Rick E. Lovekamp
Sr. Manager Regulatory Strategy/Policy
State Regulation and Rates
O 502-627-3780
rick.lovekamp@lge-ku.com

a PPL company

Jeff Cline
Procedure Development Coordinator
Division of General Administration Filings Branch
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601-8294

April 1, 2025

RE: Kentucky Public Service Commission Annual Financial and Statistical Report

Dear Mr. Cline:

On March 18, 2025, pursuant to 807 KAR 5:006, Sec. 4, Kentucky Utilities Company ("KU") electronically filed with the Commission the 2024 Annual Financial and Statistical Report. KU is submitting its FERC Form 1: Annual Report of Major Electric Utilities via e-mail to PSCED@ky.gov.

Should you require any additional information about these matters, please contact me or Don Harris at 502-627-2021.

Sincerely,

Rick E. Lovekamp

THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company) Kentucky Utilities Company	Year/Period of Report End of: 2024/ Q4

400 Kentucky Utilities Company 01/01/2024 - 12/31/2024

Services Performed by Independent CPA

	Yes/No	A/C/R
Are your financial statements examined by a Certified Public Accountant?		
Enter Y for Yes or N for No	Y	
If yes, which service is performed?		
Enter an X on each appropriate line		
Audit		X
Compilation		
Review		
Please enclose a copy of the accountant’s report with annual report.		

400 Kentucky Utilities Company 01/01/2024 - 12/31/2024

Principal Payment and Interest Information

	Amount	Yes/No
Amount of Principal Payment During Calendar Year	$0.00	
Is Principal Current?		Y
Is Interest Current?		Y

KENTUCKY UTILITIES COMPANY
ADDITIONAL INFORMATION TO BE FURNISHED WITH
2024 ANNUAL REPORT

ELECTRIC UTILITIES

Please furnish the following information, for Kentucky Operations only, and attach to your Annual Report:

Number of Rural Customers (Other than Farms)	INFORMATION NOT AVAILABLE
Number of Farms Served (A farm is any agricultural operating unit consisting of 3 acres or more)	INFORMATION NOT AVAILABLE
Number of KWH sold to all Rural Customers	INFORMATION NOT AVAILABLE
Total Revenue from all Rural Customers	INFORMATION NOT AVAILABLE

LINE DATA

Total number of Miles of Wire Energized (Located in Kentucky)	31,159
Total number of Miles of Pole line (Located in Kentucky)	19,639

Name of Counties in which you furnish Electric Service:
(If additional space is required, add additional sheet)

Adair	Campbell	Fayette	Harrison	Lincoln	Muhlenberg	Russell
Anderson	Carlisle	Fleming	Hart	Livingston	Nelson	Scott
Ballard	Carroll	Franklin	Henderson	Lyon	Nicholas	Shelby
Barren	Casey	Fulton	Henry	Madison	Ohio	Spencer
Bath	Christian	Gallatin	Hickman	Marion	Oldham	Taylor
Bell	Clark	Garrard	Hopkins	Mason	Owen	Trimble
Bourbon	Clay	Grant	Jessamine	McCracken	Pendleton	Union
Boyle	Crittenden	Grayson	Knox	McCreary	Pulaski	Washington
Bracken	Daviess	Green	Larue	McLean	Robertson	Webster
Bullitt	Edmonson	Hardin	Laurel	Mercer	Rockcastle	Whitley
Caldwell	Estill	Harlan	Lee	Montgomery	Rowan	Woodford

400 Kentucky Utilities Company 01/01/2024 - 12/31/2024

Supplemental Electric Information

	Revenues	KWHs Sold	Customers
Residential (440)	$702,923,837.00	5,933,105,333	450,673
Commercial and Industrial Sales			
Small (or Comercial)	$485,008,327.00	3,992,523,280	83,875
Large (or Industrial)	$435,621,481.00	6,125,647,206	1,624
Public St and Hwy Lighting (444)	$6,919,578.00	18,714,641	1,515
Other Sales to Public Authorities (445)	$150,349,784.00	1,525,709,524	8,912
Sales to Railroads and Railways (446)	$0.00	0	0
Interdepartmental Sales (448)	$0.00	0	0
Total Sales to Ultimate Customers	$1,780,823,007.00	17,595,699,984	546,599
Sales For Resale (447)	$51,672,637.00	1,312,396,103	15
Total Sales of Electricity	$1,832,495,644.00	18,908,096,087	546,614

KENTUCKY UTILITIES COMPANY
NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES
SUPPLEMENTAL INFORMATION TO 2024 ANNUAL REPORT

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to December 31, or any payroll period ending 60 days before or after December 31.

2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.

3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1.	Payroll Period Ended (Date)	12/31/2024
2.	Total Regular Full-Time Employees	723
3.	Total Part Time and Temporary Employees	8
4.	Total Regular Full-Time Employees	731

Additional Requested Information

Utility Name Kentucky Utilities Company

FEIN# (Federal Employer Identification Number)

6	1	-	0	2	4	7	5	7	0

Contact Person Jeanne M. Kugler

Contact Person's E-Mail Address JMKugler@pplweb.com

Utility's Web Address www.lge-ku.com

Please complete the above information, if it is available.

If there are multiple staff who may be contacts please include their names and e-mail addresses also.

FERC FORM NO. 1 REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER		
IDENTIFICATION		
01 Exact Legal Name of Respondent Kentucky Utilities Company		02 Year/ Period of Report End of: 2024/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) One Quality Street, Lexington, KY 40507		
05 Name of Contact Person Jeanne M. Kugler		06 Title of Contact Person Manager, Regulatory Reporting
07 Address of Contact Person (Street, City, State, Zip Code) 220 West Main Street, Louisville, KY 40202		
08 Telephone of Contact Person, Including Area Code (502) 627-4779	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 03/18/2025
Annual Corporate Officer Certification		
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.		
01 Name Christopher M. Garrett 02 Title VP - Finance and Accounting	03 Signature Christopher M. Garrett	04 Date Signed (Mo, Da, Yr) 03/18/2025
Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.		

Utility ID: 400

OATH

Commonwealth of Kentucky)
) ss:
County of Jefferson)

Christopher M. Garrett makes oath and says
(Name of Officer)

that he/she is VP - Finance and Accounting of
(Official title of officer)

Kentucky Utilities Company
(Exact legal title or name of respondent)

that it is his/her duty to have supervision over the books of account of the respondent and to control the manner in which such books are kept; that he/she knows that such books have, during the period covered by the foregoing report, been kept in good faith in accordance with the accounting and other orders of the Public Service Commission of Kentucky, effective during the said period; that he/she has carefully examined the said report and to have the best of his/her knowledge and belief the entries contained in the said report have, so far as they relate to matters of account, been accurately taken from the said books of account and are in exact accordance therewith; that he/she believes that all other statements of fact contained in the said report are true; and that the said report is a correct and complete statement of the business and affairs of the above-named respondent during the period of time from and including

January 1, 2024 , to and including December 31, 2024

Christopher M. Garrett
(Signature of Officer)

subscribed and sworn to before me, a Notary Public , in and for

the State and County named in the above this 18th day of March, 2025

(Apply Seal Here)

TAMMY J. ELZY
COMM EXPIRES 11/09/2026
NOTARY PUBLIC
ID # KYNP61560
STATE AT LARGE, KENTUCKY

My Commission expires November 9, 2026

Tammy J. Elzy
(Signature of officer authorized to administer oath)

[Persons making willful false statements in this report may be punished by fine or imprisonment under KRS 523.040 and 523.100.]

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

1. one million megawatt hours of total annual sales,
2. 100 megawatt hours of annual sales for resale,
3. 500 megawatt hours of annual power exchanges delivered, or
4. 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

a. Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

b. The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

c. Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

d. For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a. Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b. Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e. The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

f. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

g. Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

IV. When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

a. FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b. FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII. For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

X. Schedule specific instructions are found in the applicable taxonomy and on the blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

3. 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
4. 'Person' means an individual or a corporation;
5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;
7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......
11. "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

a. 'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Kentucky Utilities Company		02 Year/ Period of Report End of: 2024/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) One Quality Street, Lexington, KY 40507		
05 Name of Contact Person Jeanne M. Kugler		06 Title of Contact Person Manager, Regulatory Reporting
07 Address of Contact Person (Street, City, State, Zip Code) 220 West Main Street, Louisville, KY 40202		
08 Telephone of Contact Person, Including Area Code (502) 627-4779	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 03/18/2025

Annual Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Christopher M. Garrett	03 Signature Christopher M. Garrett	04 Date Signed (Mo, Da, Yr) 03/18/2025
02 Title VP - Finance and Accounting		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	None
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☑ No annual report to stockholders is prepared		
	Page 2		

FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Christopher M. Garrett

VP - Finance and Accounting

220 West Main Street, Louisville, KY 40202

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Incorporation: KY

Date of Incorporation: 1912-08-17

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Respondent furnished electric services in Kentucky and Virginia.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?
(1)
☐ Yes

(2)
☑ No

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

Kentucky Utilities Company (KU) is a wholly-owned subsidiary of LG&E and KU Energy LLC (LKE). PPL Corporation (PPL), based in Allentown, PA holds all of the membership interests in LKE.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	[a] President	John R. Crockett III			
2	[b] Vice President and Chief Operating Officer	Thomas A. Jessee		2024-03-04	
3	Vice President-Finance and Accounting	Christopher M. Garrett			

FOOTNOTE DATA

(a) Concept: OfficerTitle
Salary information for all officers is on file in the office of the respondent.
(b) Concept: OfficerTitle
Effective March 3, 2024, Lonnie E. Bellar resigned as Chief Operating Officer from Kentucky Utilities Company and Thomas A. Jessee, Vice President of Kentucky Utilities Company, was appointed Vice President and Chief Operating Officer of Kentucky Utilities Company, effective March 4, 2024.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	John R. Crockett III, President	220 West Main Street, Louisville, KY 40202		
2	Joseph P. Bergstein, Jr., PPL Corporation Executive Vice President and Chief Financial Officer	645 West Hamilton St. Allentown PA 18101		
3	Angela K. Gosman, PPL Corporation Executive Vice President and Chief Human Resources Officer	645 West Hamilton St. Allentown PA 18101		
4	Vincent Sorgi, PPL Corporation President and Chief Executive Officer	645 West Hamilton St. Allentown PA 18101		
5	Wendy E. Stark, PPL Corporation Executive Vice President Utilities, Chief Legal Officer and Corporate Secretary	645 West Hamilton St. Allentown PA 18101		
6	Francis X. Sullivan, PPL Corporation Executive Vice President and Chief Operating Officer	645 West Hamilton St. Allentown PA 18101		
7	Dean A. Del Vecchio, PPL Corporation Executive Vice President and Chief Technology & Innovation Officer	645 West Hamilton St. Allentown PA 18101		

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ Yes ☐ No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	Open Access Transmission Tariff (OATT) - Attachment O - Schedule 7, 8, and 10 vs. 15.0.0	Docket No. ER20-1466-001
2	Open Access Transmission Tariff (OATT) - Schedule 1 vs. 11.0.0	Docket No. ER16-1543-000
3	Open Access Transmission Tariff (OATT) - Schedule 4 vs. 12.0.0	Docket No. ER17-558-000
4	Open Access Transmission Tariff (OATT) - Schedule 9 vs. 12.0.0	Docket No. ER17-558-000
5	Wholesale Generation Requirements (Municipals) - 185 vs. 17.0.0 - City of Bardstown and 157 vs. 17.0.0 - City of Nicholasville	Docket No. ER23-2219-000
6	Wholesale Other - 408 vs. 4.0.0 - Appalachian Power	Docket No. ER23-2300-000
7	Wholesale Other - 408 vs. 5.0.0 - Appalachian Power	Docket No. ER24-2929-000

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	☑ Yes ☐ No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20240311-5212	03/11/2024	ER24-1445-000	Annual Informational Attachment O Filing of Louisville Gas and Electric Company, et al. Under ER24-1445	Attachment O - Schedule 7, 8, and 10
2	20240311-5212 - Schedule 1	03/11/2024	ER24-1445-000	Annual Rate Update	Schedule 1
3	Not Applicable - Schedule 4			Schedule Does Not Use Form 1 Inputs	Schedule 4
4	Not Applicable - Schedule 9			Schedule Does Not Use Form 1 Inputs	Schedule 9
5	20240501-5163	05/01/2024	ER13-2428-000	Informational Filing and Annual Update to Formula Charges [Bardstown and Nicholasville] of Kentucky Utilities Company under ER13-2428	Wholesale Generation RequirementsRate Schedule 185 and 157
6	20230629-5072			Kentucky Utilities Company submits tariff filing per 35.13(a)(2)(iii: Amended APCO Borderline Service Agreement Appendix B to be effective 8/1/2023 under ER23-2300	Wholesale Other Rate Schedule 408
7	20241024-5108			Kentucky Utilities Company submits tariff filing per : Supplemental Filing to Borderline Service Rate Schedule FERC No. 408 to be effective N/A under ER24-2929	Wholesale Other Rate Schedule 408

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
Page 106b				

Page 106b

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1.None.

2. None.

3. None.

4. None of a material nature.

5. None.

6. The Respondent was authorized by the FERC at Docket No. ES24-33-000 to issue, from time to time, from May 31, 2024 through June 17, 2026, (a) up to $650 million in the form of money pool debt, commercial paper or any other type of short-term loan and (b) up to $850 million in the form of certain long-term debt.

The Respondent participates in an intercompany money pool agreement. At December 31, 2024, the Respondent's money pool balance was $73 million.

At December 31, 2024, the Respondent had a $400 million credit facility syndicated with a group of banks that expires in December 2028. This facility was initially authorized by the KPSC at Case No. 2015-00137 and by the VSCC at Case No. PUE-2014-00031. The KPSC and VSCC authorized the most recent extension of the facility at Case No. 2023-00397 and PUR-2023-00225 respectively. At December 31, 2024, the Respondent had no cash borrowings under this facility.

At December 31, 2024, the Respondent maintained a commercial paper program for up to $400 million. Commercial paper issuances are supported by the Respondent's syndicated credit facility based on available capacity. The Respondent had $140 million of commercial paper outstanding at December 31, 2024.

On January 2, 2025, the Respondent amended its credit facility to an amount of $600 million that expires in December 2029. The amendment to this facility is authorized at Case No. 2023-00397 and PUR-2023-00225.

See Note 8 of the Notes to Financial Statements for further discussion of financing activities.

7. None.

8. During the first quarter of 2024, exempt and non-exempt employees received routine wage increases in accordance with annual salary reviews. Additionally, KU hourly employees received an annual increase effective February 19, 2024.

In July 2024, KU and the IBEW local reached, and local members subsequently ratified, a new three-year labor agreement through July 2027. The terms on the new labor agreement are not expected to have a significant impact on the financial results of KU.

