commission must address the potential influx of these likely large and electric system impacting facilities expeditiously.[1266] Because these facilities pose unique risks, the Commission believes that new tariff structures such as KU's proposed Rate EHLF are necessary.

These new tariffs, in addition to their potential impact, are largely novel exercises for Kentucky's various electric utilities.[1267] In KU's case, Rate EHLF is its first tariff specifically aimed at these large, high-capacity factor customers. Consequently, the Commission understands that Rate EHLF may continue to evolve as customers begin

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[1264] Case No. 2025-00045, Ky. PSC Oct. 28, 2025 Order at 35-36. *See also* Case No. 2025-00140, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. to Establish a New Tariff for Data Center Power* (Ky. PSC Oct. 30, 2025) Order at 15-16.

[1265] KRS 154.20-220(17).

[1266] Case No. 2025-00045. Oct. 28, 2025 Order at 36-37.

[1267] *See also* Case No. 2025-00140, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. to Establish a New Tariff for Data Center Power* (Ky. PSC Oct. 30, 2025); Case No. 2024-00354, *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 Oct. 2, 2025) Order.

taking service under the tariff, especially considering the continuing discussions and differing positions taken by parties in this case.

In considering the proposed Stipulation provisions related to rate EHLF, the Commission recognizes the tension created between attracting companies to the Commonwealth and protecting KU's customer base from incurring additional costs because of the necessary system upgrades to serve those rate EHLF customers.[1268] The Commission is generally pleased with the agreed-on terms in the proposed Stipulation related to Rate EHLF. In particular, the Commission approves of the reduction from a 100 MVA contract capacity threshold to greater than 50 MVA threshold because it is more protective of current KU ratepayers by broadening the potential customer base required to taking service under Rate EHLF for customers who, at 50 MVA, would nonetheless be enormous energy and capacity consumers utilizing any regular measure.

Additionally, the Stipulation's inclusion of renewable energy commitments is reasonable. As KU acknowledged in its Stipulation testimony, companies may, for their own business reasons, make renewable energy commitments.[1269] It is reasonable to assume that those companies will seek to do business with organizations who can meet their needs in terms of energy and capacity, but also with regard to supply-side resource

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[1268] *See i.e.* Kollen Corrected Direct Testimony at 97 as an example of this sentiment which states "[t]he new EHLF tariff provides the Companies with a standardized form of ratemaking recovery for the costs to serve new significant loads with extremely high load factor while ensuring there are necessary safeguards to protect existing customers."

[1269] Stipulation Testimony at 18. However, the Commission reiterates its position that "special contracts entered into to promote corporate sustainability goals should ensure that non-participating customers are no worse off than if the special contracts for renewable energy did not exist. Non-participating customers must not bear additional costs from a jurisdictional utility's actions in attempting to meet a corporation's own self-imposed sustainability goal[s]" Case No. 2020-00016, *Electronic Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source Under Green Tariff Option #3* (Ky. PSC May 8, 2020), Order at 17.

preferences. This provision is therefore a useful economic development tool that conveys that Kentucky is open for business and the signal is stronger if it is included explicitly in Rate EHLF. Consequently, the Commission finds that KU should include KU's renewable energy commitments from Article 8.3 of the Stipulation in the Rate EHLF tariff.

Turning to the remainder of the proposed stipulation agreements related to Rate EHLF, the Commission agrees that the tariff should include language clarifying its application to new customers only. Additionally, the Commission agrees that KU should include language addressing the potential that customers may attempt to circumvent the minimum capacity threshold by siting a number of smaller facilities instead of a single, qualifying facility. However, the Commission is concerned that the language in Article 8.2(B) is not sufficiently clear. The tariff language should clearly state that KU has the authority to aggregate, for the purpose of accurately evaluating the actual minimum capacity threshold of a customer or facility and require the customer(s) to take service under Rate EHLF when reasonable.

Finally, the Commission finds, consistent with its final Order in KU's recent CPCN application, that KU is required to file all Rate EHLF electric service agreements with the Commission.[1270] This provision was agreed to by the parties in that case, and the Commission believes it is crucial in order to provide adequate necessary oversight of these agreements.

[1270] Case No. 2025-00045, Oct. 28, 2025 Order at 162.

OTHER ISSUES

Request for Relief from Annual RTO Membership Study Filing Requirement

KU requested relief from its annual regional transmission organization (RTO) membership study filing requirement, and to file the request triennially with each IRP.[1271] In Case No. 2018-00294, the Commission found that KU should continue to separately evaluate and assess the benefits and costs associated with membership in a RTO, and that KU should update these studies annually and file such updates with the Commission as part of its annual report.[1272] KU stated that conducting the RTO membership study is a significant undertaking, and it is best conducted in the context of the global planning effort of an IRP.[1273] The Stipulation recommended approval of KU's request for relief through the catch-all provision filed as an amendment.[1274]

Having considered the record and being otherwise sufficiently advised, the Commission finds that KU's request should be approved consistent with the Stipulation. The Commission agrees that filing this study in the context of the IRP is a reasonable place to explore RTO membership.

LG&E and KU Energy, LLC Legal Merger Assessment

On October 17, 2017, PPL Corporation, PPL Subsidiary Holdings, LLC, PPL Energy Holdings, LLC, LG&E and KU Energy LLC, LG&E, and KU submitted a joint

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[1271] Application at 15.

[1272] Case No. 2018-00294, *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates* (Ky. PSC Apr. 30, 2019), Order at 29-30.

[1273] Application at 16.

[1274] Amended Stipulation, Article 11.1.

application requesting Commission approval of a corporate reorganization.[1275] On April 4, 2018, the Commission ordered "…LG&E and KU to develop an internal study to fully evaluate and quantify the costs and benefits associated with a potential merger of the two utilities."[1276] On August 8, 2018, an internal study was conducted.[1277] The study concluded that financial savings were too small and outweighed by one-time merger costs.[1278] On April 30, 2019, the Commission found "… that [LG&E/KU] should update these studies annually and file such updates with the Commission as part of [the] annual report.[1279] Additionally, the Commission found that "[a]s part of its annual report, [LG&E/KU] shall file updates to its RTO membership study and potential legal merger study."[1280]

On March 31, 2020,[1281] and on March 31, 2021,[1282] annual internal studies were filed with the Commission. On June 30, 2021, in Case Nos. 2020-00349 and 2020-00350,

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[1275] 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*, Case No. 2017-00415 (Ky. PSC Oct. 17, 2017), Order.

[1276] Case No. 2017-00415, Apr 4, 2018 Order at 8-9.

[1277] LG&E and KU Potential Legal Merger of Utilities Internal Study (filed Aug. 8, 2018) (Aug. 8, 2018, Study).

[1278] Aug. 8, 2018, Study at 2.

[1279] Case No. 2018-00294, *Electronic Application of Kentucky Utilities Company for an Adjustment of its Electric Rates* Case (Ky. PSC Apr. 30, 2019), Order at_30, 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), Order at 33.

[1280] *Case* No. 2018-00294, Apr. 30, 2019, Order at 31, and Case No, 2018-00295, Apr. 30, 2019 Order at 34.

[1281] LG&E and KU Potential Legal Merger of Utilities Internal Study (filed Mar. 31, 2020).

[1282] LG&E and KU Potential Legal Merger of Utilities Internal Study (filed Mar. 31, 2021).

the Commission stated that it "... is not convinced that [LG&E/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."[1283] The Commission went on to state it "…expects future merger studies to reflect an unbiased review of the benefits and costs of a legal merger, and we further expect [LG&E/KU] to address those qualitative risks continually identified as a hurdle to legal merger."[1284]

On March 31, 2022, LG&E/KU submitted a Legal Merger Assessment prepared by PricewaterhouseCoopers Advisory Services LLC (PWC).[1285] PWC conducted interviews with management to understand LG&E/KU's activities, organizational structure, and how services are planned and executed.[1286] These interviews were supplemented with follow-up discussions to clarify issues related to the potential legal merger.[1287] PWC reviewed internal merger studies and concluded that while LG&E/KU already operates on an integrated basis, additional cost savings from a legal merger would mainly come from simplifying the legal entity structure and reducing administrative costs.[1288] PWC concluded that the one-time incremental costs of a legal merger would be $22.1 million and the estimated annual net savings would be $2.3 million and that future tax and

[1283] Case No. 2020-00349, June 30, 2021 Order at 59, Case No. 2020-00350, June 21, 2021 Order at 63-64.

[1284] Case No. 2020-00349, June 30, 2021 Order at 59, Case No. 2020-00350, June 30, 2021 Order at 63-64.

[1285] LG&E/KU Legal Merger Assessment (filed Mar. 31, 2022) (Mar. 31, 2022 Assessment).

[1286] Mar. 31, 2022 Assessment at 4.

[1287] Mar. 31, 2022 Assessment at 4.

[1288] Mar. 31, 2022 Assessment at 4.

financial considerations from a merger would not result in material financial impacts.[1289] PWC also concluded that it would result in complexities and risks arising from the need for new financial instructions and securing IRS private letter rulings.[1290]

In a post case filing in Case Nos. 2018-00294 and 2018-00295, on March 31, 2023, LG&E/KU filed a Legal Merger Study[1291] in addition to a joint motion requesting relief from an annual reporting requirement.[1292] On August 22, 2023, the Commission found that it "…remains concerned that LG&E/KU is not fully considering the impact its legal status has on others and savings from a legal merger."[1293] The Commission went on to find that PWC essentially "…overlooks the impact on the duplication of costs to ratepayers and stress on regulators' resources because revenue requirement filings and supporting financial data, data request responses, and resulting rate schedules are unique to each of the two utilities and thus remain the equivalent of two general rate cases."[1294] The Commission also found that it was not persuaded that LG&E/KU established good cause to cease filing legal merger study updates because LG&E/KU has not addressed issues raised by the Commission and has not filed an unbiased review of the benefits and costs.[1295] However, the Commission concluded based on efficiency and the improved

[1289] Mar. 31, 2022 Assessment at 4.

[1290] Mar. 31, 2022 Assessment at 4.

[1291] LG&E and KU Potential Legal Merger of Utilities Internal Study (filed Mar. 31, 2023) (Mar. 31, 2023, Assessment).

[1292] Case Nos. 2018-00294 and 2018-00295, LG&E/KU's Motion for Relief (filed Mar. 31, 2023), unnumbered pages 1–2.

[1293] Case Nos. 2018-00294 and 2018-00295, Aug. 22, 2023 Order at 3.

[1294] Case Nos. 2018-00294 and 2018-00295, Aug. 22, 2023 Order at 4.

[1295] Case Nos. 2018-00294 and 2018-00295, Aug. 22, 2023 Order at 5.

quality of the analysis, LG&E/KU should cease filing annual updates and, instead, file legal merger study updates that fully consider all issues raised by the Commission as part of an application for a general rate adjustment filed pursuant to KRS 278.190 and 807 KAR 5:001, Section 16.[1296]

In its application, KU asked for a determination that the LG&E and KU Energy LLC Legal Merger Assessment presents a reasonable plan for the legal merger of LG&E and KU, subject to obtaining the requisite regulatory approvals.[1297] KU stated the desire to move toward a potential merger.[1298] The LG&E and KU Energy LLC Legal Merger Assessment Possible Legal Merger of LG&E and KU – Update,[1299] found that although direct financial savings are minimal because the Companies already operate as one, a legal merger could create meaningful regulatory efficiencies by eliminating duplicate filings, rate cases, and tariffs.[1300] The study found that the strongest reason to proceed now is that upcoming IT system upgrades could avoid the $17–20 million in reconfiguration costs if designed for a single merged utility.[1301] As a result, despite limited cost savings, the companies recommended continuing to pursue the merger, subject to further review and regulatory approval. Witness Conroy stated at the hearing that he does not believe that the stay out would be affected by a merger.[1302] He further explained

[1296] Case Nos. 2018-00294 and 2018-00295, Aug. 22, 2023 Order at 5.

[1297] Application at 19.

[1298] Garett Direct Testimony at 5-6.

[1299] LG&E and KU Energy LLC Legal Merger Assessment Possible Legal Merger of LG&E and KU – Update (Exhibit CMG-1 dated May 15, 2025) (Exhibit CMG-1).

[1300] Garrett Direct Testimony, Exhibit CMG-1 at 3-4.

[1301] Garrett Direct Testimony, Exhibit CMG-1 at 3-4.