9. See Notes 7 and 12 of Notes to Financial Statements on page 122.

10. None.

12. See Notes to Financial Statements on page 122.

13. Effective March 3, 2024, Lonnie E. Bellar resigned as Chief Operating Officer from Kentucky Utilities Company. Effective March 3, 2024, Thomas A. Jessee resigned as Vice President of Kentucky Utilities Company. Effective March 3, 2024, Eileen L. Saunders resigned as Vice President-Customer Services of Kentucky Utilities Company. Effective March 4, 2024, Dean A. Del Vecchio was elected director of Kentucky Utilities Company. Effective March 4, 2024, Thomas A. Jessee was elected Vice President and Chief Operating Officer of Kentucky Utilities Company. Effective March 4, 2024, Shannon L. Montgomery was elected Vice President-Customer Service of Kentucky Utilities Company. Effective March 4, 2024, Thomas Rieth was elected Vice President of Kentucky Utilities Company. Effective March 4, 2024, Steven B. Turner's title was changed to Vice President-Generation of Kentucky Utilities Company.
14. KU is a participant in a cash pooling arrangement, but its proprietary capital ratio is above 30 percent.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	11,910,760,489	11,402,888,976
3	Construction Work in Progress (107)	200	571,822,449	605,496,967
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		12,482,582,938	12,008,385,943
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	4,549,792,969	4,388,372,720
6	Net Utility Plant (Enter Total of line 4 less 5)		7,932,789,969	7,620,013,223
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		7,932,789,969	7,620,013,223
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		37,881	37,881
19	(Less) Accum. Prov. for Depr. and Amort. (122)			
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	250,000	250,000
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)			
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		61,704,356	74,784,480
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		61,992,237	75,072,361
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
35	Cash (131)		13,098,202	13,546,902
36	Special Deposits (132-134)			
37	Working Fund (135)		45,000	73,830
38	Temporary Cash Investments (136)			774,369
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		161,294,518	144,634,045
41	Other Accounts Receivable (143)		11,782,515	9,922,013
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,041,852	1,962,723
43	Notes Receivable from Associated Companies (145)		23,865	3,234
44	Accounts Receivable from Assoc. Companies (146)		13	312,853
45	Fuel Stock (151)	227	88,991,273	94,060,591
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	83,079,821	88,815,439
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	116,865	118,250
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	[(a)] 987,675	[(c)] 1,928,335
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		11,280,748	14,100,017
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)		56,483	85,111
60	Rents Receivable (172)		10,944,445	2,655,710
61	Accrued Utility Revenues (173)		102,231,031	97,646,392
62	Miscellaneous Current and Accrued Assets (174)		8,096,271	112,697
63	Derivative Instrument Assets (175)			
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		489,986,873	466,827,065
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		19,275,160	20,843,982
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	509,482,866	484,621,798

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
73	Prelim. Survey and Investigation Charges (Electric) (183)		10,336,875	10,129,464
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			61
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	51,581,929	48,336,204
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		27,173
81	Unamortized Loss on Reaquired Debt (189)		6,320,532	6,922,727
82	Accumulated Deferred Income Taxes (190)	234	[b]208,326,252	[d]210,330,393
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		805,323,614	781,211,802
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		9,290,092,693	8,943,124,451
Page 110-111				

FOOTNOTE DATA

(a) Concept: StoresExpenseUndistributed

Balance at Beginning of Year	$	1,928,335
Total Debits		6,491,430
Total Credits		(7,432,090)
Balance at End of Year	$	987,675

(b) Concept: AccumulatedDeferredIncomeTaxes

Balance at Beginning of Year	$	210,330,393
Less Debits to:		
Account 410.1		5,097,194
Account 410.2		1
Other Balance Sheet Accounts		8,699,721
Plus Credits to:		
Account 411.1		11,792,766
Account 411.2		9
Balance at End of Year	$	208,326,252

(c) Concept: StoresExpenseUndistributed

Balance at Beginning of Year	$	1,499,886
Total Debits		6,622,362
Total Credits		(6,193,913)
Balance at End of Year	$	1,928,335

(d) Concept: AccumulatedDeferredIncomeTaxes

Balance at Beginning of Year	$	221,787,021
Less Debits to:		
Account 410.1		13,855,354
Account 410.2		4
Other Balance Sheet Accounts		6,773,133
Plus Credits to:		
Account 411.1		9,171,759
Account 411.2		104
Balance at End of Year	$	210,330,393

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250	308,139,978	308,139,978
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)			
7	Other Paid-In Capital (208-211)	253	1,023,358,083	1,000,358,083
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	321,289	321,289
11	Retained Earnings (215, 215.1, 216)	118	2,360,597,762	2,236,106,651
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)		
16	Total Proprietary Capital (lines 2 through 15)		3,691,774,534	3,544,283,423
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	3,088,952,405	3,088,952,405
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256		
22	Unamortized Premium on Long-Term Debt (225)		4,334,009	4,542,877
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		8,415,579	8,937,276
24	Total Long-Term Debt (lines 18 through 23)		3,084,870,835	3,084,558,006
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		15,372,353	12,388,549
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		2,424,586	2,659,019
29	Accumulated Provision for Pensions and Benefits (228.3)		12,553,111	13,666,735
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
34	Asset Retirement Obligations (230)		64,446,725	65,679,130
35	Total Other Noncurrent Liabilities (lines 26 through 34)		94,796,775	94,393,433
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		139,768,400	92,944,758
38	Accounts Payable (232)		106,021,735	94,072,602
39	Notes Payable to Associated Companies (233)		72,545,349	25,474
40	Accounts Payable to Associated Companies (234)		99,799,464	71,802,814
41	Customer Deposits (235)		39,215,377	35,215,555
42	Taxes Accrued (236)	262	36,598,085	31,710,275
43	Interest Accrued (237)		24,319,654	23,952,932
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		5,403,567	4,987,073
48	Miscellaneous Current and Accrued Liabilities (242)		23,408,980	24,255,239
49	Obligations Under Capital Leases-Current (243)		9,309,411	8,285,727
50	Derivative Instrument Liabilities (244)			
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		556,390,022	387,252,449
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		20,183,299	1,518,331
57	Accumulated Deferred Investment Tax Credits (255)	266	81,359,791	83,041,600
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	1,411,064	734,229
60	Other Regulatory Liabilities (254)	278	627,128,574	625,007,230
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		1,000,934,556	995,133,041
64	Accum. Deferred Income Taxes-Other (283)		131,243,243	127,202,709
65	Total Deferred Credits (lines 56 through 64)		1,862,260,527	1,832,637,140
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		9,290,092,693	8,943,124,451

Page 112-113

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	1,970,270,465	1,886,937,672			1,970,270,465	1,886,937,672				
3	Operating Expenses											
4	Operation Expenses (401)	320	807,820,432	800,206,549			807,820,432	800,206,549				
5	Maintenance Expenses (402)	320	123,051,356	118,183,289			123,051,356	118,183,289				
6	Depreciation Expense (403)	336	368,952,386	356,967,258			368,952,386	356,967,258				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336										
8	Amort. & Depl. of Utility Plant (404-405)	336	15,793,128	18,231,109			15,793,128	18,231,109				
9	Amort. of Utility Plant Acq. Adj. (406)	336										
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		24,083,312	20,080,727			24,083,312	20,080,727				
13	(Less) Regulatory Credits (407.4)		429,239	283,308			429,239	283,308				
14	Taxes Other Than Income Taxes (408.1)	262	58,404,884	54,958,829			58,404,884	54,958,829				
15	Income Taxes - Federal (409.1)	262	87,597,714	73,325,316			87,597,714	73,325,316				
16	Income Taxes - Other (409.1)	262	17,706,029	13,523,619			17,706,029	13,523,619				
17	Provision for Deferred Income Taxes (410.1)	234, 272	149,657,779	140,787,819			149,657,779	140,787,819				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	163,202,116	148,407,126			163,202,116	148,407,126				
19	Investment Tax Credit Adj. - Net (411.4)	266	262,886				262,886					
20	(Less) Gains from Disp. of Utility Plant (411.6)											
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)		44	49			44	49				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)											
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,489,698,507	1,447,574,032			1,489,698,507	1,447,574,032				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		480,571,958	439,363,640			480,571,958	439,363,640				
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)			1,151								
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)			998								
33	Revenues From Nonutility Operations (417)											

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
34	(Less) Expenses of Nonutility Operations (417.1)											
35	Nonoperating Rental Income (418)											
36	Equity in Earnings of Subsidiary Companies (418.1)	119										
37	Interest and Dividend Income (419)		1,199,055	614,269								
38	Allowance for Other Funds Used During Construction (419.1)		8,084,822	2,529,139								
39	Miscellaneous Nonoperating Income (421)		55,016	1,602,077								
40	Gain on Disposition of Property (421.1)		349,502	3,008								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		9,688,395	4,748,646								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		51,253	44,556								
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		798,056	668,678								
46	Life Insurance (426.2)		(1,182,215)	(1,711,084)								
47	Penalties (426.3)		11,137	22,440								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,055,365	1,015,661								
49	Other Deductions (426.5)		577,498	548,491								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,311,094	588,742								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	396	2,100								
53	Income Taxes-Federal (409.2)	262	(1,008,280)	(114,933)								
54	Income Taxes-Other (409.2)	262	(252,702)	(28,805)								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	416,960	4								

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	16,848	104								
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)		1,944,696	1,938,848								
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(2,805,170)	(2,080,586)								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		11,182,471	6,240,490								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		131,348,334	127,548,300								
63	Amort. of Debt Disc. and Expense (428)		2,303,369	2,047,355								
64	Amortization of Loss on Reaquired Debt (428.1)		602,195	612,602								
65	(Less) Amort. of Premium on Debt-Credit (429)		208,868	208,868								
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)											
67	Interest on Debt to Assoc. Companies (430)		2,019,701	1,294,658								
68	Other Interest Expense (431)		4,112,977	3,644,188								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		4,014,390	1,422,064								
70	Net Interest Charges (Total of lines 62 thru 69)		136,163,318	133,516,171								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		355,591,111	312,087,959								
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262										

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		355,591,111	312,087,959								
Page 114-117												

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		2,236,106,651	2,114,018,692
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		355,591,111	312,087,959
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Dividends Declared-Common Stock		(231,100,000)	(190,000,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(231,100,000)	(190,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,360,597,762	2,236,106,651
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
39.1	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,360,597,762	2,236,106,651

	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1	TOTAL other Changes in unappropriated subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

STATEMENT OF CASH FLOWS

1. Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	355,591,111	312,087,959
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	368,952,386	356,967,258
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of plant and regulatory debits and credits	50,722,156	51,333,234
5.2	Amortization of Debt Discount and Debt Issuance Costs	2,696,696	2,451,089
5.3	Net (Increase) Decrease in Key Man Life Insurance	(1,182,215)	(1,689,243)
5.4	Provision for Pension and Postretirement Benefits	(5,557,234)	(4,690,977)
5.5	Amortization of Research and Development Projects	27,111	162,667
5.6	(Gain)/Loss on Sale of Assets	(298,249)	41,548
5.7	Other Deductions		
5.8	Other	1	(1)
8	Deferred Income Taxes (Net)	(13,144,225)	(7,619,407)
9	Investment Tax Credit Adjustment (Net)	(1,681,810)	(1,938,848)
10	Net (Increase) Decrease in Receivables	(32,226,796)	32,623,262
11	Net (Increase) Decrease in Inventory	13,418,853	(17,805,975)
12	Net (Increase) Decrease in Allowances Inventory	1,385	1,249
13	Net Increase (Decrease) in Payables and Accrued Expenses	596,137	(47,614,271)
14	Net (Increase) Decrease in Other Regulatory Assets	(22,522,627)	13,592,010
15	Net Increase (Decrease) in Other Regulatory Liabilities	26,340,530	(1,222,260)
16	(Less) Allowance for Other Funds Used During Construction	8,084,822	2,529,139
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Net (Increase) Decrease in Prepayments and Other Assets	2,819,269	4,059,410
18.2	Net Increase (Decrease) in Other Liabilities	(4,448,743)	(3,143,008)
18.3	Net Increase (Decrease) in Customer Advances for Construction	18,664,968	(373,127)
18.4	Pension and Postretirement Funding	(137,757)	346,398
18.5	Net Increase (Decrease) in Asset Retirement Obligations		

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
18.6	Net Increase (Decrease) in Special Funds	(93,806)	(1,327,475)
18.7	Other		(1)
18.8	Net (Increase) Decrease in Other Deferred Debits	(12,131,047)	(8,092,136)
18.9	Net Increase (Decrease) in Other Deferred Credits	96,114	86,488
18.10	Payments for Asset Retirement Obligations	(10,217,954)	(27,441,601)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	728,199,432	648,265,103
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(633,319,486)	(554,959,291)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	(8,084,822)	(2,529,139)
31	Other (provide details in footnote):		
31.1	Costs of Removal of Utility Plant	(23,367,171)	(21,654,762)
31.2	Other		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(648,601,835)	(574,084,914)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies	(20,630)	(3,208)
40	Contributions and Advances from Assoc. and Subsidiary Companies	72,519,875	(5,083)
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Proceeds for Key Man Life Insurance		6,141,568
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(576,102,590)	(567,951,637)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		459,088,000
62	Preferred Stock		

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
63	Common Stock		
64	Other (provide details in footnote):		
64.1	LG&E and KU Energy LLC Equity Contribution	126,000,000	76,000,000
64.2	Issuance of Commercial Paper		
66	Net Increase in Short-Term Debt (c)	46,823,642	
67	Other (provide details in footnote):		
67.1	Net Change in Restricted Cash	8,504,929	
70	Cash Provided by Outside Sources (Total 61 thru 69)	181,328,571	535,088,000
72	Payments for Retirement of:		
73	Long-term Debt (b)		(312,900,000)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Debt Issuance Costs	(577,312)	(4,409,068)
76.2	Net Change in Restricted Cash		(22,619,048)
76.3	Net Decrease in Short-Term Debt (c)		(7,801,953)
76.4	Return of Capital to Parent	(103,000,000)	(84,000,000)
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(231,100,000)	(190,000,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	(153,348,741)	(86,642,069)
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(1,251,899)	(6,328,603)
88	Cash and Cash Equivalents at Beginning of Period	[a]14,395,101	20,723,704
90	Cash and Cash Equivalents at End of Period	[b]13,143,202	[c]14,395,101

Page 120-121

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: CashAndCashEquivalents

Cash and Cash Equivalents is comprised of the following amounts:

Cash (131)	$	13,546,902
Working Fund (135)		73,830
Temporary Cash Investments (136)		774,369
Total Cash and Cash Equivalents	$	14,395,101

(b) Concept: CashAndCashEquivalents

Cash and Cash Equivalents is comprised of the following amounts:

Cash (131)	$	13,098,202
Working Fund (135)		45,000
Total Cash and Cash Equivalents	$	13,143,202

(c) Concept: CashAndCashEquivalents

Cash and Cash Equivalents is comprised of the following amounts:

Cash (131)	$	13,546,902
Working Fund (135)		73,830
Temporary Cash Investments (136)		774,369
Total Cash and Cash Equivalents	$	14,395,101

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

As permitted by the FERC for the 2024 FERC Form No. 1, the Notes to Financial Statements set forth below are principally from the Respondent's SEC Form 10-K and do not reflect updated information, except for Note 1, 6, 21 and 22. Note 1 was modified to update the basis of presentation for FERC reporting, Note 6 was modified to address disclosure requirements established in the FERC policy Statement, Docket No. PL19-2-000. Note 21 was included to update supplemental disclosures for Cash Flows. Note 22 was added to disclose subsequent events. Management has evaluated the impact of events occurring after December 31, 2024 up to February 13, 2025, the date that KU's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposed through March 18, 2025. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

Presentation

The accompanying financial statements are prepared on the regulatory basis of accounting in accordance with the requirements of the FERC, which is a comprehensive basis of accounting other than GAAP. The significant differences between GAAP and FERC reporting are as follows:

Reporting Classifications	FERC reporting	GAAP reporting
Balance Sheet presentation	Reported in order of Uniform System of Accounts (18 CFR Part 101) account number	Reported in order of liquidity
Amounts presented within the Balance Sheet and Income Statement	Reported without Purchase Accounting adjustments	Reported with Purchase Accounting adjustments
Pension and Post-retirement plan non-service costs or credits	Capital portion reported in Electric Plant in Service (101) and Construction Work in Progress (107) Depreciation on Capital component is reported in Accumulated Provision for Depreciation of Electric Utility Plant (108) and Depreciation Expense (403) Expense portion reported in Pension and Benefits (926) under Administrative and General	Portion capitalized for FERC is reported as a regulatory asset or liability for GAAP Regulatory Asset or Liability is amortized to Other Income and Expense Expense portion reported in Other Income and Expense
Regulatory asset maturity classification	Reported in total in Other Regulatory Assets (182.3) with no distinction between current and non-current	Short-term Regulatory Assets are reported in Current Assets and Long-Term Regulatory Assets are reported in Other Noncurrent Assets
Regulatory liability maturity classification	Reported in total in Other Regulatory Liabilities (254) with no distinction between current and non-current	Short-term Regulatory Liabilities are reported in Current Liabilities and Long-Term Regulatory Liabilities are reported in Deferred Credits and Other Noncurrent Liabilities
Accumulated cost of removal of utility plant	Reported in Accumulated Provision for Depreciation of Electric Utility Plant (108)	Reported in regulatory liabilities
Certain intangible assets	Reported in Utility Plant (101-106, 114) and Reported in Accumulated Provision for Depreciation of Electric Utility Plant (108)	Reported in Other Noncurrent Assets
Unamortized losses on reacquired debt	Reported in Unamortized Loss on Reacquired Debt (189)	Reported in Regulatory Assets
Unamortized debt expense related to long-term debt	Reported in Unamortized Debt Expenses (181)	Reported as offset to Long-term Debt
Operating lease right of use assets	Reported in PP&E (101)	Reported in Other Noncurrent Assets
Deferred tax assets and liabilities	Reported in the respective accumulated deferred income tax FERC accounts (i.e. FERC Accounts Deferred Asset (190) and Deferred Liability (282 – 283) for a gross balance sheet presentation)	Netted and categorized into noncurrent deferred tax asset and/or liability positions on the Balance Sheets
Income taxes	Income Taxes (408.1-408.2, 409.1-409.2), Deferred Taxes (410.1-410.2, 411.1-411.2) and Investment Tax Credits (411.4 -411.5) are reported on separate lines on the Income Statement	Income Taxes, Deferred Taxes and Investment Tax Credits are netted on a single line on the Income Statement.
Rent receivables	Reported in Rents Receivable (172)	Reported in Accounts Receivable - Other
Noncurrent Prepayments	Reported in Prepayments (165)	Reported in Other Noncurrent Assets
Payable and Accrued expenses	Reported in Accounts Payable (232) and Reported in Tax Collections Payable (241)	Reported in Other Current Liabilities
Certain retirement work in progress amounts	Reported in Accumulated Provision for Depreciation of Electric Utility Plant (108)	Reported in Asset Retirement Obligations
Implementation costs incurred in a cloud computing arrangement that is considered a service contract.	Reported in PP&E (101,106, 107, 111). Reported as Investing Activity on Statement of Cash Flows.	Reported in Other Noncurrent Assets. Reported as Operating Activity on Statement of Cash Flows
Borrowings from associated companies.	Reported as Investing Activity on Statement of Cash Flows (233-234)	Reported as Financing Activity on Statement of Cash Flows
Credit facility fee amortization and commitment fees	Reported in Miscellaneous General (930.2)	Reported in Interest Expense
Cloud Implementation Costs	Reported in Utility Plant (101-106, 114) on the Balance Sheet and Amort. & Depl. of Utility Plant (404-405) on the Income Statement.	Reported in Prepayments on the Balance Sheet and Other operation and maintenance on the Income Statement
Goodwill	Not included in financial records of the Utility.	Reported in Other Noncurrent Assets
Tax exempt bond funds from debt transactions held as restricted cash for future spending on a project.	Reported in Special Funds (128). Reported as Investing Activity on Statement of Cash Flows.	Reported in Other Noncurrent Assets. Reported as a changed in Cash, Cash Equivalents, Restricted Cash and Restricted Cash Equivalents in the Statement of Cash Flows.
Opportunity KY Funds held as restricted cash related to economic funding activity held in external accounts	Reported in Special Funds (128). Reported as Operating Activity on Statement of Cash Flows.	Reported in Other Noncurrent Assets. Reported as a changed in Cash, Cash Equivalents, Restricted Cash and Restricted Cash Equivalents in the Statement of Cash Flows.
Incremental equity component of the Allowance for Funds Used During Construction at Weighted Average Cost of Capital Rates	Reported in Other Regulatory Assets (182.3)	Reported in PP&E
In-Line Inspection Costs - Costs capitalized for in-line inspections per FERC special ruling.	Reported in Utility Plant (101-106) and Accumulated Provision for Depreciation of Electric Utility Plant (108) on the Balance Sheet and Depreciation Expense (403) on the Income Statement	Reported in Regulatory Assets - Noncurrent - Other on the Balance Sheet and Operations and Maintenance Expense on the Income Statement
Prepaid Pension	Reported in Special Funds (128)	Reported in Other Noncurrent Assets
Long-term debt due within one year	Reported in Bonds (221)	Reported in Current Liabilities
Commercial paper and discount	Reported in Notes Payable (231)	Reported in Short-Term Debt
Land rights, franchises and consents	Reported in Utility Plant (101)	Reported in Other Noncurrent Assets

GLOSSARY OF TERMS AND ABBREVIATIONS

PPL Corporation and its subsidiaries

CEP Reserves - CEP Reserves, Inc., a cash management subsidiary of PPL that maintains cash reserves for the balance sheet management of PPL and certain subsidiaries.

KU - Kentucky Utilities Company, a public utility subsidiary of LKE engaged in the regulated generation, transmission, distribution and sale of electricity, primarily in Kentucky.

LG&E - Louisville Gas and Electric Company, a public utility subsidiary of LKE engaged in the regulated generation, transmission, distribution and sale of electricity and the distribution and sale of natural gas in Kentucky.

LKE - LG&E and KU Energy LLC, a subsidiary of PPL and the parent of LG&E, KU and other subsidiaries.

LKS - LG&E and KU Services Company, a subsidiary of LKE that provides administrative, management and support services primarily to LG&E and KU, as well as to LKE and its other subsidiaries.

Narragansett Electric - The Narragansett Electric Company, an entity that serves electric and natural gas customers in Rhode Island. On May 25, 2022, PPL and its subsidiary, PPL Rhode Island Holdings announced the completion of the acquisition of Narragansett Electric, which will continue to provide services under the name Rhode Island Energy.

PPL - PPL Corporation, the ultimate parent holding company of PPL Electric, PPL Energy Funding, PPL Capital Funding, LKE, RIE and other subsidiaries.

PPL Capital Funding - PPL Capital Funding, Inc., a financing subsidiary of PPL that provides financing for the operations of PPL and certain subsidiaries. Debt issued by PPL Capital Funding is fully and unconditionally guaranteed as to payment by PPL.

PPL Electric - PPL Electric Utilities Corporation, a public utility subsidiary of PPL engaged in the regulated transmission and distribution of electricity in its Pennsylvania service area and that provides electricity supply to its retail customers in this area as a PLR.

PPL Energy Funding - PPL Energy Funding Corporation, a subsidiary of PPL and the parent holding company of PPL Global and other subsidiaries.

PPL Energy Holdings - PPL Energy Holdings, LLC, a subsidiary of PPL and the parent holding company of PPL Energy Funding, LKE, PPL Electric, PPL Rhode Island Holdings, PPL Services and other subsidiaries.

PPL EU Services - PPL EU Services Corporation, a subsidiary of PPL that provided administrative, management and support services primarily to PPL Electric. On December 31, 2021, PPL EU Services merged into PPL Services.

PPL Global - PPL Global, LLC, a subsidiary of PPL Energy Funding that, prior to the sale of the U.K. utility business on June 14, 2021, primarily through its subsidiaries, owned and operated WPD, PPL's regulated electricity distribution businesses in the U.K. PPL Global was not included in the sale of the U.K. utility business on June 14, 2021.

PPL Rhode Island Holdings - PPL Rhode Island Holdings, LLC, a subsidiary of PPL Energy Holdings formed for the purpose of acquiring Narragansett Electric to which certain interests of PPL Energy Holdings in the Narragansett SPA were assigned.
PPL Services - PPL Services Corporation, a subsidiary of PPL that provides administrative, management and support services to PPL and its subsidiaries.

PPL WPD Limited - PPL WPD Limited, a U.K. subsidiary of PPL Global. Prior to the sale of the U.K. utility business on June 14, 2021, PPL WPD Limited was an indirect parent to WPD. PPL WPD Limited was not included in the sale of the U.K. utility business on June 14, 2021.

RIE - Rhode Island Energy, the name under which Narragansett Electric will continue to provide services subsequent to its acquisition by PPL and its subsidiary, PPL Rhode Island Holdings on May 25, 2022.

Other terms and abbreviations

£ - British pound sterling.

401(h) account(s) - a sub-account established within a qualified pension trust to provide for the payment of retiree medical costs.

Act 11 - Act 11 of 2012 that became effective on April 16, 2012. The Pennsylvania legislation authorized the PAPUC to approve two specific ratemaking mechanisms: the use of a fully projected future test year in base rate proceedings and, subject to certain conditions, a DSIC.

Act 129 - Act 129 of 2008 that became effective in October 2008. The law amended the Pennsylvania Public Utility Code and created an energy efficiency and conservation program and smart metering technology requirements, adopted new PLR electricity supply procurement rules, provided remedies for market misconduct and changed the Alternative Energy Portfolio Standard (AEPS).

Act 129 Smart Meter program - PPL Electric's system-wide meter replacement program that installs wireless digital meters that provide secure communication between PPL Electric and the meter as well as all related infrastructure.

AFUDC - allowance for funds used during construction. The cost of equity and debt funds used to finance construction projects of regulated businesses, which is capitalized as part of construction costs.

AOCI - accumulated other comprehensive income or loss.

ARO - asset retirement obligation.

ATM Program - at-the-market stock offering program.

Bcf - billion cubic feet. A unit of measure commonly used in quoting volumes of natural gas.

Cane Run Unit 7 - a NGCC generating unit in Kentucky, jointly owned by LG&E and KU.

CCR(s) - coal combustion residual(s). CCRs include fly ash, bottom ash and sulfur dioxide scrubber wastes.

Clean Air Act - federal legislation enacted to address certain environmental issues related to air emissions, including acid rain, ozone and toxic air emissions.

Clean Water Act - federal legislation enacted to address certain environmental issues relating to water quality including effluent discharges, cooling water intake, and dredge and fill activities.

COVID-19 - the disease caused by the coronavirus identified in 2019 that caused a global pandemic.

CPCN - Certificate of Public Convenience and Necessity. Authority granted by the KPSC pursuant to Kentucky Revised Statute 278.020 to provide utility service to or for the public or the construction of certain plant, equipment, property or facilities for furnishing of utility service to the public. A CPCN is required for any capital addition, subject to KPSC jurisdiction, in excess of $100 million.

Customer Choice Act - the Pennsylvania Electricity Generation Customer Choice and Competition Act, legislation enacted to restructure the state's electric utility industry to create retail access to a competitive market for generation of electricity.

DDCP - Directors Deferred Compensation Plan.

DSIC - Distribution System Improvement Charge. Authorized under Act 11, which is an alternative ratemaking mechanism providing more-timely cost recovery of qualifying distribution system capital expenditures.

DSM - Demand Side Management. Pursuant to Kentucky Revised Statute 278.285, the KPSC may determine the reasonableness of DSM programs proposed by any utility under its jurisdiction. DSM programs consist of energy efficiency programs intended to reduce peak demand and delay the investment in additional power plant construction, provide customers with tools and information regarding their energy usage and support energy efficiency.

Earnings from Ongoing Operations - a non-GAAP financial measure of earnings adjusted for the impact of special items and used in "Item 7. Combined Management's Discussion and Analysis of Financial Condition and Results of Operations" (MD&A).

EBPB - Employee Benefit Plan Board. The administrator of PPL's U.S. qualified retirement plans, which is charged with the fiduciary responsibility to oversee and manage those plans and the investments associated with those plans.

ECR - Environmental Cost Recovery. Pursuant to Kentucky Revised Statute 278.183, Kentucky electric utilities are entitled to the current recovery of costs of complying with the Clean Air Act, as amended, and those federal, state or local environmental requirements that apply to coal combustion wastes and byproducts from the production of energy from coal.

ELG(s) - Effluent Limitation Guidelines, regulations promulgated by the EPA.

Environmental Response Fund - Established in RIPUC Docket No. 2930. Created to satisfy remedial and clean-up obligations of RIE arising from the past ownership and/or operation of manufactured gas plants and sites associated with the operation and disposal activities of such gas plants.

EPA - Environmental Protection Agency, a U.S. government agency.

EPS - earnings per share.

FERC - Federal Energy Regulatory Commission, the U.S. federal agency that regulates, among other things, interstate transmission and wholesale sales of electricity, hydroelectric power projects and related matters.

GAAP - Generally Accepted Accounting Principles in the U.S.

GHG(s) - greenhouse gas(es).

GLT - gas line tracker. The KPSC approved mechanism for LG&E's recovery of certain costs associated with gas transmission lines, gas service lines, gas risers, leak mitigation, and gas main replacements.