[1302] HVT of the Nov. 4, 2025 Hearing (Cross of Robert Conroy) at 10:27:31–10:27:48.

that they were not asking for specific approval on the merger, and the Companies would come forward in a future proceeding if they decide to move forward with the merger.[1303]

The Legal Merger Assessment was not explicitly addressed in the Stipulation but was agreed to by the Stipulating Parties under the catch-all provision.[1304]

On December 30, 2025, KU filed a joint update stating in pertinent part "...that now is the time to proceed, and the [LG&E/KU] plan to design the new ERP system assuming LG&E and KU will merge in early 2027. [LG&E/KU] expect to file necessary applications for merger approval in the first quarter of 2026 with this Commission…"[1305]

Having considered the record and being otherwise sufficiently advised, the Commission finds that KU has complied with the directives related to the merger assessment from the final Order in Case No. 2020-00349.

<u>Request for Relief from Merger Commitment Regarding LG&E and KU Foundation</u>

KU proposed to modify Commitment No. 55 of Appendix C to the September 30, 2020 Order in Case No. 2010-00204[1306] to allow consolidation of the existing LG&E and KU Foundation Inc. into the existing PPL Foundation.[1307] Commitment No. 55 of Appendix C states that "PPL, E.ON US, LGBE, and KU commit that the E.ON US Foundation shall remain an asset of E.ON US, and that the E.ON US Foundation's current

[1303] HVT of the Nov. 4, 2025 Hearing (Cross of Robert Conroy) 10:27:49-10:28:20.

[1304] Amended Stipulation, Article 11.1.

[1305] Joint Update of KU and LG&E (filed Dec. 30, 2025) at unnumbered page 2.

[1306] Case No. 2010-00304, *Electronic Joint Application of PPL Corporation, E. on AG, E. On US Investments Corp., E. On U.S. LLC, Louisville Gas and Electric Company, and Kentucky Utilities Company for Approval of an Acquisition of Ownership and Control of Utilities.*

[1307] Application at 17.

charitable purpose shall remain unchanged."[1308] KU stated that consolidating the two foundations, by merger or other structure, will reduce trustee fees and allow for more expedient accounting, tax, legal, and other back-office functions.[1309] The sole member of LG&E and KU Foundation is currently LKE (formerly known as E.ON U.S. LLC).[1310] LG&E/KU stated that LG&E and KU expect to continue supporting grant making programs and other programs initiated by LG&E and KU in the past, with support from the PPL Foundation.[1311] LG&E/KU stated that the combined foundation will work to avoid any confusion for grant recipients and community partners through active communications to local communities and charities describing the consolidation and related transition matters.[1312]

Although the Stipulation does not directly address the issue, it recommended approval of this provision through the catch-all provision filed as an amendment.[1313]

Having considered the record and being otherwise sufficiently advised, the Commission finds the request for relief from Commitment No. 55 of Appendix C to the September 30, 2020 Order in Case No. 2010-00204 is reasonable and should be approved.

[1308] Case No. 2010-00204, Sept. 30, 2010 Order, Appendix C at 13.

[1309] Garrett Direct Testimony at 6.

[1310] Garrett Direct Testimony at 6.

[1311] Garrett Direct Testimony at 7.

[1312] Garrett Direct Testimony at 7-8.

[1313] Amended Stipulation, Article 11.1.

Request for Deviation from 807 KAR 5:041, Section 7 Voltmeter Requirements

KU requested a deviation from the requirements of 807 KAR 5:041, Section 7 that would permit it to satisfy the regulation's voltage survey and 3-year recordkeeping requirements using available AMI data instead of portable or recording voltmeters, and excuse it from the requirements in Section 7(2) pertaining to maintenance and recordkeeping for voltmeters.[1314]

807 KAR 5:041, Section 7 states as follows:

> (1)Every utility shall have two (2) or more portable indicating voltmeters and two (2) or more recording or graphic voltmeters of type and capacity suited to the voltage supplied. Every utility shall make a sufficient number of voltage surveys to indicate the service furnished from each center of distribution. To satisfy the commission of its compliance with voltage requirements, each utility shall keep at least one (1) of these instruments in continuous service at some representative point on its system. All records of the most recent voltage surveys taken within the last three (3) calendar years shall be available for inspection by the utility's customers and commission staff.
>
> (2) Each graphic recording voltmeter shall be checked with a working standard indicating voltmeter when it is placed in operation and when it is removed, or periodically if the instrument is in a permanent location. Notations on each chart shall indicate beginning time and date of registration and when the chart was removed, as well as the point where voltage was taken, and results of the check with indicating voltmeter.

KU explained that it currently complies with this regulation by maintaining 160 recording voltmeters that are utilized at representative points in the system.[1315] KU stated that the

[1314] Application at 17.

[1315] Waldrab Direct Testimony at 34-35.

annual cost to perform these voltage surveys is estimated to be $100,000.[1316] KU stated that the AMI meters deployed by KU are capable of capturing and transmitting voltage data that satisfies the surveying requirements of the regulation and the AMI meters record voltage for every customer every 15 minutes.[1317] KU stated that the voltmeters required by 807 KAR 5:041, Section 7 are redundant of AMI and add cost.[1318] The Stipulation recommended approval of this provision through the catch-all provision filed as an amendment.[1319]

On June 9, 2025, the Commission opened an administrative case to consider how to address regulatory deviations with advanced metering infrastructure (AMI) and automated meter reading (AMR) technology as they relate to voltage surveys outlined in 807 KAR 5:041, Section 7, to which KU is a party.[1320] The Commission finds that KU's request to deviate from 807 KAR 5:041, Section 7, consistent with the Stipulation, is approved, subject to any findings in Case No. 2025-00131.

Additional Joint Intervenors' Recommendations

Along with the recommendations discussed above in individual sections, the Joint Intervenors made several other recommendations. Those recommendations are discussed below.

[1316] Waldrab Direct Testimony at 35.

[1317] Waldrab Direct Testimony at 35.

[1318] Waldrab Direct Testimony at 35.

[1319] Amended Stipulation, Article 11.1.

[1320] Case No. 2025-00131, *Electronic Investigation to Consider Deviation of Regulation 807 KAR 5:041, Section 7, Voltage Surveys and Records*.

Time-of-Day (TOD) Rate Pilot Project. The Joint Intervenors recommended that KU implement a two-year pilot project focusing on enlisting community-based organizations in the provision of outreach for KU's TOD rates, and that the pilot project be funded at a level of $200,000 annually for two years.[1321] The recommended program would use Low Income Home Energy Assistance Program (LIHEAP) eligibility to further extend bill reduction efforts without the need for federal funding.[1322]

KU stated that a pilot program is not necessary as it already maintains strong relationships with low-income assistance agencies and regularly meets with them to share information about available programs.[1323]

The Commission finds that, based on the information provided, this program should not be implemented. The Commission notes KU might want to have further discussions with stakeholders related to this proposal as part of its demand side management portfolio. However, in this case, there is insufficient evidence to require KU to implement the pilot program.

Late Payment Fee Exemptions. KU currently waives late payment fees for residential customers who receive a pledge or notice of low-income energy assistance from an authorized agency for the bill for which the pledge or notice is received. KU also waives the late payment fees for the next 11 months following receipt of a pledge or notice of low-income energy assistance.[1324] The Joint Intervenors recommended that the policy

[1321] Colton Direct Testimony at 44.

[1322] Colton Direct Testimony at 45.

[1323] Montgomery Rebuttal Testimony at page 6.

[1324] Colton Direct Testimony at 45-46.

be revised to exempt a customer from the late payment fee if the customer has received an energy assistance grant from an authorized agency within the current or immediately preceding two LIHEAP program years.[1325] The Joint Intervenors also recommended that customers should be exempt from the late payment fee if they can document participation in a public assistance program with income eligibility that is consistent with LIHEAP eligibility.[1326]

KU stated that it already waives the late payment fee for any customer who receives assistance from LIHEAP or any other assistance program that works with the Company.[1327] KU explained that its policy already accounts for ongoing financial hardship by providing a full year of late payment fee waivers following receipt of assistance.[1328]

The Commission finds that the Joint Intervenors' recommendation regarding the waiver of late payment fees should be rejected. As KU stated, it already waives such fees for customers who receive assistance from programs that work with KU, and it waives the fees for the next 11 months following the pledge or notice of assistance.

Disconnect/Reconnect Fee Exemptions. The Joint Intervenors recommended that KU exempt low-income customers from paying disconnect/reconnect fees as such fees serve as an impediment to low-income customers reconnecting to the system.[1329]

KU stated that for customers with AMI meters, which includes the vast majority of residential customers, there is no fee associated with disconnection or reconnection of

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[1325] Colton Direct Testimony at 46.

[1326] Colton Direct Testimony at 46.

[1327] Montgomery Rebuttal Testimony at 7.

[1328] Montgomery Rebuttal Testimony at 8.

[1329] Colton Direct Testimony at 49.

service.[1330] For those without AMI meters, the disconnect/reconnect fees only recover the costs of providing the service and are not punitive.[1331]

The Commission finds that the Joint Intervenors recommendation regarding the waiver or disconnect/reconnect fees should be rejected. As KU stated, the vast majority of its residential customers have AMI meters and thus are not subject to disconnect/reconnect fees. For those without AMI meters, KU should be able to recover the incremental costs of disconnecting and reconnecting such customers.

Availability of Residential Time-of-Day Rates. The Joint Intervenors recommended that KU review the accounts of customers receiving energy assistance benefits and if such customers would receive a bill savings of no less than $50 via a switch to the Time-of-Day rate, then such customers should be switched to the Time-of-Day rate unless they chose to opt-out of the switch.[1332] For those that do not opt-out, the Joint Intervenors recommended that the optimal rate should be guaranteed and that after 12 months, the rate switch should be compared to the basic residential tariffed rate and if the basic rate would have provided more savings, the customer should be switched back to the basic rate with the difference between the two rates being refunded.[1333]

KU noted that its Residential Time-of-Day rates are optional rates and stated that customers are best positioned to decide whether a Time-of-Day rate is right for them.[1334]

[1330] Montgomery Rebuttal Testimony at 8.

[1331] Montgomery Rebuttal Testimony at 9.

[1332] Colton Direct Testimony at 51- 52.

[1333] Colton Direct Testimony at 52.

[1334] Montgomery Rebuttal Testimony at 5.

KU stated that guaranteeing the optimal rate would create a precedent for the utility to assume financial responsibility for customer rate choices.[1335]

The Commission finds that the Joint Intervenors' recommendation regarding the availability of residential time-of-day rates should be rejected. Customers have the choice of which rate schedule they wish to be served under and allowing KU the power to change that could lead to unintended consequences.

Customer Segmentation Study. The Joint Intervenors recommended that KU should be directed to, in consultation with the Joint Intervenors and other interested stakeholders, retain an independent firm to prepare, no later than December 31, 2026, a customer segmentation study that examines, disaggregated by socioeconomic status: (1) patterns of nonpayment; (2) characteristics of nonpayers; (3) predictors of nonpayment; (4) strategies to reduce nonpayment; and (5) early indicators of nonpayment.[1336]

KU stated that it does not believe that segmenting customers by socio-economic status would provide any actionable insights or benefits, that it already has systems in place to manage arrearages and support customers in need, and that conducting such a study would impose additional costs on KU that would ultimately be passed on to the customers.[1337]

The Commission finds that there is insufficient evidence to require KU to undertake the proposed study. As KU noted, the costs would be passed on to the ratepayers with an unclear intended use or benefit of the data or reasoning . Further, Joint Intervenors

[1335] Montgomery Rebuttal Testimony at 6.

[1336] Colton Direct Testimony at 55 through 56.

[1337] Montgomery Rebuttal Testimony at 12.

provided no indication how this data, specific to an electric utility, would differ from broader consumer data for the same geophysical area. Finally, the Commission is concerned that data collection of this magnitude may represent a significant violation of privacy with regard to KU customers. Voluntary customer participation in a third party study may provide useful information, but customers would be right to suspect a request for this type of information from a service provider with no competition for service.

Arrearage Management Program. The Joint Intervenors recommended that KU be directed to implement a means-tested Arrearage Management Program (AMP).[1338] The Joint Intervenors explained that an AMP is designed to reduce pre-program arrears over an extended period of time in exchange for a customer's continuing payment of bills for current service.[1339] The Joint Intervenors recommended that the AMP should be designed to forgive arrears over a 24-month period, with arrearage credits earned on a monthly basis.[1340] Joint Intervenors recommended that the cost of the AMP should be collected through a true-up surcharge.[1341]

KU stated that the AMP would reward customers for having large accrued arrearages and then making minimal payments to receive a substantial amount of debt forgiveness and also incentivize customers to delay payment or accumulate arrears in order to qualify for forgiveness.[1342] KU argued that the program would shift costs to other customers, thus violating the filed rate doctrine which does not allow for utilities to

[1338] Colton Direct Testimony at 68.

[1339] Colton Direct Testimony at 68.

[1340] Colton Direct Testimony at 69.

[1341] Colton Direct Testimony at 75.

[1342] Montgomery Rebuttal Testimony at 13.

discriminate amongst customers or offer preferential treatment outside the approved tariffs.[1343]

The Commission finds that the Joint Intervenors' recommendation that KU establish an AMP should be rejected. While the idea of such a plan is noble, as KU noted, such a program would shift costs to other customers and provide preferential treatment to a subclass of customers.

<u>Solarization Plan for Low-Income Households.</u> The Joint Intervenors recommended that KU should be directed to work with stakeholders to develop a ten-year solarization plan directed toward low-income households and that the plan be filed with the Commission no later than December 31, 2026 and be updated biannually thereafter.[1344]

KU argued that it believes that the most cost-effective way to deliver solar benefits to all customers is through utility-scale solar investments and existing programs like the Solar Share Program.[1345] KU also stated that creating the plan and updating it biannually will require significant investments that will have to be borne by all customers.[1346]

The Commission finds that there is insufficient evidence to require such a plan at this time. As KU noted, it has a Solar Share Program. In addition, the cost of this program would be borne by all ratepayers.

[1343] Montgomery Rebuttal Testimony at 13.

[1344] Colton Direct Testimony at 88-89.

[1345] Montgomery Rebuttal Testimony at 13-14.

[1346] Montgomery Rebuttal Testimony at 14.

Transportation Electrification. The Joint Intervenors recommended that KU explicitly track the costs of its promotion of transportation electrification and that KU be required to develop a program of fleet and public transportation incentives situated in or that primarily service Environmental Justice communities.[1347]

KU stated that it already supports transportation electrification in a way that is beneficial to all customers through a multifaceted strategy including public charging infrastructure, hosted station programs, and the Optimized Electric Vehicle Charging Program.[1348] In regards to site selection for charging stations, KU stated that it already considers proximity to major roadways, availability of amenities, and opportunities to locate within low-income communities.[1349]

The Commission finds that there is insufficient evidence to require KU to undertake such incentives. Once again, there is a cost that would be borne by all ratepayers even though Joint Intervenors' proposal is directed at a sub-set of customers.

Performance-Based Ratemaking. The Joint Intervenors recommended that the Commission adopt a Performance-Based Ratemaking system that measures the Company's performance with respect to its credit and collection outcomes.[1350] The outcome metrics recommended by the Joint Intervenors were: (1) an increase in the enrollment of low-income customers in LIHEAP and WeCare; (2) a reduction of 15 percent each year for three years in the absolute number of defaulted residential deferred

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[1347] Colton Direct Testimony at 91.

[1348] Montgomery Rebuttal Testimony at 14-15.

[1349] Montgomery Rebuttal Testimony at 15.

[1350] Colton Direct Testimony at 92-94.

payment arrangements; (3) a reduction by 15 percent each year for three years in the absolute number of residential nonpayment disconnections; (4) a reduction by 15 percent each year for three years in the number of residential customers who have, since April 1 of a given year, had their service disconnected for nonpayment and who, as of November 1 of that year, remained in their home with service not yet reconnected; (5) a reduction each year for three years in the average monthly arrears measured in bills behind, for identified low-income customers not on agreement.[1351] The Joint Intervenors recommended that failure to achieve the proposed collection outcomes should result in sanctions determined as follows: (1) dollar amount equivalent to 15 basis points ROE reduction for noncompliance with a single improvement goal; and (2) dollar amount equivalent to 25 basis points ROE reduction for noncompliance with multiple improvement goals.[1352] The Joint Intervenors recommended that any resulting penalty amount would be deferred as a regulatory liability to be refunded to customers in LG&E/KU's next base rate case.[1353]

KU stated that the Commission has held for more than 20 years that it lacks authority to distinguish among customers based on income for base rate purposes and that it cannot address affordability as a means of distinguishing among customers for rate purposes.[1354] More importantly, KU stated that the Kentucky Supreme Court has stated

[1351] Colton Direct Testimony at 96-98.

[1352] Colton Direct Testimony at 100.

[1353] Colton Direct Testimony at 100.

[1354] Conroy Rebuttal Testimony at 16-17.

that the Commission cannot reduce ROEs or use any other means of reducing rates to penalize utilities for service or management performance.[1355]

The Commission finds that the Joint Intervenors' proposal should be rejected. The Commission agrees that it cannot distinguish among classes for ratemaking purposes to address affordability. Further, calling a program "Performance-Based Ratemaking" that only penalizes the utility is a disingenuous misnomer that attempts to disguise punishing the utility for not meeting extended goals aimed at low-income customer assistance beyond KU's current efforts.

WeCare Spending. The Joint Intervenors recommended that KU increase their annual WeCare spending to serve the annual number of households included in their most recent Energy Efficiency Plan and that to the extent increased outreach is required to achieve the increase in spending, WeCare should be incorporated into the other recommended outreach proposals.[1356] The Joint Intervenors also recommended that if actual spending falls short of the budgeted expenditures, the excess budget should be carried over into the next fiscal year.[1357] Finally, the Joint Intervenors recommended that within 12 months of a final order in this proceeding, KU should file an amended WeCare plan with the Commission with an amended budget designed to serve no fewer than 50 percent of the eligible population over no more than a 15 year period.[1358]

[1355] Conroy Rebuttal Testimony at 18.

[1356] Colton Direct Testimony at 118.

[1357] Colton Direct Testimony at 118.

[1358] Colton Direct Testimony at 119.

KU stated that it made revisions to its DSM-EE Plan less than two years ago and that the current plan represents KU's most significant investment in DSM-EE over the history of KU offering such plans.[1359] KU did indicate that after it observed a decline in the single family WeCare participation, it engaged with the Kentucky Housing Corporation (KHC) to understand the trend.[1360] KHC informed KU that, due to funding received through the Infrastructure Investment and Jobs Act, it was able to meet the needs of many low-income clients directly without having to refer them to WeCare.[1361] While KU indicated single family participation in WeCare was down, it did state that the multi-family expansion has allowed them to serve a greater number of households living in rental complexes, which has allowed KU to remain on track to meet the WeCare program objectives of its DSM-EE Plan.[1362]

The Commission finds that the Joint Intervenor's recommendations regarding the WeCare Plan should be rejected. As KU noted, it recently updated its DSM-EE plan, and the Commission approved the updated plan. In addition, revisions to the WeCare Plan would be better suited to a case exclusively dealing with DSM-EE issues. The Commission encourages KU to continue to study and expand its DSM-EE programs.

SUMMARY

The Commission accepts the Stipulation reached by the Signing Parties subject to certain modifications contained herein. The modifications were necessary to ensure fair,

[1359] Montgomery Rebuttal Testimony at 15.

[1360] Montgomery Rebuttal Testimony at 16.

[1361] Montgomery Rebuttal Testimony at 16.

[1362] Montgomery Rebuttal Testimony at 16.

just and reasonable rates. The effect of the Commission's adjustments and modifications to the Stipulation is a total revenue requirement increase of $128,483,032, which includes the authorized ROE of 9.775 percent. This reflects a $97,638,815 decrease of KU's requested revenue requirement increase of $226,315,920[1363] and an approximate $3.5 million decrease from the stipulated revenue requirement increase. The result of the Commission's approved increase for an average residential customer using 1,085 kWh a month is an increase of $8.73 per month, or 6.54 percent, from $133.57 to $142.30.

KU proposed several new adjustment clauses both in its Application and its Stipulation. Each adjustment clause is shown as a line-item on a customer's bill and would result in the potential for increased rates, without separate customer notice, during the proposed stay-out period. To mitigate the potential for large rate impacts, the Commission approved with modifications the GCR (renamed to PGR) but denied the Adjustment Clause RPPA and Adjustment Clause SM. The authorized ROE for recovery of capital riders including the PGR is 9.675 percent.

The Commission approved a modified version of the deferral mechanism for storm damages, OPEB expense, approved a regulatory asset for software implementation costs and amortized the deferral over the life of the underlying software, but denied regulatory asset treatment related to vegetation management and de-pancaking expense. The Commission also approved amortization periods related to recovery of AMI implementation, storm damages regulatory assets, and the Glendale Megasite regulatory asset.

[1363] KU requested an increase of $226,121,847 but calculated a revenue deficiency of $226,315,920.

The Commission approved KU's requests related to the SQF and LQF avoided energy rates. The Commission denied KU's request for a zero avoided capacity cost for SQF and LQF, instead calculating the avoided capacity rates consistent with past rate cases. The Commission denied KU's request for updated language to the availability section of the tariff. The Commission also approved the Stipulation regarding the NMS-2 tariff, which keeps the avoided cost credit at its current level. However, for each avoided cost the Commission described how KU should approach the calculation in its next NMS-2 case. The Commission also approved the Rate PSA rates set forth in the Stipulation with modifications.

The Commission approved a majority of the tariff provisions requested by KU. However, the Commission approved with modifications the provision related to legacy status of Rate GS and Rate PS legacy customers, Rider RAR, paperless billing, pre-pay program, and net-metering interconnection guidelines. The Commission approved KU's proposal to make paperless billing the default billing method for new customers, but denied the same for current customers. The Commission approved KU's proposal to make paperless billing the default billing method for new customers, but denied the same for current customers. The Commission also granted KU's request for relief from annual RTO membership study filing requirement; confirmed that KU has complied with the directives related to the merger assessment; granted relief from merger commitment regarding LG&E and KU Foundation; and granted the request for deviation for voltmeter requirements.

IT IS THEREFORE ORDERED that:

1. The rates and charges proposed by KU in its application are denied unless otherwise discussed below.

2. The Stipulation, attached to this Order as Appendix A (without exhibits) and the Amended Stipulation, attached to this Order as Appendix B, is approved with modifications.

3. The rates and charges as set forth in Appendix D and E are approved as fair, just and reasonable rates for KU, and these rates and charges are approved for service on and after the issuance of this Order.

4. The depreciation study submitted by KU is accepted.

5. The Stipulation provisions regarding previously approved regulatory assets and select future expenses related to storm damage restoration are approved in part and denied in part.

6. KU's request for automatic deferred account for storm damage amounts above or below base rates is denied.

7. KU may defer storm damage restoration costs for major storms that exceed $2 million and are above the amounts included in base rates without prior Commission approval. A major storm would qualify under Institute of Electrical and Electronics Engineers (IEEE) Standard 1366, a Major Event Day. LG&E is approved to amortize these regulatory assets over 5 years.

8. The Stipulation provision regarding deferral accounting of vegetation management expenses is denied.

9. KU's proposal to defer software implementation costs through December 31, 2026 and to amortize those costs over the lives of the underlying software is approved.

10. The Stipulation provision regarding pension and OPEB expenses is granted, in part, and denied, in part. The request for deferral accounting related to pension and OPEB expenses is approved. The provision to reduce the base rate amount is denied.

11. KU's proposal for a regulatory asset related to MMD expenses is denied.

12. LG&E's proposal to amortize AMI implementation regulatory assets and liabilities over 15 and 5 years, respectively, is approved.

13. KU shall continue to file the quarterly reports and annual reports related to AMI as ordered in Case No. 2020-00349 until such time as AMI is completely implemented.

14. KU shall include information and testimony about the AMI implementation and integration in its next base rate filing including addressing such items as the effect of the reduction in disconnect and reconnect fees, conservation voltage reduction, electric distribution operations cost reductions and the impact or effectiveness of the customer engagement program.

15. KU's proposal to amortize its current regulatory assets for storm damage over 5 years is approved.

16. KU's proposal to amortize its current regulatory assets for storm damage over 5 years is approved.

17. KU's proposal to amortize its current regulatory assets related to the Glendale Megasite over five years is approved.

18. KU shall include information and testimony about the AMI implementation and integration in its next base rate filing including addressing such items as the effect of

the reduction in disconnect and reconnect fees, conservation voltage reduction, electric distribution operations cost reductions and the impact or effectiveness of the customer engagement program.

19. The proposed Adjustment Clause RPPA is denied.

20. The Stipulation provision regarding Adjustment Clause PGR is approved with modifications, as discussed in this Order, on a pilot basis.

21. KU shall use its current lead/lag study to determine the CWC portion of rate base for Adjustment Clause PGR.

22. Within 20 days, KU shall file revised forms it proposes to use for the review and filing of its Adjustment Clause PGR reflective of this Order in post case correspondence referencing this case number.

23. In its initial monthly filing, within 7 days of the expected filing date, KU shall send notice to the parties in this proceeding that it will begin collecting under Adjustment Clause PGR.