Green Tariff - a KPSC approved rate schedule, permitting customers to contract with LG&E or KU for the purchase of renewable energy certificates, construction of solar generation and use of the energy produced, or the purchase of energy from a renewable energy generator.

GWh - gigawatt-hour, one million kilowatt hours.

IBEW - International Brotherhood of Electrical Workers.

ICPKE - The PPL Incentive Compensation Plan for Key Employees. The ICPKE provides for incentive compensation to certain employees below the level of senior executive.

If-Converted Method - A method applied to calculate diluted EPS for a company with outstanding convertible debt. This method generally adds back the interest charges of the debt to net income and the convertible debt is assumed to have been converted to equity at the beginning of the period, and the resulting common shares are treated as outstanding shares for diluted EPS calculations.

IRA - Inflation Reduction Act, a U.S. federal law, which aims to curb inflation by possibly reducing the federal government budget deficit, lowering prescription drug prices, and investing in domestic energy production while promoting clean energy.

IRS - Internal Revenue Service, a U.S. government agency.

ISO - Independent System Operator.

KPSC - Kentucky Public Service Commission, the state agency that has jurisdiction over the regulation of rates and service of utilities in Kentucky.

KU 2010 Mortgage Indenture - KU's Indenture, dated as of October 1, 2010, to The Bank of New York Mellon, as supplemented.

kVA - kilovolt ampere.

kWh - kilowatt hour, basic unit of electrical energy.

LCIDA - Lehigh County Industrial Development Authority.

LG&E 2010 Mortgage Indenture - LG&E's Indenture, dated as of October 1, 2010, to The Bank of New York Mellon, as supplemented.

Mcf - one thousand cubic feet, a unit of measure for natural gas.

MMBtu - one million British Thermal Units.

Moody's - Moody's Investors Service, Inc., a credit rating agency.

MW - megawatt, one thousand kilowatts.

MWac - megawatt, alternating current. The measure of the power output from a solar installation.

NAAQS - National Ambient Air Quality Standards periodically adopted pursuant to the Clean Air Act.

National Grid USA - National Grid USA is a wholly-owned subsidiary of National Grid plc, a British multinational electricity and gas utility company headquartered in London, England.

NEP - New England Power Company, a National Grid U.S. affiliate.

NERC - North American Electric Reliability Corporation.

NGCC - Natural gas combined cycle.

NPNS - the normal purchases and normal sales exception as permitted by derivative accounting rules. Derivatives that qualify for this exception may receive accrual accounting treatment.

OCI - other comprehensive income or loss.

OVEC - Ohio Valley Electric Corporation, located in Piketon, Ohio, an entity in which LG&E owns a 5.63% interest and KU owns a 2.50% interest, which are recorded at cost. OVEC owns and operates two coal-fired power plants, the Kyger Creek plant in Ohio and the Clifty Creek plant in Indiana, with combined capacities of 2,120 MW.

PAPUC - Pennsylvania Public Utility Commission, the state agency that regulates certain ratemaking, services, accounting and operations of Pennsylvania utilities.

PEDFA - Pennsylvania Economic Development Financing Authority.

Performance unit - stock-based compensation award that represents a variable number of shares of PPL common stock that a recipient may receive based on PPL's attainment of (i) relative total shareowner return (TSR) over a three-year performance period as compared to companies in the PHLX Utility Sector Index; or (ii) corporate return on equity (ROE) based on the average of the annual ROE for each year of the three-year performance period. In light of the transformational nature of the potential sale of the U.K. utility business in 2021, PPL's ROE-based performance units issued for 2021 were based on a one-year performance period from January 1, 2021 to December 31, 2021; however, these units retained the three year vesting schedule and other characteristics.

PJM - PJM Interconnection, L.L.C., operator of the electricity transmission network and electricity energy market in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

PLR - Provider of Last Resort, the role of PPL Electric in providing default electricity supply within its delivery area to retail customers who have not chosen to select an alternative electricity supplier under the Customer Choice Act.

PP&E - property, plant and equipment.

PPA(s) - power purchase agreement(s).

PPL Energy Supply - prior to the June 1, 2015 spinoff, PPL Energy Supply, LLC, a subsidiary of PPL Energy Funding and the indirect parent company of PPL Montana, LLC.

PPL EU Services - PPL EU Services Corporation, a former subsidiary of PPL that, prior to being merged into PPL Services on December 31, 2021, provided administrative, management and support services primarily to PPL Electric.

PPL Montana - prior to the June 1, 2015 spinoff of PPL Energy Supply, PPL Montana, LLC, an indirect subsidiary of PPL Energy Supply that generated electricity for wholesale sales in Montana and the Pacific Northwest.

PPL WPD Investments Limited - PPL WPD Investments Limited, which was, prior to the sale of the U.K. utility business on June 14, 2021, a subsidiary of PPL WPD Limited and parent to WPD plc. PPL WPD Investments Limited was included in the sale of the U.K. utility business on June 14, 2021.

RAR – Retired Asset Recovery rider, established by KPSC orders in 2021 to provide for recovery of and return on the remaining investment in certain electric generating units upon their retirement over a ten-year period following retirement.

RCRA - Resource Conservation and Recovery Act of 1976.

Registrant(s) - refers to the Registrants named on the cover of this Report (each a "Registrant" and collectively, the "Registrants").

RIPUC - Rhode Island Public Utilities Commission, a three-member quasi-judicial tribunal with jurisdiction, powers, and duties to implement and enforce the standards of conduct under R.I. Gen. Laws § 39-1-27.6 and to hold investigations and hearings involving the rates, tariffs, tolls, and charges, and the sufficiency and reasonableness of facilities and accommodations of public utilities.

Riverstone - Riverstone Holdings LLC, a Delaware limited liability company and, as of December 6, 2016, ultimate parent company of the entities that own the competitive power generation business contributed to Talen Energy.

Rhode Island Division of Public Utilities and Carriers - the Rhode Island Division of Public Utilities and Carriers, which is headed by an Administrator who is not a Commissioner of the RIPUC, exercises the jurisdiction, supervision, power, and duties not specifically assigned to the RIPUC.

RTO - Regional Transmission Operator, an electric power transmission system operator that coordinates, controls and monitors a multi-state electric grid.

Safari Energy - Safari Energy, LLC, which was, prior to the sale of Safari Holdings on November 1, 2022, a subsidiary of Safari Holdings that provided solar energy solutions for commercial customers in the U.S.

Safari Holdings - Safari Holdings, LLC, which was, prior to its sale on November 1, 2022, a subsidiary of PPL and parent holding company of Safari Energy.

Sarbanes-Oxley - Sarbanes-Oxley Act of 2002, which sets requirements for management's assessment of internal controls for financial reporting. It also requires an independent auditor to make its own assessment.

Scrubber - an air pollution control device that can remove particulates and/or gases (primarily sulfur dioxide) from exhaust gases.

SEC - the U.S. Securities and Exchange Commission, a U.S. government agency primarily responsible to protect investors and maintain the integrity of the securities markets.

SIP - PPL Corporation's Amended and Restated 2012 Stock Incentive Plan.

Smart metering technology - technology that can measure, among other things, time of electricity consumption to permit offering rate incentives for usage during lower cost or demand intervals. The use of this technology also has the potential to strengthen network reliability.

SOFR - Secured Overnight Financing Rate, a broad measure of the cost of borrowing cash overnight collateralized by Treasury securities.

S&P - S&P Global Ratings, a credit rating agency.

Superfund - federal environmental statute that addresses remediation of contaminated sites; states also have similar statutes.

Talen Energy - Talen Energy Corporation, the Delaware corporation formed to be the publicly traded company and owner of the competitive generation assets of PPL Energy Supply and certain affiliates of Riverstone, which as of December 6, 2016, became wholly owned by Riverstone.

Talen Energy Marketing - Talen Energy Marketing, LLC, the successor name of PPL EnergyPlus, after the spinoff of PPL Energy Supply that marketed and traded wholesale and retail electricity and gas, and supplied energy and energy services in competitive markets, after the June 1, 2015 spinoff of PPL Energy Supply.

TCJA - Tax Cuts and Jobs Act. Comprehensive U.S. federal tax legislation enacted on December 22, 2017.

Total shareowner return - the change in market value of a share of the company's common stock plus the value of all dividends paid on a share of the common stock during the applicable performance period, divided by the price of the common stock as of the beginning of the performance period. The price used for purposes of this calculation is the average share price for the 20 trading days at the beginning and end of the applicable period.

Treasury Stock Method - a method applied to calculate diluted EPS that assumes any proceeds that could be obtained upon exercise of options and warrants (and their equivalents) would be used to purchase common stock at the average market price during the relevant period.

U.K. utility business - PPL WPD Investments Limited and its subsidiaries, including, notably, WPD plc and the four distribution network operators, which substantially represented PPL's U.K. Regulated segment. The U.K. utility business was sold on June 14, 2021.

UWUA - Utility Workers Union of America.

VEBA - Voluntary Employee Beneficiary Association. A tax-exempt trust under the Internal Revenue Code Section 501 (c)(9) used by employers to fund and pay eligible medical, life and similar benefits.

VSCC - Virginia State Corporation Commission, the state agency that has jurisdiction over the regulation of Virginia corporations, including utilities.

WPD - Prior to the sale of the U.K. utility business on June 14, 2021, refers to PPL WPD Investments Limited and its subsidiaries. WPD was included in the sale of the U.K. utility business on June 14, 2021.

WPD plc - Western Power Distribution plc, prior to the sale of the U.K utility business, a U.K. indirect subsidiary of PPL WPD Limited. Its principal indirectly owned subsidiaries are WPD (East Midlands), WPD (South Wales), WPD (South West) and WPD (West Midlands). WPD plc was included in the sale of the U.K. utility business on June 14, 2021.

1. Summary of Significant Accounting Policies

(All Registrants)

General

Capitalized terms and abbreviations appearing in the combined notes to financial statements are defined in the glossary. Dollars are in millions, except per share data, unless otherwise noted. The specific Registrant to which disclosures are applicable is identified in parenthetical headings in italics above the applicable disclosure or within the applicable disclosure for each Registrants' related activities and disclosures. Within combined disclosures, amounts are disclosed for any Registrant when significant.

Business and Consolidation

(PPL)

PPL is a utility holding company that, through its regulated subsidiaries, is primarily engaged in: 1) the generation, transmission, distribution and sale of electricity and the distribution and sale of natural gas, primarily in Kentucky; 2) the transmission, distribution and sale of electricity in Pennsylvania; and 3) the transmission, distribution and sale of electricity and the distribution and sale of natural gas in Rhode Island. Headquartered in Allentown, PA, PPL's principal subsidiaries are LG&E, KU, RIE and PPL Electric. PPL's corporate level financing subsidiary is PPL Capital Funding.

On March 17, 2021, PPL WPD Limited entered into a share purchase agreement to sell PPL's U.K. utility business, which prior to its sale substantially represented PPL's U.K. Regulated segment, to a subsidiary of National Grid plc. The sale was completed on June 14, 2021. The results of operations of the U.K. utility business are classified as Discontinued Operations on PPL's Statements of Income for 2022. PPL has elected to separately report the cash flows of continuing and discontinued operations on the Statements of Cash Flows for 2022. Unless otherwise noted, the notes to these financial statements exclude amounts related to discontinued operations. See Note 9 for additional information.

On May 25, 2022, PPL Rhode Island Holdings, a wholly-owned subsidiary of PPL, acquired 100% of the outstanding shares of common stock of Narragansett Electric from National Grid U.S., a subsidiary of National Grid plc. Narragansett Electric, whose service area covers substantially all of Rhode Island, is primarily engaged in the transmission, distribution and sale of electricity and the distribution and sale of natural gas. The results of Narragansett Electric are included in the consolidated results of PPL from the date of the acquisition. Following the closing of the acquisition, Narragansett Electric provides services doing business under the name Rhode Island Energy (RIE). See Note 9 for additional information.

(PPL and PPL Electric)

PPL Electric's principal business is the transmission and distribution of electricity to serve retail customers in its franchised territory in eastern and central Pennsylvania and the regulated supply of electricity to retail customers in that territory as a PLR.

(PPL, LG&E and KU)

LG&E and KU are engaged in the generation, transmission, distribution and sale of electricity. LG&E also engages in the distribution and sale of natural gas. LG&E and KU maintain their separate identities and serve customers in Kentucky under their respective names. KU also serves customers in Virginia under the Old Dominion Power name.

(All Registrants)

The financial statements of the Registrants include each company's own accounts as well as the accounts of all entities in which the company has a controlling financial interest. Entities for which a controlling financial interest is not demonstrated through voting interests are evaluated based on accounting guidance for Variable Interest Entities (VIEs). The Registrants consolidate a VIE when they are determined to have a controlling interest in the VIE and, as a result, are the primary beneficiary of the entity. Amounts consolidated under the VIE guidance are not material to the Registrants.

All significant intercompany transactions have been eliminated.

The financial statements of PPL, LG&E and KU include their share of any undivided interests in jointly owned facilities, as well as their share of the related operating costs of those facilities. See Note 11 for additional information.

Regulation

(All Registrants)

PPL Electric, RIE, LG&E and KU are cost-based rate-regulated utilities for which rates are set by regulators to enable PPL Electric, RIE, LG&E and KU to recover the costs of providing electric or gas service, as applicable, and to provide a reasonable return to shareholders. Base rates are generally established based on a future test period. As a result, the financial statements are subject to the accounting for certain types of regulation as prescribed by GAAP and reflect the effects of regulatory actions. Regulatory assets are recognized for the effect of transactions or events where future recovery of underlying costs is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise currently be charged to expense. Regulatory liabilities are recognized for amounts expected to be returned through future regulated customer rates. In certain cases, regulatory liabilities are recorded based on an understanding or agreement with the regulator that rates have been set to recover expected future costs, and the regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. The accounting for regulatory assets and regulatory liabilities is based on specific ratemaking decisions or precedent for each transaction or event as prescribed by the FERC or the applicable state regulatory commissions. See Note 7 for additional details regarding regulatory matters.

Accounting Records

The system of accounts for regulated entities is maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the applicable state regulatory commissions.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Loss Accruals

Potential losses are accrued when (1) information is available that indicates it is "probable" that a loss has been incurred, given the likelihood of uncertain future events and (2) the amount of loss can be reasonably estimated. Accounting guidance defines "probable" as cases in which "the future event or events are likely to occur." The Registrants continuously assess potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events. Loss accruals for environmental remediation are discounted when appropriate.

The accrual of contingencies that might result in gains is not recorded, unless realization is assured.

Earnings Per Share *(PPL)*

EPS is computed using the two-class method, which is an earnings allocation method for computing EPS that treats a participating security as having rights to earnings that would otherwise have been available to common shareowners. Share-based payment awards that provide recipients a non-forfeitable right to dividends or dividend equivalents are considered participating securities.