24. At least 30 days prior to collection under Adjustment Clause PGR for the 12th month, KU shall file a Notice of Intent to file an application with the Commission for review of collection of expenses under the Adjustment Clause PGR and mail that notice to the parties in this current matter.

25. The Stipulation provision regarding Adjustment Clause SM is denied.

26. Seasonal residential rates shall be studied and any analysis shall be presented in LG&E’s next base rate case.

27. KU should continue to evaluate the reasonableness of utilizing a 12-CP methodology through the use of the FERC 12-CP tests in its next base rate case filing.

28. The proposed cost-of-service study utilizing the 6-CP methodology is denied.

29. KU shall conduct separate COSSs that use 12-CP, 6-CP, and 4-CP in its next base rate case filing.

30. KU shall evaluate the cost of service for the Group 1 and 2 methodology as it relates to rider mechanisms and provide such an analysis in its next base rate filing.

31. KU shall prepare an analysis that identifies the FERC Account 512 through 514 related and unrelated to utilization in its next base rate filing.

32. The cost allocation manual tendered by KU is accepted. In its next general rate case adjustment application, KU shall file a report detailing how the utilities have taken steps to ensure that costs are allocated appropriately including any new policies or procedures instituted to ensure independent review of the allocation of costs.

33. The rates and charges proposed by KU in Tariff SQF and LQF are denied.

34. The rates and charges for LG&E/KU's Tariff SQF and LQF, as set forth in Appendix D to this Order, are fair, just and reasonable rates, and these rates are approved for service rendered on and after the date of entry of this Order.

35. In its next QF proceeding, KU shall file testimony or other evidence detailing the circumstances under which a solar or wind QF customer-generator with a co-located or coupled battery energy storage system would be compensated based on the "Other" QF technology type.

36. KU's proposed changes to the SQF and LQF tariffs availability section is denied.

37. The Stipulation provision regarding NM-2 rates is approved.

38. KU shall file update avoided cost components for NMS-2 in its next QF filing.

39. KU shall follow the Commission's previously approved methodologies as discussed in the Order when setting avoided costs rates.

40. In any proposals to close KU's NMS-2 to new customers, KU shall file notice and include a description and the calculation of the 1 percent.

41. The Rate PSA rates are accepted as modified to reflect the approved return on equity and cost of long term debt. In future PSA rate calculations, KU shall utilize public information from annual reports and FERC filings.

42. Within ten days of the date of service of this Order, KU shall file the Rate PSA charges as recalculated pursuant to this Order in post-case correspondence referencing this case number for review by the Commission. KU shall include all workpapers in Excel format with cells unlocked and formulas intact.

43. Except for the tariffs that have been modified or denied, KU's proposed stipulated tariffs are approved as filed.

44. KU's proposal to limit the availability of the GTOD rate schedules is approved.

45. KU's proposal to remove legacy status from Rate GS and Rate PS legacy customers that meet the availability requirements of the current tariff that they are on is approved with the addition of the following language to the tariff: "Customers who are receiving service under this tariff who meet the availability terms as of [date of the Order] will no longer be eligible for the legacy status as outlined above."

46. KU's proposal to combine Rate EVC-L2 and Rate EVC-FAST is approved.

47. KU’s proposal to allow Rate PS customers to participate in Green Tariff Option #3 is approved.

48. KU’s proposed revisions to Rider SSP are approved.

49. KU’s proposed revisions to Rider RAR as modified by KU to reinsert the concept of jurisdictionalizing the revenue requirement are approved.

50. KU’s proposal to require customers who refuse to make adequate provision for an AMI meter to pay the AMI Opt-Out Charges is approved.

51. KU’s proposed revisions to the Customer Responsibilities section of its tariff are approved.

52. KU’s proposed revisions to the Company Responsibilities section of its tariff are approved.

53. KU’s proposal to make paperless billing the default billing method for current customers who have an email address on file is denied.

54. KU’s proposal to make paperless billing the default billing method for new customers is approved with the understanding that such customers can opt-out of paperless billing when signing up for service.

55. KU’s proposed revisions to the Deposit section of its tariff are approved.

56. KU’s proposed Pre-Pay Program is approved with the following modification to number five of the terms and conditions: “The account will be disconnected regardless of weather/temperature as the customer is responsible for ensuring that the prepay account is adequately funded. If the member cannot ensure proper funding, KU recommends the member not utilize the prepay service.”

57. KU shall notify the Commission through a post-case filing, and tariff filing if applicable, once it has developed the Pre-Pay Service Agreement, the pre-determined triggers that will notify customers of a low balance, how a customer's daily balance will be provided to the customer, and the monthly bill summary.

58. KU's request for a deviation from 807 KAR 5:006, Section 15(1)(f)1. as it pertains to the Pre-Pay Program is approved.

59. KU's proposed revisions to the Discontinuance of Service section of its tariff are approved.

60. KU's proposed Rules for Retail Electric Service Studies and Related Implementation Costs are approved.

61. KU's proposed revisions to its Net Metering Interconnection Guidelines are approved pending the final outcome of Case No. 2020-00302 with the exception of the items included in the ordering paragraphs below.

62. Any modification or installation that materially increases the capacity of an eligible generating facility shall be evaluated on the same basis of any other new application. If a customer's modification of their eligible generating facility results in a material increase in capacity, then that customer will no longer be eligible to take service under the NMS-1 tariff. Replacement of eligible generating facilities in the ordinary course of business that result in only an incidental increase in capacity shall not trigger a change in NMS-1 legacy status.

63. KU's proposal to add application fees to Level 1 Interconnection requests is denied but will be addressed in Case No. 2020-00302.

64. KU's proposal to remove the net metering service application forms from the tariff is denied.

65. The EHLF tariff is approved as proposed in the Stipulation. KU shall include KU's energy commitments in the EHLF tariff and clarify the language regarding aggregation.

66. KU shall file all Rate EHLF electric service agreements with the Commission.

67. The Stipulation provision withdrawing KU's proposed revisions to its liability provisions is approved.

68. KU's request for relief from Annual RTO membership study filing requirement is granted.

69. KU has complied with the directives related to the merger assessment from the final Order in Case No. 2020-0349.

70. KU's request for relief from Commitment No. 55 of Appendix C to the September 30, 2020 Order in Case No. 2010-00204 is granted.

71. KU's request for deviation from 807 KAR 5:041, Section 7 Voltmeter Requirements is granted, subject to any findings in 2025-00131.

72. Within 60 days of the date of service of this Order, KU shall refund to its customers all amounts collected for service rendered after January 1, 2026, through the date of entry of this Order that are in excess of the rates set forth in Appendix E attached to this Order.

73. Within 75 days of the date of service of this Order, KU shall submit a written report to the Commission in which it describes its efforts to refund all monies collected in excess of the rates that are set forth in Appendix D to this Order.

74. Within 20 days of the date of service of this Order, KU shall file with the Commission, using the Commission's electronic Tariff Filing System, new tariff sheets setting forth the rates, charges, and modifications approved or as required herein and reflecting their effective date and that they were authorized by this Order.

75. Any filings required to be filed into this record pursuant to this Order should be filed as post-case correspondence unless otherwise noted.

76. This case is closed and removed from the Commission's docket.

PUBLIC SERVICE COMMISSION

Chairman

Commissioner

Commissioner

ATTEST:

Executive Director

ENTERED
FEB 16 2026 AB
KENTUCKY PUBLIC
SERVICE COMMISSION

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2025-00113 DATED FEB 16 2026

THIRTY-FOUR PAGES TO FOLLOW

STIPULATION AND RECOMMENDATION

This Stipulation and Recommendation ("Stipulation") is entered into effective the 20th day of October 2025 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"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Lexington-Fayette Urban County Government ("LFUCG"); Louisville/Jefferson County Metro Government ("Louisville Metro"); Walmart Inc. ("Walmart"); United States Department of Defense and All Other Federal Executive Agencies ("DoD/FEA"); Sierra Club ("Sierra Club"); and The Kroger Co. ("Kroger") (collectively, the "Parties").

W I T N E S S E T H:

WHEREAS, on May 30, 2025, KU filed with the Kentucky Public Service Commission ("Commission") its Application *In the Matter of: Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and Approval of Certain Regulatory and Accounting Treatments* ("KU Application"), and the Commission has established Case No. 2025-00113 to review KU's Application;

WHEREAS, on May 30, 2025, LG&E filed with the Kentucky Public Service Commission ("Commission") its Application *In the Matter of: Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, and Approval of Certain Regulatory and Accounting Treatments* ("LG&E Application"), and the Commission has established Case No. 2025-00114 to review LG&E's Application.

WHEREAS, the AG; KIUC; LFUCG; Louisville Metro; Walmart; DoD/FEA; Kentucky Solar Industries Association, Inc., ("KYSEIA"), Sierra Club; Kroger; Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain

Association (collectively, the "Joint Intervenors"); and Kentucky Broadband and Cable Association ("KBCA") have participated as full intervenors in Case Nos. 2025-00113 and 2025-00114;

WHEREAS, an in-person informal conference for the purpose of discussing settlement and the text of this Stipulation, attended by representatives of the Parties, Joint Intervenors, KBCA, and KYSEIA took place on October 8 and 9, 2025, during which a number of procedural and substantive issues were discussed, including potential settlement of all issues pending before the Commission in these cases;

WHEREAS, the Parties hereto desire to settle all the issues pending before the Commission in these cases;

WHEREAS, Joint Intervenors, KBCA, and KYSEIA elected not to join this Stipulation and Recommendation;

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 relief, matters, or issues addressed herein;

WHEREAS, all of the Parties, who represent diverse interests and divergent viewpoints, agree that 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 this proceeding supports 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. Stay-Out Commitment. The Utilities commit to a base-rate "stay out" until August 1, 2028, such that any changes from base rates approved in Case Nos. 2025-00113 and 2025-00114 shall not take effect before that date. Therefore, the Utilities may file base rate applications no sooner than January 1, 2028, but the proposed base rates shall not take effect before August 1, 2028.

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.

(i) For avoidance of doubt, the Parties agree the Utilities may defer the items described in Article IV.

(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: $57,800,000; and

KU Operations: $132,000,000.

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 January 1, 2026.

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 ($226.1 million for KU; $104.9 million for LG&E electric) as subsequently adjusted by the Utilities' update filings (reducing the KU requested revenue increase by $6.2 million and increasing the LG&E electric requested revenue increase by $1.9 million). The Parties ask and recommend the Commission accept these adjustments as reasonable without modification including the adjustments described below for depreciation errors.[1]

(A) **Return on Equity.** The Parties stipulate a return on equity of 9.90% 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. Use of a 9.90% return on equity reduces the Utilities' proposed electric revenue requirement increases by $45.9 million for KU and $27.8 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 all mechanisms (except demand-side management cost recovery), including their environmental cost recovery mechanism, is 9.90%.

(B) **Update Long-Term Debt Rate to Reflect Lower Rates for New Long-Term Debt in Forecasted Test Year.** The Parties agree that the rate for new long-term debt included in the Utilities' forecasted test year for the August 2025 issuance should be reduced. This adjustment reduces the Utilities' proposed electric revenue requirement increases by $4.4 million for KU and $3.4 million for LG&E.

(C) **Terminal Net Salvage.** The Parties agree to reduce the Utilities' revenue requirements to remove from depreciation expense terminal net salvage for thermal units including Mill Creek 2 and Brown 3. This adjustment, which includes the associated impact on the Utilities' capitalization, reduces the Utilities' proposed electric revenue requirement increases by $16.0 million for KU and $6.8 million for LG&E.

[1] The Utilities are addressing these depreciation errors in their testimony in support of this Stipulation.

(D) **Vegetation Management Expense.** The Parties agree to adjust vegetation management expense included in the forecasted test year. This adjustment reduces the Utilities' proposed electric revenue requirement increases by $8.8 million for KU and $4.8 million for LG&E.

(E) **De-Pancaking Expense.** The Parties agree to adjust de-pancaking expense included in the forecasted test year. This adjustment reduces the Utilities' proposed electric revenue requirement increases by $6.3 million for KU and $3.5 million for LG&E.

(F) **EEI and Related Dues.** The Parties agree to remove the dues the Utilities paid to Edison Electric Institute ("EEI"), Utility Solid Waste Activities Group, Utilities Technology Council, and Waterways Council. This adjustment reduces the Utilities' proposed electric revenue requirement increases by $0.5 million for KU and $0.4 million for LG&E.

(G) **401(k) Matching Expense.** The Parties agree to remove from the forecasted test year the 401(k) matching expense for employees that participate in the defined benefit plan. This adjustment reduces the Utilities' proposed electric revenue requirement increases by $0.9 million for KU and $0.7 million for LG&E.