Price Risk Management

(All Registrants)

Interest rate contracts are used to hedge exposure to changes in the fair value of debt instruments and to hedge exposure to variability in expected cash flows associated with existing floating-rate debt instruments or forecasted fixed-rate issuances of debt. Derivative instruments pursuant to regulator approved plans to manage commodity price risk associated with natural gas purchases to reduce fluctuations in natural gas prices and costs associated with these derivatives instruments are generally recoverable through approved cost recovery mechanism. Similar derivatives may receive different accounting treatment, depending on management's intended use and documentation.

Certain contracts may not meet the definition of a derivative because they lack a notional amount or a net settlement provision. In cases where there is no net settlement provision, markets are periodically assessed to determine whether market mechanisms have evolved to facilitate net settlement. Certain derivative contracts may be excluded from the requirements of derivative accounting treatment because NPNS has been elected. These contracts are accounted for using accrual accounting. Contracts that have been classified as derivative contracts are reflected on the balance sheets at fair value.

Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing activities on the Statements of Cash Flows, depending on the classification of the hedged items.

PPL and its subsidiaries have elected not to offset net derivative positions against the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements.

Derivative transactions may be marked to fair value through regulatory assets/liabilities at PPL Electric, RIE, LG&E and KU, if approved by the appropriate regulatory body. These transactions generally include the effect of interest rate swaps or commodity gas contracts that are included in customer rates.

See Notes 15 and 16 for additional information on derivatives.

(PPL and PPL Electric)

To meet their obligations as last resort providers of electricity supply to their customers, PPL Electric and RIE have entered into certain contracts that meet the definition of a derivative. However, NPNS has been elected for these contracts.

Revenue *(All Registrants)*

Operating revenues are primarily recorded based on energy deliveries through the end of each calendar month. Unbilled retail revenues result because customers' bills are rendered throughout the month, rather than at the end of the month. For RIE, LG&E and KU, unbilled revenues for a month are calculated by multiplying an estimate of unbilled kWh or Mcf by the estimated average price per kWh or Mcf. Any difference between estimated and actual revenues is adjusted the following month when the previous unbilled estimate is reversed and actual billings occur. For PPL Electric, unbilled revenues for a month are calculated by multiplying the actual unbilled volumes by the applicable tariff price.
PPL Electric's, RIE's, LG&E's and KU's base rates are determined based on cost of service. Some regulators have also authorized the use of additional alternative revenue programs, which enable PPL Electric, RIE, LG&E and KU to adjust future rates based on past activities or completed events. Revenues from alternative revenue programs are recognized when the specific events permitting future billings have occurred. Revenues from alternative revenue programs are required to be presented separately from revenues from contracts with customers. These amounts are, however, presented as revenues from contracts with customers, with an offsetting adjustment to alternative revenue program revenue, when they are billed to customers in future periods. See Note 3 for additional information.

Financing and Other Receivables

(All Registrants)

Accounts receivable are reported on the Balance Sheets at the gross outstanding amount adjusted for an allowance for doubtful accounts. Financing receivables include accounts receivable, with the exception of those items within accounts receivable that are not subject to the current expected credit loss model.

Financing receivable collectability is evaluated using a current expected credit loss model, consisting of a combination of factors, including past due status based on contractual terms, trends in write-offs and the age of the receivable. Specific events, such as bankruptcies, are also considered when applicable. The Registrants also evaluate the impact of observable external factors on the collectability of the financing receivables to determine if adjustments to the allowance for doubtful accounts should be made based on current conditions or reasonable and supportable forecasts. Adjustments to the allowance for doubtful accounts are made based on the results of these analyses. Accounts receivable are written off in the period in which the receivable is deemed uncollectible.

PPL Electric, RIE, LG&E and KU have identified one class of financing receivables, “accounts receivable - customer”, which includes financing receivables for all billed and unbilled sales with customers. All other financing receivables are classified as other.

The changes in the allowance for doubtful accounts are included in the following table. Amounts relate to financing receivables, except as noted.

	Balance at Beginning of Period	Additions Charged to Income	Deductions (a)	Balance at End of Period
PPL				
2024	$ 130	$ 109	$ 85	$ 154 (c)
2023	95	87	52	130 (c)
2022	69	78	52	95 (c)
PPL Electric				
2024	$ 50	$ 56	$ 65	$ 41 (b)
2023	33	52	35	50 (b)
2022	35	27	29	33 (b)
LG&E				
2024	$ 6	$ 4	$ 7	$ 3
2023	4	4	2	6
2022	3	6	5	4
KU				
2024	$ 2	$ 4	$ 4	$ 2
2023	3	3	4	2
2022	3	6	6	3

(a) Primarily related to uncollectible accounts written off.
(b) Includes $2 million, $3 million and $3 million related to other accounts receivable at December 31, 2024, 2023 and 2022.
(c) Includes $39 million, $41 million and $36 million related to other accounts receivable at December 31, 2024, 2023 and 2022.

Cash

(All Registrants)

Cash Equivalents

All highly liquid investments with original maturities of three months or less are considered to be cash equivalents.

(PPL, LG&E and KU)

Restricted Cash and Cash Equivalents

Bank deposits and other cash equivalents that are restricted by agreement or that have been clearly designated for a specific purpose are classified as restricted cash and cash equivalents. On the Balance Sheets, the current portion of restricted cash and cash equivalents is included in "Other current assets," while the noncurrent portion is included in "Other noncurrent assets." See Note 15 for a reconciliation of Cash, Cash Equivalents and Restricted Cash reported within the Balance Sheets to the amounts shown on the Statements of Cash Flows.

(All Registrants)

Fair Value Measurements

The Registrants value certain financial and nonfinancial assets and liabilities at fair value. Generally, the most significant fair value measurements relate to price risk management assets and liabilities, investments in securities in defined benefit plans, and cash and cash equivalents. PPL and its subsidiaries use, as appropriate, a market approach (generally, data from market transactions), an income approach (generally, present value techniques and option-pricing models) and/or a cost approach (generally, replacement cost) to measure the fair value of an asset or liability. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk.

The Registrants classify fair value measurements within one of three levels in the fair value hierarchy. The level assigned to a fair value measurement is based on the lowest level input that is significant to the fair value measurement in its entirety. The three levels of the fair value hierarchy are as follows:

- **Level 1** - quoted prices (unadjusted) in active markets for identical assets or liabilities that are accessible at the measurement date. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

- **Level 2** - inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for substantially the full term of the asset or liability.

- **Level 3** - unobservable inputs that management believes are predicated on the assumptions market participants would use to measure the asset or liability at fair value.

Assessing the significance of a particular input requires judgment that considers factors specific to the asset or liability. As such, the Registrants' assessment of the significance of a particular input may affect how the assets and liabilities are classified within the fair value hierarchy.

Investments

Generally, the original maturity date of an investment and management's intent and ability to sell an investment prior to its original maturity determine the classification of investments as either short-term or long-term. Investments that would otherwise be classified as short-term, but are restricted as to withdrawal or use for other than current operations or are clearly designated for expenditure in the acquisition or construction of noncurrent assets or for the liquidation of long-term debts, are classified as long-term.

Investments in entities in which a company has the ability to exercise significant influence but does not have a controlling financial interest are accounted for under the equity method. All other investments are carried at cost or fair value. These investments are included in "Other noncurrent assets" on the Balance Sheets. Earnings from these investments are recorded in "Other Income (Expense) - net" on the Statements of Income.

Short-term investments generally include certain deposits as well as securities that are considered highly liquid or provide for periodic reset of interest rates. Investments with original maturities greater than three months and less than a year, as well as investments with original maturities of greater than a year that management has the ability and intent to sell within a year, are included in "Other current assets" on the Balance Sheets.

Long-Lived and Intangible Assets

Property, Plant and Equipment

PP&E is recorded at original cost, unless impaired. If impaired, the asset is written down to fair value at that time, which becomes the new cost basis of the asset. PP&E acquired in business combinations is recorded at fair value at the time of acquisition. Original cost for constructed assets includes material, labor, contractor costs, certain overheads and financing costs, where applicable. Included in PP&E are capitalized costs of software projects that were developed or obtained for internal use. The cost of repairs and minor replacements are charged to expense as incurred. The Registrants record costs associated with planned major maintenance projects in the period in which work is performed and costs are incurred.

AFUDC is capitalized at PPL Electric and RIE as part of the construction costs for cost-based rate-regulated projects for which a return on such costs is recovered after the project is placed in service. AFUDC is capitalized at LG&E and KU for certain projects as part of the construction cost of approved projects. LG&E and KU are generally provided a return on construction work in progress for other projects. The debt component of AFUDC is credited to "Interest Expense" and the equity component is credited to "Other Income (Expense) - net" on the Statements of Income.

The Registrants capitalize interest costs as part of construction costs. Capitalized interest, including the debt component of AFUDC, for the years ended December 31 is as follows:

	2024	2023	2022
PPL	$ 20	$ 12	$ 7
PPL Electric	9	7	5
LG&E	3	1	—
KU	4	1	—

Depreciation

Depreciation is recorded over the estimated useful lives of property using various methods including the straight-line, composite and group methods. When a component of PP&E that was depreciated under the composite or group method is retired, the original cost is charged to accumulated depreciation. When all or a significant portion of an operating unit that was depreciated under the composite or group method is retired or sold, the property and the related accumulated depreciation account is reduced and any gain or loss is included in income, unless otherwise required by regulators. RIE, LG&E and KU accrue costs of removal net of estimated salvage value through depreciation, which is included in the calculation of customer rates over the assets' depreciable lives in accordance with regulatory practices. Cost of removal amounts accrued through depreciation rates are accumulated as a regulatory liability until the removal costs are incurred. For LG&E and KU, all ARO depreciation expenses are reclassified to a regulatory asset or regulatory liability. See "Asset Retirement Obligations" below and Note 7 for additional information. PPL Electric records net costs of removal when incurred as a regulatory asset. The regulatory asset is subsequently amortized through depreciation over a five-year period, which is recoverable in customer rates in accordance with regulatory practices.

Following are the weighted-average annual rates of depreciation, for regulated utility plant, for the years ended December 31:

	2024		2023		2022	
PPL	3.20	%	3.26	%	3.21	%
PPL Electric	2.52	%	2.62	%	2.75	%
LG&E	4.02	%	4.00	%	4.16	%
KU	3.86	%	3.95	%	4.01	%

Goodwill and Other Intangible Assets

Goodwill represents the excess of the purchase price paid over the fair value of the identifiable net assets acquired in a business combination.

Other acquired intangible assets are initially measured based on their fair value. Intangibles that have finite useful lives are amortized over their useful lives based upon the pattern in which the economic benefits of the intangible assets are consumed or otherwise used. Costs incurred to obtain, renew or extend terms of an intangible asset are capitalized.

When determining the useful life of an intangible asset, including intangible assets that are renewed or extended, PPL and its subsidiaries consider:

- the expected use of the asset;
- the expected useful life of other assets to which the useful life of the intangible asset may relate;
- legal, regulatory, or contractual provisions that may limit the useful life;
- the company's historical experience as evidence of its ability to support renewal or extension;
- the effects of obsolescence, demand, competition, and other economic factors; and,
- the level of maintenance expenditures required to obtain the expected future cash flows from the asset.

Asset Impairment (Excluding Investments)

The Registrants review long-lived assets that are subject to depreciation or amortization, including finite-lived intangibles, for impairment when events or circumstances indicate carrying amounts may not be recoverable.

A long-lived asset classified as held and used is impaired when the carrying amount of the asset exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If impaired, the asset's carrying value is written down to its fair value.

A long-lived asset classified as held for sale is impaired when the carrying amount of the asset (disposal group) exceeds its fair value less cost to sell. If impaired, the asset's (disposal group's) carrying value is written down to its fair value less cost to sell.

PPL, LG&E and KU review goodwill for impairment at the reporting unit level annually or more frequently when events or circumstances indicate that the carrying amount of a reporting unit may be greater than the unit's fair value. Additionally, goodwill must be tested for impairment in circumstances when a portion of goodwill has been allocated to a business to be disposed. PPL's, LG&E's and KU's reporting units are primarily at the operating segment level.
Goodwill recognized upon the acquisition of Narragansett Electric was assigned for impairment testing by PPL to its reporting units expected to benefit from the acquisition, which were the Rhode Island Regulated reporting unit, the Pennsylvania Regulated reporting unit and the Kentucky Regulated reporting unit. See Note 9 for additional information regarding the acquisition.

PPL, for its reporting units, and individually, LG&E and KU, may elect either to initially make a qualitative evaluation about the likelihood of an impairment of goodwill or to bypass the qualitative evaluation and test goodwill for impairment using a quantitative test. If the qualitative evaluation (referred to as step zero) is elected and the assessment results in a determination that it is not more likely than not that the fair value of a reporting unit is less than the carrying amount, the quantitative impairment test is not necessary. However, the quantitative impairment test is required if management concludes it is more likely than not that the fair value of a reporting unit is less than the carrying amount based on the step zero assessment. If the carrying amount of the reporting unit, including goodwill, exceeds its fair value, an impairment loss is recognized in an amount equal to that excess, limited to the total amount of goodwill allocated to that reporting unit.

As of October 1, 2024, PPL, for its reporting units, and individually, LG&E and KU, elected to perform the qualitative step zero evaluation of goodwill. These evaluations considered the excess of fair value over the carrying value of each reporting unit that was calculated during step one of the quantitative impairment tests performed in the fourth quarter of 2022, and the relevant events and circumstances that occurred since those tests were performed including:

- current year financial performance versus the prior year,
- changes in planned capital expenditures,
- the consistency of forecasted free cash flows,
- earnings quality and sustainability,
- changes in market participant discount rates,
- changes in long-term growth rates,
- changes in PPL's market capitalization, and
- the overall economic and regulatory environments in which these regulated entities operate.

Based on these evaluations, management concluded it was not more likely than not that the fair value of these reporting units was less than their carrying value. As such, the step one quantitative impairment test was not performed and no impairment was recognized.

(*PPL, LG&E and KU*)

Asset Retirement Obligations

PPL and its subsidiaries record liabilities to reflect various legal obligations associated with the retirement of long-lived assets. Initially, this obligation is measured at fair value and offset with an increase in the value of the capitalized asset, which is depreciated over the asset's useful life. Until the obligation is settled, the liability is increased through the recognition of accretion expense classified within "Other operation and maintenance" on the Statements of Income to reflect changes in the obligation due to the passage of time. For LG&E and KU, all ARO accretion and depreciation expenses are reclassified as a regulatory asset or regulatory liability. ARO regulatory assets associated with certain CCR projects are amortized to expense in accordance with regulatory approvals. For other AROs, deferred accretion and depreciation expense is recovered through cost of removal.