(H) **Updated Pension and Other Post-Employment Benefits ("OPEB") Expense.** The Parties agree to adjust the pension and OPEB expense included in the forecasted test year. The adjustment to update the pension and OPEB expense amounts will reduce the Utilities' proposed electric revenue requirement increases by $1.3 million for KU and $1.4 million for LG&E.

(I) **Depreciation Error.** The Utilities discovered depreciation calculation errors in the revenue requirements for KU and LG&E. Correcting these errors will reduce the

Utilities' proposed electric revenue requirement increases by $3.8 million for KU and $0.2 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[2]	219.9	106.8
9.90% return on equity	(45.9)	(27.8)
Updated long-term debt rate	(4.4)	(3.4)
Updated depreciation expense to remove terminal net salvage	(16.0)	(6.8)
Updated vegetation management expense	(8.8)	(4.8)
Updated de-pancaking expense	(6.3)	(3.5)
Removed EEI and related dues	(0.5)	(0.4)
Removed 401(k) matching for employees in defined benefit plan	(0.9)	(0.7)
Updated pension and OPEB expense	(1.3)	(1.4)
Depreciation error	(3.8)	(0.2)
Electric revenue requirement increases after stipulated adjustments	132.0	57.8

[2] *See* KU's and LG&E's Supplemental Responses to PSC 1-54 dated Aug. 25, 2025; 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 1-54 from the unadjusted total revenue requirement increases shown in KU Schedule M-2.1 and LG&E Schedule M-2.1-E. As described in Andrea Fackler's and Tim Lyons's Direct Testimonies, this increase is slightly less than the revenue deficiency shown in Schedule A because of the adjustment for imputed revenues for the Solar Share Program and the Green Tariff Business Solar option.

ARTICLE III. GAS REVENUE REQUIREMENT

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 January 1, 2026, the stipulated adjustments result in an increase in annual base rate revenues for LG&E gas operations of $44,800,000.

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 ($59.5 million) as subsequently adjusted by LG&E's update filings (increasing the requested revenue requirement by $0.8 million). The Parties ask and recommend that the Commission accept these adjustments as reasonable without modification, including the adjustment described below for a depreciation error.[3]

(A) **Return on Equity.** The Parties stipulate to a return on equity of 9.90% 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 as subsequently adjusted by LG&E's update filing. Use of a 9.90% return on equity reduces LG&E's proposed gas revenue requirement increase by $10.5 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

[3] The Utilities are addressing these depreciation errors in their testimony in support of this Stipulation.

to the Utilities' recovery under all mechanisms (except demand-side management cost recovery), including LG&E's gas line tracker (GLT) mechanism, is 9.90%.

(B) **Update Long-Term Debt Rate to Reflect Lower Rates for New Long-Term Debt in Forecasted Test Year.** The Parties agree that the rate for new long-term debt included in the Utilities' forecasted test year for the August 2025 issuance should be reduced. This adjustment reduces the proposed revenue requirement increase for LG&E's gas operations by $1.3 million.

(C) **Inline Inspection and Well Logging Expense.** The Parties agree to adjust inline inspection and well logging expenses included in the forecasted test year. This adjustment reduces the proposed revenue requirement increase for LG&E's gas operations by $4.5 million.

(D) **AGA and Related Dues.** The Parties agree to remove the dues the Utilities paid to American Gas Association ("AGA"). This adjustment reduces the proposed revenue requirement increase for LG&E's gas operations by $0.3 million.

(E) **401(k) Matching Expense.** The Parties agree to remove from base rates the 401(k) matching expense for employees that participate in the defined benefit plan. This adjustment reduces the proposed revenue requirement increase for LG&E's gas operations by $0.3 million.

(F) **Updated Pension and Other Post-Employment Benefits ("OPEB") Expense.** The Parties agree to adjust the pension and OPEB expense included in the forecasted test year. The adjustment to update the pension and OPEB expense amounts will reduce LG&E's proposed gas revenue requirement increase by $0.5 million.

(G) **Depreciation Error.** The Utilities discovered a depreciation calculation error in the revenue requirement for LG&E. Correcting this error will increase LG&E's proposed gas revenue requirement by $1.9 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[4]	60.3
9.90% return on equity	(10.5)
Updated long-term debt rate	(1.3)
Updated inline inspection and well logging expense	(4.5)
Removed AGA and related dues	(0.3)
Removed 401(k) matching for employees in defined benefit plan	(0.3)
Updated pension and OPEB expense	(0.5)
Depreciation error	1.9
Gas revenue requirement increase after stipulated adjustments	44.8

ARTICLE IV. DEFERRAL ACCOUNTING

4.1. Deferral Accounting Requests. The Parties agree the Commission should approve deferral accounting treatment for the Utilities for any actual expense amounts above or below the expense levels in base rates for the following items:

(A) Pension and OPEB Expense;

[4] *See* LG&E's Updated Response to PSC 1-54 dated Aug. 25, 2025; 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 1-54 from the unadjusted rounded total revenue requirement increase shown in LG&E Schedule M-2.1-G.

(B) Storm Restoration Expense;

(C) Vegetation Management Expense;

(D) De-Pancaking Expense; and

(E) Inline Inspection and Well Logging Expense.

4.2. Regulatory Assets and Liabilities. For the items identified in Section 4.1, the Utilities will establish a regulatory asset for amounts exceeding the base rate level and a regulatory liability for amounts below the base rate level. For avoidance of doubt, the Utilities' deferral accounting will include the deferral of any amounts removed or adjusted pursuant to Articles II and III, consistent with the treatment of expense variances above or below base rate levels.

4.3. Recovery of Deferral Accounting Requests. The Utilities will address recovery of any regulatory assets or liabilities in the Utilities' next base rate cases.

4.4. Annual Reporting. As the Utilities proposed in Mr. Robert Conroy's testimony, the Utilities will make an annual filing with the Commission within 90 days of the end of each calendar year to report on and have Commission review of the deferred storm restoration and vegetation management amounts. Additionally, the Utilities will report on pension and OPEB expense, de-pancaking, and inline inspection and well logging expense in this annual filing.

ARTICLE V. <u>REVENUE ALLOCATION AND RATE DESIGN</u>

5.1. 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 gas operations, as set forth on the schedules designated Stipulation Exhibit 1 (KU), Stipulation Exhibit 2 (LG&E electric), and Stipulation Exhibit 3 (LG&E gas) attached hereto, are fair, just, and reasonable.

5.2. Tariff Sheets. The Parties hereto recommend to the Commission that, effective January 1, 2026, the Utilities shall implement the electric and gas rates set forth on the tariff sheets in Stipulation Exhibit 4 (KU), Stipulation Exhibit 5 (LG&E electric), and Stipulation Exhibit 6 (LG&E gas) attached hereto.

5.3. Residential Rate Increase and Basic Service Charge Increase. The Parties agree the Utilities' overall residential rate increase percentage and the residential Basic Service Charge increase percentage (i.e., for Rates RS, RTOD-Energy, RTOD-Demand, and RGS) will be the system average increase percentage for the relevant Utility, as adjusted for rounding.

5.4. Subsidy Reduction. The Parties agree to the following subsidy reductions:

(A) KU Rate FLS: $382,665

(B) KU Rate RTS: $2,518,169; LG&E Rate RTS: $2,219,333

(C) KU Rate TODP: $7,910,739; LG&E Rate TODP: $4,695,334

(D) KU Rate TODS: $1,201,286; LG&E Rate TODS: $768,296

ARTICLE VI. GENERATION COST RECOVERY ADJUSTMENT CLAUSE

6.1. Adjustment Clause GCR. The Parties agree, and the Commission should authorize, that the Utilities will recover all non-fuel costs of all new generation and energy storage assets approved by the Commission but not yet in service as of the date of the final order in these proceedings, excluding Mill Creek 6, through a permanent Generation Cost Recovery Adjustment Clause ("Adjustment Clause GCR"), attached hereto as Stipulation Exhibits 7 (KU) and 8 (LG&E electric).

(A) Costs recovered through Adjustment Clause GCR will be all non-fuel costs, less investment tax credit amortization and production tax credits grossed up for income taxes, of such Commission-approved generation and energy storage assets from their in-service dates through their retirement dates, including without limitation depreciation, a weighted average cost of capital carrying cost using the most recently approved base rate return on equity appropriately grossed up for income taxes, and all non-fuel operating expenses (including without limitation property taxes). Property taxes for the first year shall be based on the CWIP balance at the first of the year, not the in-service cost. During each expense month, the weighted average cost of capital will apply to the undepreciated capital cost of the generation and energy storage assets (including any future plant additions) and regulatory asset balance for AFUDC, adjusted for accumulated deferred income taxes and unamortized investment tax credits without any reduction for asset net operating loss accumulated deferred income taxes.

(B) The first expense month for a generation or energy storage asset cost recovery through Adjustment Clause GCR will be the month in which the asset goes in service, and the last expense month will be the month in which the asset retires. Cost recovery for any expense month will be billed in the second month thereafter (the billing month), e.g., for a January expense month, the following March will be the billing month.

6.2. Monthly Reporting. The Utilities agree to work with Commission Staff on the monthly reporting forms associated with Adjustment Clause GCR, if approved, as soon as practical after the Order in this proceeding. The Utilities expect that the reporting forms would be similar to the ECR mechanism. The Utilities believe Commission-initiated annual reviews of the operation of the mechanism would be appropriate to allow the Commission to determine the prudence of the costs recovered through the mechanism.

ARTICLE VII. SHARING MECHANISM ADJUSTMENT CLAUSE

7.1. Approve Adjustment Clause SM. The Parties agree the Commission should approve a new time-limited Sharing Mechanism Adjustment Clause ("Adjustment Clause SM") to facilitate the rate case stay-out addressed in Article 1.1. The proposed tariff sheets for Adjustment Clause SM are attached as Stipulation Exhibits 9 (KU), 10 (LG&E electric), and 11 (LG&E gas).

7.2. Purpose and Function of Adjustment Clause SM. In lieu of a comprehensive base rate case analysis and its associated contested adjustments, for the last thirteen months of the rate case stay-out (i.e., July 2027 through and including July 2028), Adjustment Clause SM will account for any Kentucky-jurisdictional base rate revenue deficiency or surplus as determined by the return-on-equity range ("deadband") as defined in Section 7.3 below. It will distribute any revenue surplus to customers or collect any revenue deficiency from customers; no distribution or collection will occur if the earned return on equity is within the deadband. The Utilities' calculations for Adjustment Clause SM will exclude all non-jurisdictional revenues, expenses, and capital and all revenue, expenses, and capital recovered through other jurisdictional non-base-rate mechanisms, and it will appropriately account for any approved expense deferrals addressed in Articles I and II to ensure there is no over- or under-recovery of such expenses. Adjustment Clause SM will remain in effect thereafter solely for the purpose of collecting or distributing appropriate amounts from or to customers, including any appropriate true-up amounts.

7.3. Return on Equity Deadband. Adjustment Clause SM will use a return on equity deadband of 9.40% – 10.15% to determine whether any revenue surplus or deficiency for the subject time period exists. Any revenue surplus or deficiency above or below the deadband will be distributed to or collected from customers, respectively. No distribution or collection will occur if the earned return on equity is within the deadband.

7.4. Adjustment Clause SM Calculations. The following items address calculations under Adjustment Clause SM to determine any revenue surplus or deficiency above or below the return on equity deadband.

(A) The Utilities will use historical, not forecast, data.

(B) The Utilities will use Kentucky-jurisdictional revenues, costs, and capitalization in the calculation of Adjustment Clause SM.

(C) The Utilities will use 14-month average jurisdictional capitalization (not rate base), i.e., the Utilities will use the average of month-end jurisdictional capitalization beginning with June 2027 through and including July 2028, and will make appropriate capital adjustments described in the direct testimony of Andrea M. Fackler in Appendix G inclusive of new Adjustment Clauses GCR and SM as applicable. The Utilities will calculate adjusted jurisdictional capitalization, capital structure, and cost rates for debt consistent with the computational approach presented in Schedule J-1.1/J-1.2 for each of the Utilities.

(D) In calculating adjusted jurisdictional revenues, expenses, and net operating income:

(i) The Utilities will make all appropriate adjustments to account for revenues and expenses addressed or affected by other cost-recovery mechanisms or regulatory accounting deferrals to eliminate any double-counting of such revenues and expenses. This includes without limitation making all appropriate adjustments to account for any approved expense deferrals addressed in Articles I and II (i.e., (1) pension and OPEB expense, (2) storm restoration cost, (3) vegetation management expense, (4) de-pancaking expense, and (5) inline inspection and well logging expense) to ensure there is no over- or under-recovery of such expenses.