Estimated ARO costs and settlement dates, which affect the carrying value of the ARO and the related capitalized asset, are reviewed periodically to ensure that any material changes are incorporated into the latest estimate of the ARO. Any change to the capitalized asset, positive or negative, is generally amortized over the remaining life of the associated long-lived asset. See Note 7 and Note 18 for additional information on AROs.

Compensation and Benefits

Defined Benefits *(All Registrants)*

Certain PPL subsidiaries sponsor various defined benefit pension and other postretirement plans. An asset or liability is recorded to recognize the funded status of all defined benefit plans with an offsetting entry to AOCI or, for LG&E, KU, RIE and PPL Electric, to regulatory assets or liabilities. Consequently, the funded status of all defined benefit plans is fully recognized on the Balance Sheets.

The expected return on plan assets is determined based on a market-related value of plan assets, which is calculated by rolling forward the prior year market-related value with contributions, disbursements and long-term expected return on investments. One-fifth of the difference between the actual value and the expected value is added (or subtracted if negative) to the expected value to determine the new market-related value.

PPL and its subsidiaries, excluding RIE, use an accelerated amortization method for the recognition of gains and losses for its defined benefit pension plans. Under the accelerated method, actuarial gains and losses in excess of 30% of the plan's projected benefit obligation are amortized on a straight-line basis over one-half of the required amortization period. Actuarial gains and losses in excess of 10% of the greater of the plan's projected benefit obligation or the market-related value of plan assets and less than 30% of the plan's projected benefit obligation are amortized on a straight-line basis over the full required amortization period. RIE uses the standard amortization method under GAAP for recognition of gains and losses for its defined benefit pension plan.

See Note 7 for a discussion of the regulatory treatment of defined benefit costs and Note 10 for a discussion of defined benefits.

Stock-Based Compensation *(PPL)*

PPL has several stock-based compensation plans for purposes of granting stock options, restricted stock, restricted stock units and performance units to certain employees as well as stock units and restricted stock units to directors. PPL grants most stock-based compensation awards in the first quarter of each year. PPL recognizes compensation expense for stock-based compensation awards based on the fair value method. Forfeitures of awards are recognized when they occur. All awards are recorded as equity or a liability on the Balance Sheets. Stock-based compensation expense is primarily included in "Other operation and maintenance" on the Statements of Income.

Taxes

Income Taxes

(All Registrants)

PPL and its domestic subsidiaries file a consolidated U.S. federal income tax return.

Significant management judgment is required in developing the Registrants' provision for income taxes, primarily due to the uncertainty related to tax positions taken or expected to be taken on tax returns and valuation allowances on deferred tax assets.

The Registrants use a two-step process to evaluate uncertain tax positions. The first step requires an entity to determine whether, based on the technical merits supporting a particular tax position, it is more likely than not (greater than a 50% chance) that the tax position will be sustained. This determination assumes that the relevant taxing authority will examine the tax position and is aware of all the relevant facts surrounding the tax position. The second step requires an entity to recognize in its financial statements the amount of the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization upon settlement that exceeds 50%. Unrecognized tax benefits are classified as current to the extent management expects to settle the uncertain tax position by payment or receipt of cash within one year of the reporting date. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact the financial statements of the Registrants in future periods. At December 31, 2024, no significant changes in unrecognized tax benefits were projected over the next 12 months.

Deferred income taxes reflect the net future tax effects of temporary differences between the carrying amounts of assets and liabilities for accounting purposes and their basis for income tax purposes, as well as the tax effects of net operating losses and tax credit carryforwards.

The Registrants record valuation allowances to reduce deferred income tax assets to the amounts that are more-likely-than-not to be realized. The need for valuation allowances requires significant management judgment. If the Registrants determine that they are able to realize deferred tax assets in the future in excess of recorded net deferred tax assets, adjustments to the valuation allowances increase income by reducing tax expense in the period that such determination is made. Likewise, if the Registrants determine that they are not able to realize all or part of net deferred tax assets in the future, adjustments to the valuation allowances would decrease income by increasing tax expense in the period that such determination is made. The amount of deferred tax assets ultimately realized may differ materially from the estimates utilized in the computation of valuation allowances and may materially impact the financial statements in the future.

The Registrants defer investment tax credits when the credits are generated and amortize the deferred amounts over the average lives of the related assets. With respect to acquired renewable tax credits, pursuant to the IRA, any benefit is recognized in the period the credits can be utilized.

The Registrants recognize tax-related interest and penalties in "Income Taxes" on their Statements of Income.

The Registrants use the portfolio approach method of accounting for deferred taxes related to pre-tax OCI transactions. The portfolio approach involves a strict period-by-period cumulative incremental allocation of income taxes to the change in income and losses reflected in OCI. Under this approach, the net cumulative tax effect is ignored. The net change in unrealized gains and losses recorded in AOCI under this approach would be eliminated only on the date the investment portfolio is classified as held for sale or is liquidated.

See Note 6 to the Financial Statements for income tax disclosures.

The provision for the Registrants' deferred income taxes related to regulatory assets and liabilities is based upon the ratemaking principles reflected in rates established by relevant regulators. The difference in the provision for deferred income taxes for regulatory assets and liabilities and the amount that otherwise would be recorded under GAAP is deferred and included on the Balance Sheets in noncurrent "Regulatory assets" or "Regulatory liabilities."

(PPL Electric, LG&E and KU)

The income tax provision for PPL Electric, LG&E and KU is calculated in accordance with an intercompany tax sharing agreement, which provides that taxable income be calculated as if PPL Electric, LG&E, KU and any domestic subsidiaries each filed a separate return. Tax benefits are not shared between companies. The entity that generates a tax benefit is the entity that is entitled to the tax benefit. The effect of PPL filing a consolidated tax return is taken into account in the settlement of current taxes and the recognition of deferred taxes.

At December 31, the following intercompany tax receivables (payables) were recorded:

	2024	2023
PPL Electric	$ (2)	$ (21)
LG&E	(2)	(5)
KU	(5)	(3)

Taxes, Other Than Income *(All Registrants)*

The Registrants present sales taxes in "Other current liabilities" on the Balance Sheets. These taxes are not reflected on the Statements of Income. See Note 6 for details of taxes included in "Taxes, other than income" on the Statements of Income.

Other

(All Registrants)

Fuel, Materials and Supplies

Fuel, natural gas stored underground and materials and supplies are valued using the average cost method. Fuel costs for electricity generation are charged to expense as used. For RIE, natural gas supply costs are charged to expense when delivered to customers. For LG&E, natural gas supply costs are charged to expense as delivered to the distribution system. See Note 7 for further discussion of the fuel adjustment clauses and gas supply clause.

"Fuel, materials and supplies" on the Balance Sheets consisted of the following at December 31:

	2024			
	PPL	PPL Electric	LG&E	KU
Fuel	$ 153	$ —	$ 64	$ 89
Natural gas stored underground	49	—	29	—
Materials and supplies	309	104	64	84
Total	$ 511	$ 104	$ 157	$ 173

	2023			
	PPL	PPL Electric	LG&E	KU
Fuel	$ 144	$ —	$ 50	$ 94
Natural gas stored underground	58	—	34	—
Materials and supplies	303	99	59	91
Total	$ 505	$ 99	$ 143	$ 185

(PPL and PPL Electric)

Renewable Energy Standard Obligation

Purchased Renewable Energy Certificates (RECs) are stated at cost and are used to measure compliance with state renewable energy standards. RECs support new renewable generation standards and are held primarily to be utilized in fulfillment of RIE’s and PPL Electric's compliance obligations.

(All Registrants)

Guarantees

Generally, the initial measurement of a guarantee liability is the fair value of the guarantee at its inception. However, there are certain guarantees excluded from the scope of accounting guidance and other guarantees that are not subject to the initial recognition and measurement provisions of accounting guidance that only require disclosure. See Note 12 for further discussion of guarantees.

New Accounting Guidance Adopted *(All Registrants)*

Improvements to Reportable Segment Disclosures

Effective December 31, 2024, the Registrants retrospectively adopted accounting guidance to improve segment disclosures. The guidance requires enhanced disclosures about significant segment expenses. The standard also requires public entities to disclose the title and position of the Chief Operating Decision Maker (CODM) and explain how the CODM uses the reported measure(s) of segment profit or loss in assessing segment performance and deciding how to allocate resources. Certain segment-related disclosures that previously were required only on an annual basis will be required to be disclosed in interim periods. In addition, public entities that have a single reportable segment are now required to provide segment disclosures.

The adoption of this guidance resulted in the Registrants including the required additional disclosures within the notes to the financial statements. See Note 2 for additional information.

2. Segment and Related Information

(PPL)

PPL is organized into three segments, broken down by geographic location: Kentucky Regulated, Pennsylvania Regulated, and Rhode Island Regulated.

The Kentucky Regulated segment consists primarily of the regulated electricity generation, transmission and distribution operations conducted by LG&E and KU, as well as LG&E's regulated transmission, distribution and sale of natural gas.

The Pennsylvania Regulated segment includes the regulated electricity transmission and distribution operations of PPL Electric.

The Rhode Island Regulated segment includes the regulated electricity transmission and distribution and natural gas distribution operations of RIE, which was acquired in May of 2022.

"Corporate and Other" primarily includes corporate level financing costs, certain unallocated corporate costs, and certain non-recoverable costs incurred in conjunction with the acquisition of Rhode Island Energy and the financial results of Safari Energy, prior to its sale on November 1, 2022. "Corporate and Other" is presented to reconcile segment information to PPL's consolidated results and is not a reportable segment.

PPL's CODM is the Corporate Leadership Council (CLC), which is a management committee that is comprised of the Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, Chief Technology Officer, Chief Human Resources Officer and Chief Legal Officer.

The CLC uses financial metrics including segment net income, earnings from ongoing operations, earnings per share and return on equity, as well as various operational metrics to assess segment performance and make investment and resource decisions. Segment net income is the measure of segment profit or loss that most closely aligns with GAAP and is being presented for disclosure purposes.

The tables below provide information about PPL’s segments and include the reconciliation to consolidated net income for the year ended December 31, 2024:

	Kentucky Regulated	Pennsylvania Regulated	Rhode Island Regulated	Total
Operating Revenues from external customers (a)	$ 3,562	$ 2,876	$ 2,024	$ 8,462
Reconciliation of revenue				
Corporate and other revenues				—
Total consolidated revenues				$ 8,462
Less:				
Fuel	783	—	—	783
Energy Purchases	176	721	782	1,679
Operation and maintenance	803	705	731	2,239
Depreciation	710	401	165	1,276
Taxes, other than income	99	131	144	374
Other (income) expense - net	(29)	(78)	(24)	(131)
Interest expense	240	246	95	581
Income taxes	160	176	22	358
Segment net income	$ 620	$ 574	$ 109	$ 1,303
Reconciliation of segment profit or loss to consolidated net income				
Corporate and other net loss				(415)
Net Income				$ 888

(a) See Note 1 and Note 3 for additional information on Operating Revenues.

Other information for the segments and reconciliation to PPL's Consolidated results for the year ended December 31, 2024 are as follows:

	Kentucky Regulated	Pennsylvania Regulated	Rhode Island Regulated	Total Segments	Corporate and Other	Consolidated Total
Other Segment Disclosures						
Amortization (a)	$ 24	$ 45	$ 1	$ 70	$ 8	$ 78
Deferred income taxes and investment tax credits (b)	3	129	38	170	26	196
Expenditures for long lived assets	1,088	1,229	512	2,829	(8)	2,821

(a) Represents non-cash expense items that include amortization of operating lease right-of-use assets, regulatory assets and liabilities, debt discounts and premiums and debt issuance costs.
(b) Represents a non-cash expense item that is also included in "Income Taxes."

The tables below provide information about PPL's segments and include the reconciliation to consolidated net income for the year ended December 31, 2023:

	Kentucky Regulated	Pennsylvania Regulated	Rhode Island Regulated	Total
Operating Revenues from external customers (a)	$ 3,452	$ 3,008	$ 1,851	$ 8,311
Reconciliation of revenue				
Corporate and other revenues				1
Total consolidated revenues				$ 8,312
Less:				
Fuel	733	—	—	733
Energy Purchases	192	992	658	1,842
Operation and maintenance	826	605	705	2,136
Depreciation	696	397	156	1,249
Taxes, other than income	93	143	156	392
Other (income) expense - net	(12)	(39)	(19)	(70)
Interest expense	235	223	83	541
Income taxes	137	168	16	321
Segment net income	$ 552	$ 519	$ 96	$ 1,167
Reconciliation of segment profit or loss to consolidated net income				
Corporate and other net loss				(427)
Net Income				$ 740

(a) See Note 1 and Note 3 for additional information on Operating Revenues.

Other information for the segments and reconciliation to PPL's Consolidated results for the year ended December 31, 2023 are as follows:

	Kentucky Regulated	Pennsylvania Regulated	Rhode Island Regulated	Total Segments	Corporate and Other	Consolidated Total
Other Segment Disclosures						
Amortization (a)	$ 33	$ 41	$ 1	$ 75	$ 6	$ 81
Deferred income taxes and investment tax credits (b)	(17)	46	48	77	245	322
Expenditures for long lived assets	950	956	454	2,360	30	2,390

(a) Represents non-cash expense items that include amortization of operating lease right-of-use assets, regulatory assets and liabilities, debt discounts and premiums and debt issuance costs.
(b) Represents a non-cash expense item that is also included in "Income Taxes."

The tables below provide information about PPL's segments and include the reconciliation to consolidated net income for the year ended December 31, 2022:

	Kentucky Regulated	Pennsylvania Regulated	Rhode Island Regulated	Total
Operating Revenues from external customers (a)	$ 3,811	$ 3,030	$ 1,038	$ 7,879
Reconciliation of revenue				
Corporate and other revenues				23
Total consolidated revenues				$ 7,902
Less:				
Fuel	931	—	—	931
Energy Purchases	273	1,048	365	1,686
Operation and maintenance	959	605	531	2,095
Depreciation	685	393	92	1,170
Taxes, other than income	92	149	92	333
Other (income) expense - net	(12)	(35)	(23)	(70)
Interest expense	205	171	39	415
Income taxes	129	174	(14)	289
Segment net income	$ 549	$ 525	$ (44)	$ 1,030
Reconciliation of segment profit or loss to consolidated net income				
Corporate and other net loss				(316)
Income from discontinued operations (Note 9)				42
Net Income				$ 756

(a) See Note 1 and Note 3 for additional information on Operating Revenues.