(ii) The Utilities will use the depreciation rates approved in these proceedings, including those specified in this Stipulation, unless later modified by the Commission, in which case the Utilities will use the then-approved depreciation rates.

(iii) The Utilities will make the following adjustments to jurisdictional revenue and expenses:

(a) To account for the potentially distorting effect of having two July months in the Reporting Period, for July 2028 the Utilities will adjust revenues and expenses to account for the prior 12-month average usage scaled to the July 2028 month-end number of customers.[5]

(b) The Utilities will exclude expenses consistent with Articles 2.2(F), 2.2(G), 3.2(D), and 3.2(E).

(c) To the extent applicable and not otherwise addressed or inconsistent with anything stated above, the Utilities will make adjustments to jurisdictional operating revenues, operating expenses, and net operating income, including appropriate adjustments described in the direct testimony of Andrea M. Fackler in Appendix G inclusive of new Adjustment Clauses GCR and SM as applicable.

(E) None of the Parties may propose adjustments to Adjustment Clause SM computations or determinations different from, or additional to, those stated in or necessarily implied by this Stipulation.

(F) The Utilities' calculation of earned rate of return on common equity will reflect the adjusted jurisdictional net operating income, the adjusted jurisdictional capitalization, adjusted weighted average capital structure, and weighted average debt cost rates, all consistent with all applicable preceding terms of this Article.

7.5. Adjustment Clause SM Timeframes, Compliance Filings, and Review.

---

[5] To scale appropriately, the Utilities will use a 13-month average number of customers for July 2027 through and including June 2028 (i.e., month-end customer numbers for June 2027 through and including June 2028).

(A) <u>The Reporting Period and Report to Be Filed by October 1, 2028</u>. The Reporting Period is the 13-month period beginning with and including July 2027 through and including July 2028. By October 1, 2028, the Utilities will file with the Commission their calculations of the following for each utility: (1) the actual adjusted jurisdictional net operating income and earned return on common equity for each utility for the Reporting Period; (2) the adjusted jurisdictional net operating income necessary to achieve the return on common equity at the top and bottom of the return in equity deadband; and (3) the amount, if any, by which the actual adjusted net operating income exceeds the adjusted net operating income for the top end of the return on equity deadband ("surplus") or falls short of the adjusted net operating income for the bottom end of the return on equity deadband ("deficiency").

(i) The Utilities will record regulatory liabilities for any surpluses, and they will record regulatory assets for any deficiencies.

(ii) The Commission has full authority to review the filing and conduct an appropriate review proceeding.

(B) <u>The Adjustment Period, True-Up Filing to Be Made by February 1, 2030, and True-Up Billing</u>.

(i) Through Adjustment Clause SM, the Utilities will collect or distribute any deficiency or surplus on a percentage of revenues basis over thirteen months beginning with bills issued during the November 2028 billing cycle and ending with and including the November 2029 billing cycle (the "Adjustment Period").

(ii) The Utilities will use regulatory deferral accounting to address any over- or under- collection or disbursement, which the Utilities will address in a true-up filing following the end of the Adjustment Period.

(iii) Following the end of the Adjustment Period, the Utilities will make a true-up filing with the Commission by February 1, 2030. The Utilities would implement necessary true-up adjustment on a percentage of revenues basis under Adjustment Clause SM with bills issued during the March 2030 billing cycle.

(iv) The Utilities will make only one true-up filing and one set of true-up adjustments, after which Adjustment Clause SM will cease to be in effect, and the Utilities will withdraw the Adjustment Clause SM tariff sheets from their tariffs.

ARTICLE VIII. RATE EHLF

8.1. Minimum Contract Capacity Threshold. The Parties agree the Utilities will propose a modification to Rate EHLF (Extremely High Load Factor) to reflect a minimum contract capacity threshold of 50 MVA.

8.2. Tariff Additions. The Parties agree the Utilities will propose to add tariff language to Rate EHLF to clarify the following:

(A) Rate EHLF applies only to new customers and

(B) If a customer attempts to circumvent the minimum capacity threshold of Rate EHLF by siting multiple smaller facilities, the customer will nonetheless be served under Rate EHLF.

8.3. Renewable Energy Goals. The Utilities commit to work with Rate EHLF customers in good faith to reach any necessary agreements to reasonably accommodate such customers' renewable energy goals. Such an agreement could also address the customer's use of distributed energy resources such as demand-side management, energy efficiency, and battery storage.

(A) In considering supply-side resources, the serving Utility will not place any limitations on the size of the resource considered or brought forward by a customer. For example, solar resources of 10-20 MW may be considered. Any such agreements will also address any system upgrades or other items necessary to accommodate requested resources, including the appropriate cost allocation and recovery of the costs for such upgrades or other items.

(B) The serving Utility would work with the requesting customer to reach an agreement to determine cost recovery from the customer for the selected resources and any appropriate credit to the customer's bill, including consideration of any related Renewable Energy Credits.

(C) Any such agreement would include appropriate, circumstance-specific terms and conditions, including collateral requirements, negotiated by the Company and the requesting customer.

(D) The serving Utility would submit all such agreements to the Commission for review and approval.

ARTICLE IX. TREATMENT OF CERTAIN SPECIFIC ISSUES

9.1. Depreciation Rates for Future Units. The Parties agree the Utilities will update the depreciation lives for Mill Creek 5, Mill Creek 6, and Brown 12 to 45 years.

9.2. Rate Base Calculations in Future Rate Cases. In their next base rate cases, the Utilities will present their rate base calculations with regulatory assets and liabilities included.

9.3. Seasonal Residential Rates. The Utilities agree to study seasonal residential rates and present the results of such study in their next base rate cases.

9.4. EV Charger Rate. The Utilities agree to work with Walmart to propose an EV fast charger rate in their next base rate cases.

9.5. Green Tariff. The Parties agree the Utilities will modify their tariffs to make Green Tariff Option #3 available to customers served under Rate PS so long as the rate design proposed by this Stipulation is approved by the Commission.

9.6. Rate PSA (Pole and Structure Attachment Charges). The Parties agree the following Rate PSA rates are appropriate for the Utilities to reflect the stipulated return on equity and updated long-term debt rate:

Two-User Wireline Attachment Rate:	$9.79
Three-User Wireline Attachment Rate:	$10.12
Linear Foot of Duct:	$1.16
Wireless Facility on top of pole:	$49.76

9.7. Rate LS (Lighting Service). The Parties agree Rate LS rates will be reduced to reflect the stipulated reduction in cost of capital, which reduction is reflected in the rates shown in Stipulation Exhibits 1, 2, 4, and 5.

9.8. Rates RTS (Retail Transmission Service) and TODP (Time-of-Day Primary Service). The Parties agree the Utilities will propose a modification to Rate RTS and TODP to a revenue-neutral rate design to lower energy charges and increase demand charges. The stipulated rate increase will be applied to demand charges.

9.9. Rate CGS (Firm Commercial Gas Service). The Parties agree LG&E will increase the basic service charge for Rate CGS by 25%.

9.10. Rates PS (Power Service) and GS (General Service) Grandfathering. As the Utilities proposed in Mr. Michael Hornung's Direct Testimony, the Parties agree the Utilities will remove grandfathered status from the grandfathered customers that meet the availability requirements of their rate schedules on the date new rates go into effect from these proceedings.

Rates PS and GS customers that do not meet the availability requirements of their rate schedules will continue to maintain grandfathered status.

9.11. Riders CSR-1 (Curtailable Service Rider-1) and CSR-2 (Curtailable Service Rider-2). The Parties agree the Utilities will increase all CSR-1 and CSR-2 rates and penalties by 40%.

9.12. Liability Provisions in Tariffs. The Parties agree the Utilities will withdraw their requested changes in these proceedings to the liability provisions in their tariffs.

9.13. Net Metering. The Utilities agree they will not close their NMS-2 rates to new participants earlier than the effective date of new rates resulting from their next base rate cases. The Utilities will leave the NMS-2 rates at their current level. These rates are the product of negotiation and are not calculated using any particular methodology.

9.14. Streetlight Issues. The Utilities commit to continue their proactive streetlight inspections and smart streetlight efforts for LFUCG and Louisville Metro. The Utilities will work cooperatively with LFUCG and Louisville Metro regarding such inspection programs and smart streetlight efforts, and they will provide reasonable additional reporting to LFUCG and Louisville Metro concerning the same. LFUCG and Louisville Metro acknowledge that smart streetlights may reduce the need for streetlight inspections over time.

ARTICLE X. MISCELLANEOUS PROVISIONS

10.1. 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 this case is true or valid.

10.2. 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 by December 31, 2025.

10.3. Following the execution of this Stipulation, the Parties shall cause the Stipulation to be filed with the Commission on October 20, 2025, together with a request to the Commission for consideration and approval of this Stipulation.

10.4. 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 this proceeding, and all Parties will clearly and definitively ask the Commission to accept and approve the Stipulation as such.

10.5. 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.

10.6. 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.

10.7. 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.

10.8. 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.

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

10.10. 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.

10.11. 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.

10.12. 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.

10.13. 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.

10.14. 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.

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

[Signature Pages Follow]

APPENDIX A: LIST OF STIPULATION EXHIBITS

Stipulation Exhibit 1:	KU Electric Revenue Allocation and Rate Design Schedules
Stipulation Exhibit 2:	LG&E Electric Revenue Allocation and Rate Design Schedules
Stipulation Exhibit 3:	LG&E Gas Revenue Allocation and Rate Design Schedules
Stipulation Exhibit 4:	KU Tariff Sheets
Stipulation Exhibit 5:	LG&E Electric Tariff Sheets
Stipulation Exhibit 6:	LG&E Gas Tariff Sheets
Stipulation Exhibit 7:	KU Adjustment Clause GCR
Stipulation Exhibit 8:	LG&E Adjustment Clause GCR
Stipulation Exhibit 9:	KU Adjustment Clause SM
Stipulation Exhibit 10:	LG&E Electric Adjustment Clause SM
Stipulation Exhibit 11:	LG&E Gas Adjustment Clause SM

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

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

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
T. Toland Lacy
John G. Horne II

Kentucky Industrial Utility Customers, Inc.

HAVE SEEN AND AGREED:

By: ______________________________

Michael L. Kurtz
Jody Kyler Cohn

Lexington-Fayette Urban County Government

HAVE SEEN AND AGREED:

By: James W. Gardner

James W. Gardner
M. Todd Osterloh
Rebecca C. Price

Subject to approval of the Urban County Council

Louisville/Jefferson County Metro Government

HAVE SEEN AND AGREED:

By: James W. Gardner

James W. Gardner
M. Todd Osterloh
Rebecca C. Price

subject to gov't approval

Walmart Inc.

HAVE SEEN AND AGREED:

By:

Carrie H. Grundmann
Steven Wing-Kern Lee

United States Department of Defense and
All Other Federal Executive Agencies

HAVE SEEN AND AGREED:

By: ______________________
Kyle J. Smith
James Brannon Dupree

Sierra Club

HAVE SEEN AND AGREED:

By: ______________________________

Joe F. Childers

The Kroger Co.

HAVE SEEN AND AGREED:

By: KBoehm 10.17.25

Kurt J. Boehm

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2025-00113 DATED FEB 16 2026

FOURTEEN PAGES TO FOLLOW

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

In the Matter of:

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

KENTUCKY UTILITIES COMPANY'S AND
LOUISVILLE GAS AND ELECTRIC COMPANY'S
NOTICE OF FILNG OF AMENDMENT
<u>TO STIPULATION AND RECOMMENDATION</u>

Kentucky Utilities Company and Louisville Gas and Electric Company hereby provide notice of the filing of the attached Amendment to Stipulation and Recommendation that they filed on October 20, 2025 in these proceedings.

Dated: November 5, 2025

Respectfully submitted,

Lindsey W. Ingram III
Stoll Keenon Ogden PLLC
300 West Vine Street, Suite 2100
Lexington, Kentucky 40507
Telephone: (859) 231-3000
Fax: (859) 253-1093
l.ingram@skofirm.com

Allyson K. Sturgeon
Vice President and Deputy
General Counsel – Regulatory
Sara V. Judd
Senior Counsel
PPL Services Corporation
2701 Eastpoint Parkway
Louisville, Kentucky 40223
Telephone: (502) 627-2088
Fax : (502) 627-3367
ASturgeon@pplweb.com
SVJudd@pplweb.com

Counsel for Kentucky Utilities Company and Louisville Gas and Electric Company

CERTIFICATE OF SERVICE

In accordance 807 KAR 5:001, Section 8 as modified by the Commission's Order of July 22, 2021 in Case No. 2020-00085 (Electronic Emergency Docket Related to the Novel Coronavirus COVID-19), this is to certify that the electronic filing has been transmitted to the Commission on November 5, 2025; and that there are currently no parties in this proceeding that the Commission has excused from participation by electronic means.

Lindsey W. Ingram III

Counsel for Kentucky Utilities Company
and Louisville Gas and Electric Company

AMENDMENT TO STIPULATION AND RECOMMENDATION

This Amendment to Stipulation and Recommendation ("Amendment") is entered into this 5th day of November, 2025 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"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Lexington-Fayette Urban County Government ("LFUCG"); Louisville/Jefferson County Metro Government ("Louisville Metro"); Walmart Inc. ("Walmart"); United States Department of Defense and All Other Federal Executive Agencies ("DoD/FEA"); Sierra Club ("Sierra Club"); and The Kroger Co. ("Kroger") (collectively, the "Parties").

W I T N E S S E T H:

WHEREAS, effective October 20, 2025, the Parties entered into the Stipulation and Recommendation filed with the Kentucky Public Service Commission ("Commission") in *In the Matter of: Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and Approval of Certain Regulatory and Accounting Treatments* ("KU Application"), Case No. 2025-00113, and *In the Matter of: Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, and Approval of Certain Regulatory and Accounting Treatments* ("LG&E Application"), Case No. 2025-00114 (collectively, the "Rate Proceedings").

WHEREAS, on November 4, 2025, it came to the attention of the Parties that the provision included in Article 11.1 below was inadvertently excluded from the Stipulation and Recommendation filed on October 20, 2025;

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

ARTICLE XI. AMENDMENTS TO STIPULATION AND RECOMMENDATION

11.1. All Other Relief Requested by Utilities to Be Approved as Filed. The Parties recommend to the Commission that, except as modified in the Stipulation and the exhibits attached thereto, all other relief requested in the Utilities' filings in the Rate Proceedings, including without limitation all rates, terms, conditions, and deferral accounting, should be approved as filed or as later corrected or amended by the Utilities in their responses to data requests.

11.2. Adjustment Clause MC2. The Utilities filed the Joint Supplemental Testimony of Robert M. Conroy and Christopher M. Garrett on October 31, 2025 in these Rate Proceedings. The Joint Supplemental Testimony included information about Adjustment Clause MC2, which the Companies originally proposed in Case No. 2025-00045. For avoidance of doubt, the Parties clarify that the Stipulation and Recommendation does not address or include Adjustment Clause MC2 and therefore the Parties are not limited in the positions they may take in these proceedings regarding Adjustment Clause MC2.

[Signature Pages Follow]

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

Kentucky Utilities Company and
Louisville Gas and Electric Company

HAVE SEEN AND AGREED:

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: ______________________________

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

Kentucky Industrial Utility Customers, Inc.

HAVE SEEN AND AGREED:

By: ______________________________

Michael L. Kurtz
Jody Kyler Cohn

Lexington-Fayette Urban County Government

HAVE SEEN AND AGREED:

By: ______________________________

James W. Gardner
M. Todd Osterloh
Rebecca C. Price

Louisville/Jefferson County Metro Government

HAVE SEEN AND AGREED:

By: ______________________________
James W. Gardner
M. Todd Osterloh
Rebecca C. Price

Walmart Inc.

HAVE SEEN AND AGREED:

By: ______________________________

Carrie H. Grundmann

Steven Wing-Kern Lee

The Kroger Co.

HAVE SEEN AND AGREED:

By: ______________________________

Kurt J. Boehm

Sierra Club

HAVE SEEN AND AGREED:

By: ______________________________

Joe F. Childers

United States Department of Defense and
All Other Federal Executive Agencies

HAVE SEEN AND AGREED:

By: SMITH.KYLE.JAMESON.1459028982 Digitally signed by SMITH.KYLE.JAMESON.1459028982 Date: 2025.11.05 10:59:23 -05'00'

Kyle J. Smith
James Brannon Dupree

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2025-00113 DATED FEB 16 2026

Overall Financial Summary

Description	Forecasted Test Period Application	Difference	Forecasted Test Year Updated	Difference	Forecasted Test Period Commission
Rate Base/Capitalization	$ 6,186,741,227	(591,068)	$ 6,186,150,159	$ (146,432,572)	$ 6,039,717,587
Requested Rate of Return	8.10%	-	8.10%	-0.70%	7.40%
Required Operating Income	$ 501,222,719	$ (344,686)	$ 500,878,033	$ (53,972,073)	$ 446,905,960
Less: Adjusted Operating Income	332,088,022	4,291,103	336,379,125	$ 14,494,180	$ 350,873,305
Income Deficiency / (Sufficiency)	169,134,697	(4,635,789)	$ 164,498,908	$ (68,466,253)	$ 96,032,655
Gross Revenue Conversion Factor	1.3381	-	1.3381	-	1.3381
Revenue Increase	$ 226,316,839	$ (6,203,086)	$ 220,113,753	$ (91,613,763)	$ 128,499,990
Percent Increase	12.11%	-0.33%	11.78%	-4.90%	6.88%

Kentucky Utilities Company Requested Rate Increase	$ 226,316,839
Kentucky Utilities Company Updated Adjustment	(6,203,086)
	$ 220,113,753
Adjustments:	
O&M Adjustments:	
Incentive Compensation	(1,911,340)
401(k) Expense	(937,029)
Membership Dues	(533,443)
Depreciation Expense	(14,454,265)
Depreciation Error	(3,974,532)
Payroll Tax	(148,924)
Rate Case Expense	(133,611)
Rate Base Adjustments	(69,537,578)
Rate Increase	$ 128,483,032
Percent Rate Increase	6.88%

*Differences are due to rounding

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2025-00113 DATED FEB 16 2026

TARIFF NMS-2
NET METERING SERVICE-2

All Excess customer generation, accumulated for the billing period, shall be credited for each month.

Residential per kWh	$0.11226

TARIFF SQF AND LGF
SMALL AND LARGE QUALIFYING FACILITY

Qualifying Facility Avoided Energy Rates for Transmission Connected Projects, without Line Losses

	QF Avoided Energy (without line losses for transmission connected projects)		
	2-Year PPA	2026	2027
Solar: Single-Axis Tracking	$31.52	$36.15	$37.35
Solar: Fixed Tilt	$31.55	$36.23	$37.45
Wind	$30.62	$34.38	$35.48
Other	$30.54	$34.80	$35.95

Qualifying Facility Avoided Capacity Rates for Transmission Connected Projects, without Line Losses

	QF Avoided Capacity (without line losses for transmission connected projects)		
	2-Year PPA	2026	2027
Solar: Single-Axis Tracking	$34.27	$35.40	$35.90
Solar: Fixed Tilt	$32.81	$33.89	$34.37
Wind	$17.24	$17.81	$18.07
Other	$19.55	$20.19	$20.48

Qualifying Facility Avoided Costs Rates for Transmission Connected Projects, without Line Losses

	QF All-in Avoided Cost Rates (without line losses for transmission connected projects)	
	2-Year PPA	2026/2027—Avoided Cost Rate

Solar: Single-Axis Tracking	$65.79	$72.40
Solar: Fixed Tilt	$64.36	$70.97
Wind	$47.86	$52.87
Other	$50.08	$55.71

Qualifying Facility Avoided Energy Rates, with Line Losses

	QF Avoided Energy (with line losses)		
	2-Year PPA	2026	2027
Solar: Single-Axis Tracking	33.02	37.86	39.13
Solar: Fixed Tilt	33.05	37.95	39.23
Wind	32.07	36.01	37.17
Other	31.99	36.45	37.66

Qualifying Facility Avoided Capacity Rates, with Line Losses

	QF All-In Avoided Capacity (with line losses)		
	2-Year PPA	2026	2027
Solar: Single-Axis Tracking	$36.48	$37.68	$38.22
Solar: Fixed Tilt	$34.92	$36.07	$36.59
Wind	$18.36	$18.96	$19.23
Other	$20.81	$21.49	$21.80

Qualifying Facility All-In Avoided Cost Rates for 2-Year and 7-Year Contracts, with Line Losses

	QF All-in Avoided Cost Rates	
	2-Year/7-Year PPA	2026/2027—Avoided Cost Rate
Solar: Single-Axis Tracking	$69.50	$76.45
Solar: Fixed Tilt	$67.98	$74.92
Wind	$50.43	$55.69
Other	$52.79	$58.70

Rates for energy purchases from seller on an as-available basis are based upon the applicable 2-year PPA.

APPENDIX E

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2025-00113 DATED FEB 16 2026

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.

RESIDENTIAL SERVICE RATE RS

Basic Service Charge per Day		$0.57
Energy Charge per kWh		
	Infrastructure	$0.07373
	Variable	$0.03853
	Total	$0.11226

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

Basic Service Charge per Day		$0.57
Energy Charge per kWh		
	Off-Peak	
	Infrastructure	$0.03788
	Off-Peak Variable	$0.03853
	Off-Peak Total	$0.07641
	On-Peak	
	Infrastructure	$0.20017
	On-Peak Variable	$0.03853
	On-Peak Total	$0.23870

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

Basic Service Charge per Day		$0.57
Energy Charge per kWh		
	Infrastructure	$0.01702
	Variable	$0.03853
	Total	$0.05555
Demand Charge per kW		
	Base Hours	$4.17
	Peak Hours	$10.78

VOLUNTEER FIRE DEPARTMENT SERVICE RATE VFD

Basic Service Charge per Day		$0.57
Energy Charge per kWh		
	Infrastructure	$0.07373
	Variable	$0.03853
	Total	$0.11226

GENERAL SERVICE RATE GS

Single-Phase		
Basic Service Charge per Day		$1.53
Energy Charge per kWh		
	Infrastructure	$0.09789
	Variable	$0.03873
	Total	$0.13662
Three-Phase		
Basic Service Charge per Day		$2.44
Energy Charge per kWh		
	Infrastructure	$0.09789
	Variable	$0.03873
	Total	$0.13662

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

Single-Phase		
Basic Service Charge per Day		$1.53
Energy Charge per kWh		
	Off-Peak	
	Infrastructure	$0.05661
	Off-Peak Variable	$0.03873
	Off-Peak Total	$0.09534
	On-Peak	
	Infrastructure	$0.28884
	On-Peak Variable	$0.03873
	On-Peak Total	$0.32757
Three-Phase		
Basic Service Charge per Day		$2.44
Energy Charge per kWh		
	Off-Peak	
	Infrastructure	$0.05661
	Off- Peak Variable	$0.03873
	Off-Peak Total	$0.09534
	On-Peak	
	Infrastructure	$0.28884
	On-Peak Variable	$0.03873

	On-Peak Total	$0.32757

<u>GENERAL TIME-OF-DAY DEMAND SERVICE RATE GTOD-DEMAND</u>

Single-Phase		
Basic Service Charge per Day		$1.53
Energy Charge per kWh		
	Infrastructure	$0.04414
	Variable	$0.03873
	Total	$0.08287
Demand Charge per kW		
	Base Hours	$15.08
	Peak Hours	$5.82
Three-Phase		
Basic Service Charge per Day		$2.44
Energy Charge per kWh		
	Infrastructure	$0.04414
	Variable	$0.03873
	Total	$0.08287
Demand Charge per kW		
	Base Hours	$15.08
	Peak Hours	$5.82

<u>ALL ELECTRIC SCHOOL RATE AES</u>

Single-Phase		
Basic Service Charge per Day		$3.13
Energy Charge per kWh		
	Infrastructure	$0.07497
	Variable	$0.03860
	Total	$0.11357
Three-Phase		
Basic Service Charge per Day		$5.14
Energy Charge per kWh		
	Infrastructure	$0.07497
	Variable	$0.03860
	Total	$0.11357

<u>POWER SERVICE RATE PS</u>

Secondary		
Basic Service Charge per Day		$3.37
Energy Charge per kWh		$0.03876
Demand Charge per kW		
	Base	$4.12
	Intermediate	$9.58
	Peak	$11.90

Primary

Basic Service Charge per Day		$7.89
Energy Charge per kWh		$0.03781
Demand Charge per kW		
	Base	$3.23
	Intermediate	$9.67
	Peak	$11.97

TIME-OF-DAY SECONDARY SERVICE RATE TODS

Basic Service Charge per Day		$7.32
Energy Charge per kWh		$0.03851
Maximum Load Charge per kVA		
	Peak Demand Period	$9.07
	Intermediate Demand	$7.39
	Base Demand Period	$3.40

TIME-OF-DAY PRIMARY SERVICE RATE TODP

Basic Service Charge per Day		$13.35
Energy Charge per kWh		$0.03221
Maximum Load Charge per kVA		
	Peak Demand Period	$10.26
	Intermediate Demand	$8.31
	Base Demand Period	$2.98