Other information for the segments and reconciliation to PPL's Consolidated results for the year ended December 31, 2022 are as follows:

	Kentucky Regulated	Pennsylvania Regulated	Rhode Island Regulated	Total Segments	Corporate and Other	Consolidated Total
Other Segment Disclosures						
Amortization (a)	$ 23	$ 22	$ 2	$ 47	$ 5	$ 52
Deferred income taxes and investment tax credits (b)	6	91	39	136	43	179
Expenditures for long lived assets	917	889	268	2,074	84	2,158

(a) Represents non-cash expense items that include amortization of operating lease right-of-use assets, regulatory assets and liabilities, debt discounts and premiums and debt issuance costs.
(b) Represents a non-cash expense item that is also included in "Income Taxes."

The following provides Balance Sheet data for the segments and reconciliation to PPL's consolidated results as of:

	As of December 31,	
	2024	2023
Total Assets		
Kentucky Regulated	$ 17,626	$ 17,029
Pennsylvania Regulated	15,475	14,294
Rhode Island Regulated	7,083	6,515
Corporate and Other (a)	885	1,398
Total	$ 41,069	$ 39,236

(a) Primarily consists of unallocated items, including cash, PP&E, goodwill, and the elimination of inter-segment transactions.

(PPL Electric)

PPL Electric has two operating segments, distribution and transmission, which are aggregated into a single reportable segment. PPL Electric's CODM is the President of PPL Electric.
The President uses financial metrics including segment net income, earnings from ongoing operations, earnings per share and return on equity, as well as various operational metrics to assess segment performance and make investment and resource decisions.

The significant segment expenses of and measure of profit and loss for PPL Electric regularly provided to the President are included on the face of PPL Electric's Statements of Income.

The measure of segment assets is reported on PPL Electric's Balance Sheets as total consolidated assets. The measures of significant non-cash segment expenses as well as expenditures for long lived assets are reported on PPL Electric's Statements of Cash Flows.

(LG&E and KU)

Each of LG&E and KU operates as a single operating and reportable segment, and the CODM for each of LG&E and KU is its President.

The President manages LG&E and KU as a single consolidated entity. Financial metrics including net income, earnings from ongoing operations, earnings per share and return on equity, as well as various operational metrics are used to assess segment performance and make investment and resource decisions.

The significant segment expenses of and measure of profit and loss for each of LG&E and KU regularly provided to its President are included on the face of the Statements of Income of LG&E and KU.

The measures of segment assets are reported on the Balance Sheets of LG&E and KU as total assets. The measures of significant non-cash segment expenses as well as expenditures for long lived assets are reported on the Statements of Cash Flows of LG&E and KU.

3. Revenue from Contracts with Customers

(All Registrants)

The following is a description of the principal activities from which the Registrants and PPL's segments generate their revenues.

(PPL and PPL Electric)

Pennsylvania Regulated Segment Revenue

The Pennsylvania Regulated segment generates substantially all of its revenues from contracts with customers from PPL Electric's tariff-based distribution and transmission of electricity.

Distribution Revenue

PPL Electric provides distribution services to residential, commercial, industrial, municipal and governmental end users of energy. PPL Electric satisfies its performance obligation to its distribution customers and revenue is recognized over time as electricity is delivered and simultaneously consumed by the customer. The amount of revenue recognized is the volume of electricity delivered during the period multiplied by the price per tariff, plus a monthly fixed charge. This method of recognition fairly presents PPL Electric's transfer of electric service to the customer as the calculation is based on volumes delivered, and the price per tariff and the monthly fixed charge are set by the PAPUC. Customers are typically billed monthly and outstanding amounts are normally due within 21 days of the date of the bill.

Distribution customers are "at will" customers of PPL Electric with no term contract and no minimum purchase commitment. Performance obligations are limited to the service requested and received to date. Accordingly, there is no unsatisfied performance obligation associated with PPL Electric's retail account contracts.

Certain customers have the option to obtain electricity from other suppliers where PPL Electric facilitates the delivery. In those circumstances, revenue is only recognized for providing delivery of the commodity to the customer.

Transmission Revenue

PPL Electric generates transmission revenues from a FERC-approved PJM Open Access Transmission Tariff. An annual revenue requirement for PPL Electric to provide transmission services is calculated using a formula-based rate. This revenue requirement is converted into a daily rate (dollars per day). PPL Electric satisfies its performance obligation to provide transmission services and revenue is recognized over time as transmission services are provided and consumed. This method of recognition fairly presents PPL Electric's transfer of transmission services as the daily rate is set by a FERC approved formula-based rate. PJM remits payment on a weekly basis.

PPL Electric's agreement to provide transmission services contains no minimum purchase commitment. The performance obligation is limited to the service requested and received to date. Accordingly, PPL Electric has no unsatisfied performance obligations.

(PPL)

Rhode Island Regulated Segment Revenues

The Rhode Island Regulated segment generates substantially all of its revenues from contracts with customers from RIE's regulated tariff-based transmission and distribution of electricity and regulated tariff-based distribution of natural gas.

Distribution Revenue

Distribution revenues are primarily from the sale of electricity, natural gas, and related services to retail customers. Distribution sales are regulated by the RIPUC, which is responsible for approving the rates and other terms of services as part of the rate making process. Natural gas and electric distribution revenues are derived from the regulated sale and distribution of electricity and natural gas to residential, commercial, and industrial customers within RIE's service territory under the tariff rates. The performance obligation related to distribution sales is to provide electricity and natural gas to customers on demand. The performance obligation is satisfied over time because the customer simultaneously receives and consumes the electricity or natural gas as services are provided. RIE records revenues related to the distribution sales based upon the approved tariff rate and the volume delivered to the customers, which corresponds with the amount RIE has the right to invoice. Customers are typically billed monthly and outstanding amounts are normally due within 21 days of date of the bill.

Distribution revenue also includes estimated unbilled amounts, which represent the estimated amounts due from retail customers as a result of customer's bills rendered throughout the month, rather than bills being rendered at the end of the month. Unbilled revenues are determined based on estimated unbilled sales volumes and then applying tariff rates to those volumes. Any difference between estimated and actual revenues is adjusted the following month when the previous unbilled estimate is reversed and actual billings occur. This method of recognition fairly presents RIE's transfer of electricity and natural gas to the customer as the amount recognized is based on actual and estimated volumes delivered and the tariff rate per unit of energy and any applicable fixed charges or regulatory mechanisms as approved by the respective regulatory body.

Distribution customers are "at will" customers of RIE with no term contract and no minimum purchase commitment. Performance obligations are limited to the service requested and received to date. Accordingly, there is no unsatisfied performance obligation associated with RIE's retail account contracts.

Certain customers have the option to obtain electricity or natural gas from other suppliers where RIE facilitates the delivery. In those circumstances, revenue is only recognized for providing delivery of the commodity to the customer.

Transmission Revenue

RIE's transmission services are regulated by the FERC and coordinated with ISO – New England (ISO-NE). As of January 1, 2023, RIE is a transmission operator. These revenues arise under tariff/rate agreements and are collected primarily from RIE's distribution customers. The revenue is recognized over time as transmission services are provided and consumed. This method of recognition fairly presents RIE's transfer of transmission services as the daily rate is set by a FERC-approved formula-based rate.

RIE's agreement to provide transmission services contains no minimum purchase commitment. The performance obligation is limited to the service requested and received to date. Accordingly, RIE has no unsatisfied performance obligations.

(PPL, LG&E and KU)

Kentucky Regulated Segment Revenue

The Kentucky Regulated Segment generates substantially all of its revenues from contracts with customers from LG&E's and KU's regulated tariff-based sales of electricity and LG&E's regulated tariff-based sales of natural gas.

LG&E and KU are engaged in the generation, transmission, distribution and sale of electricity in Kentucky and, in KU's case, Virginia. LG&E also engages in the distribution and sale of natural gas in Kentucky. Revenue from these activities is generated from tariffs approved by applicable regulatory authorities including the FERC, KPSC and VSCC. LG&E and KU satisfy their performance obligations upon LG&E's and KU's delivery of electricity and LG&E's delivery of natural gas to customers. This
revenue is recognized over time as the customer simultaneously receives and consumes the benefits provided by LG&E and KU. The amount of revenue recognized is the billed volume of electricity or natural gas delivered multiplied by a tariff rate per-unit of energy, plus any applicable fixed charges or additional regulatory mechanisms. Customers are billed monthly and outstanding amounts are typically due within 22 days of the date of the bill. Additionally, unbilled revenues are recognized as a result of customers' bills rendered throughout the month, rather than bills being rendered at the end of the month. Unbilled revenues for a month are calculated by multiplying an estimate of unbilled kWh or Mcf delivered but not yet billed by the estimated average cents per kWh or Mcf. Any difference between estimated and actual revenues is adjusted the following month when the previous unbilled estimate is reversed and actual billings occur. This method of recognition fairly presents LG&E's and KU's transfer of electricity and LG&E's transfer of natural gas to the customer as the amount recognized is based on actual and estimated volumes delivered and the tariff rate per-unit of energy and any applicable fixed charges or regulatory mechanisms as set by the respective regulatory body.

LG&E's and KU's customers generally have no minimum purchase commitment. Performance obligations are limited to the service requested and received to date. Accordingly, there is no unsatisfied performance obligation associated with these customers.

(All Registrants)

The following table reconciles "Operating Revenues" included in each Registrant's Statement of Income with revenues generated from contracts with customers for the years ended December 31:

	2024			
	PPL	PPL Electric	LG&E	KU
Operating Revenues (a)(b)	$ 8,462	$ 2,876	$ 1,648	$ 1,964
Revenues derived from:				
Alternative revenue programs (c)	5	(19)	13	16
Other (d)	(23)	(15)	(4)	(4)
Revenues from Contracts with Customers	$ 8,444	$ 2,842	$ 1,657	$ 1,976

	2023			
	PPL	PPL Electric	LG&E	KU
Operating Revenues (a)(b)	$ 8,312	$ 3,008	$ 1,613	$ 1,884
Revenues derived from:				
Alternative revenue programs (c)	1	5	(1)	(5)
Other (d)	(23)	(15)	(4)	(4)
Revenues from Contracts with Customers	$ 8,290	$ 2,998	$ 1,608	$ 1,875

	2022			
	PPL	PPL Electric	LG&E	KU
Operating Revenues (a)(b)	$ 7,902	$ 3,030	$ 1,798	$ 2,074
Revenues derived from:				
Alternative revenue programs (c)	(92)	(56)	9	5
Other (d)	(24)	(14)	(6)	(4)
Revenues from Contracts with Customers	$ 7,786	$ 2,960	$ 1,801	$ 2,075

(a) PPL includes $2,024 million, $1,851 million and $1,038 million for the twelve months ended December 31, 2024, 2023, and 2022 of revenues from external customers reported by the Rhode Island Regulated segment. PPL Electric represents revenues from external customers reported by the Pennsylvania Regulated segment and LG&E and KU, net of intercompany power sales and transmission revenues, represent revenues from external customers reported by the Kentucky Regulated segment. See Note 2 for additional information.
(b) PPL's transition services agreement associated with the RIE acquisition ended in the third quarter of 2024. In conjunction with the completion of the agreement, PPL conformed the presentation of RIE's and the Rhode Island Regulated segment's net metering charges with the presentation of the other segments, resulting in an increase in Operating Revenues and a corresponding increase in Energy purchases beginning on January 1, 2024. For the year ended December 31, 2024, net metering of $175 million was included in Energy purchases on PPL's Statement of Income. For the years ended December 31, 2023 and 2022, $146 million and $79 million of net metering was presented as a reduction of Operating Revenues on PPL's Statement of Income.
(c) This line item shows the over/under collection of rate mechanisms deemed alternative revenue programs with over-collections of revenue shown as positive amounts in the table above and under collections as negative amounts.
(d) Represents additional revenues outside the scope of revenues from contracts with customers such as leases and other miscellaneous revenues.

The following table shows revenues from contracts with customers disaggregated by customer class for the years ended December 31:

	Residential	Commercial	Industrial	Other (a)	Wholesale - municipality	Wholesale - other (b)	Transmission	Revenues from Contracts with Customers
PPL								
2024								
PA Regulated	$ 1,502	$ 418	$ 47	$ 57	$ —	$ —	$ 818	$ 2,842
RI Regulated (c)	1,150	593	91	10	—	—	176	2,020
KY Regulated	1,510	1,028	635	323	23	63	—	3,582
Total PPL	$ 4,162	$ 2,039	$ 773	$ 390	$ 23	$ 63	$ 994	$ 8,444
2023								
PA Regulated	$ 1,649	$ 444	$ 55	$ 54	$ —	$ —	$ 796	$ 2,998
RI Regulated	640	228	20	793	—	—	170	1,851
KY Regulated	1,458	1,001	637	272	22	50	—	3,440
Corp and Other	—	—	—	1	—	—	—	1
Total PPL	$ 3,747	$ 1,673	$ 712	$ 1,120	$ 22	$ 50	$ 966	$ 8,290
2022								
PA Regulated	$ 1,647	$ 491	$ 85	$ 54	$ —	$ —	$ 683	$ 2,960
RI Regulated	299	101	9	478	—	—	101	988
KY Regulated	1,637	1,068	662	323	28	97	—	3,815
Corp and Other	—	—	—	23	—	—	—	23
Total PPL	$ 3,583	$ 1,660	$ 756	$ 878	$ 28	$ 97	$ 784	$ 7,786
PPL Electric								
2024	$ 1,502	$ 418	$ 47	$ 57	$ —	$ —	$ 818	$ 2,842
2023	$ 1,649	$ 444	$ 55	$ 54	$ —	$ —	$ 796	$ 2,998
2022	$ 1,647	$ 491	$ 85	$ 54	$ —	$ —	$ 683	$ 2,960
LG&E								
2024	$ 754	$ 518	$ 188	$ 147	$ —	$ 50	$ —	$ 1,657
2023	$ 751	$ 517	$ 189	$ 104	$ —	$ 47	$ —	$ 1,608
2022	$ 835	$ 551	$ 199	$ 141	$ —	$ 75	$ —	$ 1,801
KU								
2024	$ 756	$ 510	$ 447	$ 176	$ 23	$ 64	$ —	$ 1,976
2023	$ 707	$ 484	$ 448	$ 168	$ 22	$ 46	$ —	$ 1,875
2022	$ 802	$ 517	$ 463	$ 182	$ 28	$ 83	$ —	$ 2,075

(a) Primarily includes revenues from pole attachments, street lighting, other public authorities and other non-core businesses. For the years ended December 31, 2023 and 2022, the Rhode Island Regulated segment primarily includes open access tariff revenues, which are calculated on combined customer classes.
(b) Includes wholesale power and transmission revenues. LG&E and KU amounts include intercompany power sales and transmission revenues, which are eliminated upon consolidation at PPL.
(c) PPL's transition services agreement associated with the RIE acquisition ended in the third quarter of 2024. In conjunction with the completion of the agreement, PPL disaggregated the 2024 revenues of the Rhode Island Regulated segment in a manner consistent with that of its other segments. This resulted in certain customer revenues for the Rhode Island Regulated segment, which were previously presented in the "Other" category, being presented in the "Residential", "Commercial" or "Industrial" customer classes beginning on January 1, 2024. Applying the previous methodology to 2024 revenues would result in $469 million of Residential, $372 million of Commercial and $88 million of Industrial for the Rhode Island Regulated segment being presented as "Other" for the year ended December 31, 2024.