RETAIL TRANSMISSION SERVICE RATE RTS

Basic Service Charge per Day		$74.00
Energy Charge per kWh		$0.03154
Maximum Load Charge per kVA		
	Peak Demand Period	$10.01
	Intermediate Demand	$8.12
	Base Demand Period	$2.32

EXTREMELY HIGH LOAD FACTOR SERVICE RATE EHLF

Basic Service Charge per Day		$74.00
Energy Charge per kWh		$0.03154
Maximum Load Charge per kVA		$20.45

FLUCTUATING LOAD SERVICE RATE FLS

Primary Service		
Basic Service Charge per Day		$16.15
Energy Charge per kWh		$0.03754
Maximum Load Charge per kVA		
	Peak Demand Period	$8.78
	Intermediate Demand	$6.99
	Base Demand Period	$3.07
Transmission Service		
Basic Service Charge per Day		$74.15
Energy Charge per kWh		$0.03673
Maximum Load Charge per kVA		
	Peak Demand Period	$4.14
	Intermediate Demand	$3.07
	Base Demand Period	$1.56

LIGHTING SERVICE RATE LS

Overhead Service	
Lighting Emitting Diode (LED)	
390 Cobra Head, 6K-8.2K Lumen	$12.06
391 Cobra Head, 13K-16.5 Lumen	$14.27
392 Cobra Head, 22K-29K Lumen	$17.83
393 Open Bottom, 4.5K-6K Lumen	$10.75
KC1 Cobra Head, 2.5K-4K Lumen	$10.49
KC3 Cobra Head, 4K-6K Lumen	$10.87
KF1 Directional, 4.5K-6K Lumen	$13.52
KF2 Directional, 14K-17.5K Lumen	$15.66
KF3 Directional, 22K-28K Lumen	$18.42
KF4 Directional, 35K-50K Lumen	$25.68

Wood Pole		
PK5 Wood Pole		$8.76
Underground Service		$4.53
Light Emitting Diode (LED)		$4.91
KC2 Cobra Head, 2.5K-4K Lumen		$6.10
KC4 Cobra Head, 4K-6K Lumen		$8.31
396 Cobra Head, 6K-8.2K Lumen		$11.87
397 Cobra Head, 13K-16.5K Lumen		$7.98
398 Cobra Head, 22K-29K Lumen		$9.40
399 Colonial, 4-Sided, 4K-7K Lumen		$7.76
KA1 Acorn, 4K-7K Lumen		$9.26
KN1 Contemporary, 4K-7K Lumen		$11.27
KN2 Contemporary, 8K-11K Lumen		$16.54
KN3 Contemporary, 13.5K-16.5K L		$22.16
KN4 Contemporary, 21K-28K Lumen		$9.10
KN5 Contemporary, 45K-50K Lumen		$11.23
KF5 Directional, 4.5K-6K Lumen		$13.99
KF6 Directional, 14K-17.5K Lumen		$21.24
KF7 Directional, 22K-28K Lumen		$21.23
KF8 Directional, 35K-50K Lumen		$4.53
KV1 Victorian, 4K-7K Lumen		$4.91
Pole Charges		
PK1 Cobra		$18.35
PK2 Contemporary		$16.76
PK3 Post-Top Decorative Smooth		$11.45
PK4 Post-Top Historic Fluted		$16.19
Conversion Fee		
	One-Time	$197.14
	Monthly	$3.27

RESTRICTED LIGHTING SERVICE RATE RLS

Overhead Service	$10.68
High Pressure Sodium	$14.42
461 Cobra Head, 4000 Lumen	$12.06
471 Cobra Head, 4000 Lumen	$16.20
462 Cobra Head, 5800 Lumen	$12.34
472 Cobra Head, 5800 Lumen	$16.72
463 Cobra Head, 9500 Lumen	$19.29
473 Cobra Head, 9500 Lumen	$23.99
464 Cobra Head, 22000 Lumen	$30.35
474 Cobra Head, 22000 Lumen	$33.49
465 Cobra Head, 50000 Lumen	$17.34
475 Cobra Head, 50000 Lumen	$10.68
409 Cobra Head, 50000 Lumen	$14.42
426 Open Bottom, 5800 Lumen	$10.57
428 Open Bottom, 9500 Lumen	$10.69
487 Directional, 9500 Lumen	$12.17
488 Directional, 22000 Lumen	$18.57
489 Directional, 50000 Lumen	$26.23
Metal Halide	
450 Directional, 12000 Lumen	$19.47
454 Directional, 12000 Lumen	$24.84
455 Directional, 32000 Lumen	$32.66
452 Directional, 107800 Lumen	$56.81
459 Directional, 107800 Lumen	$62.18
451 Directional, 32000 Lumen	$27.29
Mercury Vapor	
446 Cobra Head, 7000L	
456 Cobra Head, 7000L	$15.77
447 Cobra Head, 10000 Lumen	$15.77
457 Cobra Head, 10000 Lumen	$17.85
448 Cobra Head, 20000 Lumen	$17.39

458 Cobra Head, 20000 Lumen	$20.18
404 Open Bottom 7000 Lumen	$14.11
Incandescent	
421 Tear Drop, 1000 Lumen	$4.58
422 Tear Drop, 2500 Lumen	$6.05
424 Tear Drop, 4000 Lumen	$9.27
425 Tear Drop, 6000 Lumen	$12.08
Underground Service	
Metal Halide	
460 Directional, 12000 Lumen	$36.51
469 Directional, 32000 Lumen	$43.30
470 Directional, 107800 Lumen	$72.55
490 Contemporary, 12000 Lumen	$20.97
491 Contemporary, 32000 Lumen	$29.40
493 Contemporary, 107800 Lumen	$60.91
494 Contemporary, 12000 Lumen	$36.72
495 Contemporary, 32000 Lumen	$45.40
496 Contemporary, 107800 Lumen	$76.65
High Pressure Sodium	
440 Acorn, 4000 Lumen	$18.93
410 Acorn, 4000 Lumen	$26.79
401 Acorn, 5800 Lumen	$20.32
411 Acorn, 5800 Lumen	$28.59
420 Acorn, 9500 Lumen	$20.58
430 Acorn, 9500 Lumen	$29.00
466 Colonial, 4-Sided, 4000 Lumen	$13.31
412 Coach, 5800 Lumen	$39.36
413 Coach, 9500 Lumen	$39.47
467 Colonial, 4-Sided, 5800 Lumen	$15.15
468 Colonial, 4-Sided, 9500 Lumen	$15.26
492 Contemporary, 5800 Lumen	$20.24

476 Contemporary, 5800 Lumen	$22.77
497 Contemporary, 9500 Lumen	$19.85
477 Contemporary, 9500 Lumen	$27.69
498 Contemporary, 22000 Lumen	$23.55
478 Contemporary, 22000 Lumen	$35.95
499 Contemporary, 50000 Lumen	$28.71
479 Contemporary 50000 Lumen	$44.46
414 Victorian, 5800 Lumen	$39.38
415 Victorian, 9500 Lumen	$39.46

<u>LIGHTING ENERGY SERVICE RATE LE</u>

Energy Charge per kWh	$0.08554

<u>TRAFFIC ENERGY SERVICE RATE TE</u>

Basic Service Charge per Day	$0.14
Energy Charge per kWh	$0.10345

<u>POLE AND STRUCTURE ATTACHMENT RATE PSA</u>

Charges, Terms and Conditions	
Two-User Wireline Pole Attachment	$10.45
Three-User Wireline Pole Attachment	$10.71
Linear Foot Duct	$0.94
Wireless Facility Company Pole	$52.89

<u>ELECTRIC VEHICLE SUPPLY EQUIPMENT RATE EVSE</u>

Monthly Charging Unit Fee		
	Networked Charger A	
	Single	$187.41
	Dual	$323.59
	Networked Charger B	
	Single	$157.36
	Dual	$249.24
	Non-Networked Charger	
	Single	$83.33

<u>ELECTRIC VEHICLE CHARGE SERVICE RATE EVC</u>

EVC-L2 Fee for Use		$0.24
EVC-FAST Fee for Used		$0.25

<u>OUTDOOR SPORTS LIGHTING SERVICE RATE OSL</u>

Secondary		
Basic Service Charge per Day		$3.37
Energy Charge per kWh		$0.03876
Maximum Load Charge per kVA		
	Peak Demand Period	$20.85
	Base Demand Period	$2.83
Primary		
Basic Service Charge per Day		$7.89
Energy Charge per kWh		$0.03781
Maximum Load Charge per kVA		
	Peak Demand Period	$16.60
	Base Demand Period	$2.42

<u>SPECIAL CHARGES</u>

Returned Payment		$2.72
Meter Test		$84.00
Disconnecting Service		$82.00
Reconnecting Service		$82.00
Meter Pulse		$22.00
Unauthorized Connection		
	Without replacement	$54.00
	1/10 standard replacement	$74.00
	1/10 AMR replacement	$94.00
	1/10 AMI replacement	$144.00
	3/0 standard replacement	$159.00
	3/0 standard replacement	$244.00
AMI Opt-Out		
	Opt-out fee	$74.00
	Monthly fee	$24.00 per Month

<u>STANDARD RIDER FOR REDUNDANT CAPACITY CHARGE RC</u>

Capacity Reservation Charge		
	Secondary Distribution	$2.25
	Primary Distribution	$1.65

CURTAILABLE SERVICE RIDER-1 CSR-1

Transmission Voltage Service	$(4.48) per kVa of Curtailable Billing Demand
Primary Voltage Service	$(4.63) per kVa of Curtailable Billing Demand
Non-Compliance Charge	$22.40 per kVA

CURTAILABLE SERVICE RIDER-2 CSR-2

Transmission Voltage Service	$(8.26) per kVa of Curtailable Billing Demand
Primary Voltage Service	$(8.40) per kVa of Curtailable Billing Demand
Non-Compliance Charge	$22.40 per kVa

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

*Honorable W. Duncan Crosby III
Attorney at Law
Stoll Keenon Ogden, PLLC
2000 PNC Plaza
500 W Jefferson Street
Louisville, KY 40202-2828

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

*Ashley Wilmes
Kentucky Resources Council, Inc.
Post Office Box 1070
Frankfort, KY 40602

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

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

*Honorable Allyson K Sturgeon
Vice President and Deputy General Counsel-
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

*Gabriel Thatcher
Attorney Senior
Lexington-Fayette Urban County Government
Department Of Law
200 East Main Street
Lexington, KY 40507

*Honorable Kurt J Boehm
Attorney at Law
Boehm, Kurtz & Lowry
425 Walnut Street
Suite 2400
Cincinnati, OH 45202

*Byron Gary
Kentucky Resources Council, Inc.
Post Office Box 1070
Frankfort, KY 40602

*Hannah Wigger
Sheppard Mullin Richter & Hampton LLP
2099 Pennsylvania Avenue NW, Suite 1
Washington, DC 20006

*Kyle J Smith
General Attorney
U.S. Army Legal Services Agency
9275 Gunston Road
ATTN: JALS-RL/IP
Fort Belvoir, VA 22060-554

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

*James B Dupree
50 Third Ave
Building 1310- Pike Hall
Fort Knox, KY 40121

*Honorable Lindsey W Ingram, III
Attorney at Law
STOLL KEENON OGDEN PLLC
300 West Vine Street
Suite 2100
Lexington, KY 40507-1801

*Honorable David J. Barberie
Managing Attorney
Lexington-Fayette Urban County Government
Department Of Law
200 East Main Street
Lexington, KY 40507

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

*Lawrence W Cook
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KY 40601-8204

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

*Jody Kyler Cohn
Boehm, Kurtz & Lowry
425 Walnut Street
Suite 2400
Cincinnati, OH 45202

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

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

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

*Honorable Michael L Kurtz
Attorney at Law
Boehm, Kurtz & Lowry
425 Walnut Street
Suite 2400
Cincinnati, OH 45202

*Steven W Lee
Spilman Thomas & Battle, PLLC
1100 Brent Creek Blvd., Suite 101
Mechanicsburg, PA 17050

*Nathaniel Shoaff
Sierra Club
2101
Webster St. , Suite 1300
Oakland, CA 94612

*Kentucky Utilities Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40232-2010

*Paul Werner
Sheppard Mullin Richter & Hampton LLP
2099 Pennsylvania Avenue NW, Suite 1
Washington, DC 20006

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

*Rick E Lovekamp
Manager - Regulatory Affairs
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

*Toland Lacy
Office of the Attorney General
700 Capital Avenue
Frankfort, KY 40601

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

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

*Rebecca C. Price
Sturgill, Turner, Barker & Moloney
155 East Main Street
Lexington, KY 40507