As discussed in Note 2, PPL segments its business by geographic location. Revenues from external customers for each segment/geographic location are reconciled to revenues from contracts with customers in the footnotes to the tables above. PPL Electric's revenues from contracts with customers are further disaggregated by distribution and transmission as indicated in the above tables.

Contract receivables from customers are primarily included in "Accounts receivable - Customer" and "Unbilled revenues" on the Balance Sheets.

The following table shows the accounts receivable and unbilled revenues balances that were impaired for the year ended December 31:

	2024	2023	2022
PPL(a)	$ 103	$ 79	$ 70
PPL Electric	52	47	21
LG&E	4	4	6
KU	4	2	6

(a) Includes $23 million for the twelve months ended December 31, 2022 related to the commitment to forgive customer arrearages for low-income and protected residential customers at RIE. See Note 9 for additional information.

The following table shows the balances and certain activity of contract liabilities resulting from contracts with customers:

	PPL	PPL Electric	LG&E	KU
Contract liabilities as of December 31, 2024	$ 39	$ 28	$ 5	$ 6
Contract liabilities as of December 31, 2023	43	29	6	7
Revenue recognized during the year ended December 31, 2024 that was included in the contract liability balance at December 31, 2023	26	12	6	7
Contract liabilities as of December 31, 2023	$ 43	$ 29	$ 6	$ 7
Contract liabilities as of December 31, 2022	34	23	5	6
Revenue recognized during the year ended December 31, 2023 that was included in the contract liability balance at December 31, 2022	21	10	5	6
Contract liabilities as of December 31, 2022	$ 34	$ 23	$ 5	$ 6
Contract liabilities as of December 31, 2021	42	25	6	6
Revenue recognized during the year ended December 31, 2022 that was included in the contract liability balance at December 31, 2021	25	12	6	6

Contract liabilities result from recording contractual billings in advance for customer attachments to the Registrants' infrastructure and payments received in excess of revenues earned to date. Advanced billings for customer attachments are recognized as revenue ratably over the billing period. Payments received in excess of revenues earned to date are recognized as revenue as services are delivered in subsequent periods.

4. Preferred Securities

(PPL)

PPL is authorized to issue up to 10 million shares of preferred stock. No PPL preferred stock was issued or outstanding in 2024, 2023 or 2022.

(PPL Electric)

PPL Electric is authorized to issue up to 20,629,936 shares of preferred stock. No PPL Electric preferred stock was issued or outstanding in 2024, 2023 or 2022.

(LG&E)

LG&E is authorized to issue up to 1,720,000 shares of preferred stock at a $25 par value and 6,750,000 shares of preferred stock without par value. LG&E had no preferred stock issued or outstanding in 2024, 2023 or 2022.

(KU)

KU is authorized to issue up to 5,300,000 shares of preferred stock and 2,000,000 shares of preference stock without par value. KU had no preferred or preference stock issued or outstanding in 2024, 2023 or 2022.

5. Earnings Per Share

(PPL)

Basic EPS is computed by dividing income available to PPL common shareowners by the weighted-average number of common shares outstanding during the applicable period. Diluted EPS is computed by dividing income available to PPL common shareowners by the weighted-average number of common shares outstanding, increased by the number of incremental shares that would be outstanding if potentially dilutive share-based payment awards were converted to common shares as calculated using the Two-Class Method or Treasury Stock Method. Incremental non-participating securities that have a dilutive impact are detailed in the table below.

Reconciliations of the amounts of income and shares of PPL common stock (in thousands) for the periods ended December 31, used in the EPS calculation are:

	2024	2023	2022
Income (Numerator)			
Income from continuing operations after income taxes	$ 888	$ 740	$ 714
Less amounts allocated to participating securities	2	1	1
Income from continuing operations after income taxes available to PPL common shareowners - Basic and Diluted	$ 886	$ 739	$ 713
Income from discontinued operations (net of income taxes) available to PPL common shareowners - Basic and Diluted	$ —	$ —	$ 42
Net income attributable to PPL	$ 888	$ 740	756
Less amounts allocated to participating securities	2	1	1
Net income available to PPL common shareowners - Basic and Diluted	$ 886	$ 739	$ 755
Shares of Common Stock (Denominator)			
Weighted-average shares - Basic EPS	737,756	737,036	736,027
Add: Dilutive share-based payment awards (a)	2,097	1,130	875
Weighted-average shares - Diluted EPS	739,853	738,166	736,902
Basic EPS			
Available to PPL common shareowners:			
Income from continuing operations after income taxes	$ 1.20	$ 1.00	$ 0.97
Income from discontinued operations (net of income taxes)	—	—	0.06
Net Income available to PPL common shareowners	$ 1.20	$ 1.00	$ 1.03
Diluted EPS			
Available to PPL common shareowners:			
Income from continuing operations after income taxes	$ 1.20	$ 1.00	$ 0.96
Income from discontinued operations (net of income taxes)	—	—	0.06
Net Income available to PPL common shareowners	$ 1.20	$ 1.00	$ 1.02

(a) The Treasury Stock Method was applied to non-participating share-based payment awards.

For the years ended December 31, PPL issued common stock related to stock-based compensation plans as follows (in thousands):

	2024	2023
DRIP	202	—

For the years ended December 31, the following shares (in thousands) were excluded from the computations of diluted EPS because the effect would have been antidilutive:

	2024	2023	2022
Stock-based compensation awards	—	243	93

6. Income and Other Taxes

(PPL)

"Income from Continuing Operations Before Income Taxes" is from domestic operations.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for accounting purposes and their basis for income tax purposes and the tax effects of net operating loss and tax credit carryforwards. The provision for PPL's deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles of the applicable jurisdiction. See Notes 1 and 7 for additional information.

Net deferred tax assets have been recognized based on management's estimates of future taxable income.

Significant components of PPL's deferred income tax assets and liabilities were as follows:

	2024	2023
Deferred Tax Assets		
Deferred investment tax credits	28	28
Regulatory liabilities	133	123
Income taxes due to customers	418	436
Accrued pension and postretirement costs	112	101
State loss carryforwards	224	253
Federal and state tax credit carryforwards	24	67
Internal Revenue Code Section 197 intangibles	72	78
Contributions in aid of construction	163	149
Bad debt	37	28
Other	114	111
Valuation allowances	(224)	(245)
Total deferred tax assets	1,101	1,129
Deferred Tax Liabilities		
Plant - net	3,898	3,749
Regulatory assets	432	376
Prepayments	39	47
Goodwill	38	22
Other	38	30
Total deferred tax liabilities	4,445	4,224
Net deferred tax liability	$ 3,344	$ 3,095

State deferred taxes are determined by entity and by jurisdiction. As a result, $12 million and $9 million of net deferred tax assets are shown as "Other noncurrent assets" on the Balance Sheets for 2024 and 2023.

At December 31, 2024, PPL had the following loss and tax credit carryforwards, related deferred tax assets and valuation allowances recorded against the deferred tax assets:

	Gross	Deferred Tax Asset	Valuation Allowance	Expiration
Loss and other carryforwards				
State net operating losses	$ 5,011	$ 224	$ (221)	2025-2044
State charitable contributions	10	1	(1)	2025-2029
Foreign capital loss	8	2	(2)	Indefinite

	Gross	Deferred Tax Asset	Valuation Allowance	Expiration
Credit carryforwards				
Federal - other		14	—	2044
State recycling credit		8	—	2028
State - other		2	—	Indefinite

Valuation allowances have been established for the amount that, more likely than not, will not be realized. The changes in deferred tax valuation allowances were as follows:

		Additions			
	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions	Balance at End of Period
2024	$ 245	$ 3	$ 1	$ 25 (a)	$ 224
2023	213	54 (b)	—	22 (c)	245
2022	462	10	—	259 (d)	213

(a) In 2024, PPL recorded a $23 million decrease in a valuation allowance on a 2004 state net operating loss carryforward that expired in 2024.
(b) PPL has a Pennsylvania net operating loss fully offset by a valuation allowance. In 2023, PPL adjusted the net operating loss and related valuation allowance to be recorded at the current estimate of the applicable rate at which each portion of the net operating loss that will expire and be written off as the rate is reduced annually by one half a percentage point until the rate reaches to 4.99% in 2031.
(c) In 2023, PPL recorded a $22 million decrease in a valuation allowance on a 2003 state net operating loss carryforward that expired in 2023.
(d) In 2022, PPL recorded a $36 million decrease in a valuation allowance on a 2002 state net operating loss carryforward that expired in 2022 and a $213 million decrease in the valuation allowance due to the Pennsylvania rate change. See reconciliation of income tax table below.

Details of the components of income tax expense, a reconciliation of federal income taxes derived from statutory tax rates applied to "Income Before Income Taxes" to income taxes for reporting purposes, and details of "Taxes, other than income" were as follows:

	2024	2023	2022
Income Tax Expense (Benefit)			
Current - Federal (a)	$ 23	$ (175)	$ (2)
Current - State	9	37	24
Total Current Expense (Benefit)	32	(138)	22
Deferred - Federal (a)	137	286	122
Deferred - State	64	48	68
Total Deferred Expense (Benefit), excluding operating loss carryforwards	201	334	190
Amortization of investment tax credit	(3)	(3)	(3)
Tax expense (benefit) of operating loss carryforwards			
Deferred - Federal	1	3	2
Deferred - State	(3)	(12)	(10)
Total Tax Expense (Benefit) of Operating Loss Carryforwards	(2)	(9)	(8)
Total income tax expense (benefit)	$ 228	$ 184	$ 201
Total income tax expense (benefit) - Federal	$ 158	$ 111	$ 119
Total income tax expense (benefit) - State	70	73	82
Total income tax expense (benefit)	$ 228	$ 184	$ 201

(a) In 2023, PPL purchased approximately $300 million of renewable tax credits and recorded a current tax benefit and a deferred tax expense for utilization of approximately $250 million of the credits in 2023 and prior years, per the three-year carry-back rule.

In the table above, the following income tax expense (benefit) are excluded from income taxes:

	2024	2023	2022
Discontinued operations	$ —	$ —	$ (42)
Other comprehensive income	(8)	(14)	11
Valuation allowance recorded to other comprehensive income	—	(1)	—
Total	$ (8)	$ (15)	$ (31)

	2024	2023	2022
Reconciliation of Income Tax Expense (Benefit)			
Federal income tax on Income Before Income Taxes at statutory tax rate - 21%	$ 234	$ 194	$ 192
State income taxes, net of federal income tax benefit	65	58	68
Valuation allowance adjustments (a)	2	12	9
Income tax credits (b)	(8)	(22)	(3)
Utility rate-making tax adjustments (c)	(21)	(10)	(8)
Amortization of excess deferred federal and state income taxes	(45)	(48)	(54)
Other	1	—	(3)
Total increase (decrease)	(6)	(10)	9
Total income tax expense (benefit)	$ 228	$ 184	$ 201
Effective income tax rate	20.4 %	19.9 %	22.0 %

(a) In 2024, 2023, and 2022, PPL recorded deferred income tax expense of $3 million, $11 million and $5 million for valuation allowances primarily related to increased Pennsylvania net operating loss carryforwards expected to be unutilized.
(b) In 2023, PPL purchased approximately $300 million of renewable tax credits and recorded a current tax benefit and a deferred tax expense for utilization of approximately $250 million of the credits in 2023 and prior years, per the three-year carry-back rule.
(c) Primarily consists of tax impacts of AFUDC equity and related depreciation across PPL utilities and flow through tax impacts. Flow through occurs when the regulator excludes deferred tax expense or benefit from recoverable costs when determining income tax expense.

	2024	2023	2022
Taxes, other than income			
State gross earnings and state gross receipts	$ 167	$ 195	$ 175
Property and other	207	197	157
Total	$ 374	$ 392	$ 332

(PPL Electric)

The provision for PPL Electric's deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles reflected in rates established by the PAPUC and the FERC. The difference in the provision for deferred income taxes for regulated assets and liabilities and the amount that otherwise would be recorded under GAAP is deferred and included in "Regulatory assets" or "Regulatory liabilities" on the Balance Sheets.

Significant components of PPL Electric's deferred income tax assets and liabilities were as follows:

	2024	2023
Deferred Tax Assets		
Accrued pension and postretirement costs	$ 36	$ 30
Contributions in aid of construction	120	105
Regulatory liabilities	40	43
Income taxes due to customers	184	191
Other	22	27
Total deferred tax assets	402	396
Deferred Tax Liabilities		
Electric utility plant - net	1,934	1,810
Regulatory assets	160	119
Prepayments	30	36
Other	4	4
Total deferred tax liabilities	2,128	1,969
Net deferred tax liability	$ 1,726	$ 1,573

PPL Electric expects to have adequate levels of taxable income to realize its recorded deferred income tax assets.

Details of the components of income tax expense, a reconciliation of federal income taxes derived from statutory tax rates applied to "Income Before Income Taxes" to income taxes for reporting purposes, and details of "Taxes, other than income" were as follows:

	2024	2023	2022
Income Tax Expense (Benefit)			
Current - Federal	$ 44	$ 91	$ 63
Current - State	4	31	20
Total Current Expense (Benefit)	48	122	83
Deferred - Federal	86	28	60
Deferred - State	42	18	31
Total Deferred Expense (Benefit), excluding operating loss carryforwards	128	46	91
Total income tax expense (benefit)	$ 176	$ 168	$ 174
Total income tax expense (benefit) - Federal	$ 130	$ 119	$ 123
Total income tax expense (benefit) - State	46	49	51
Total income tax expense (benefit)	$ 176	$ 168	$ 174

	2024	2023	2022
Reconciliation of Income Tax Expense (Benefit)			
Federal income tax on Income Before Income Taxes at statutory tax rate - 21%	$ 158	$ 144	$ 147
Increase (decrease) due to:			
State income taxes, net of federal income tax benefit	47	49	54
Utility rate-making tax adjustments (a)	(16)	(9)	(7)
Amortization of excess deferred federal income taxes (b)	(10)	(11)	(12)
State income tax rate change (c)	—	—	(9)
Other	(3)	(5)	1
Total increase (decrease)	18	24	27
Total income tax expense (benefit)	$ 176	$ 168	$ 174
Effective income tax rate	23.5 %	24.5 %	24.9 %

(a) Primarily consists of tax impacts of AFUDC equity and related depreciation across PPL utilities and flow through tax impacts. Flow through occurs when the regulator excludes deferred tax expense or benefit from recoverable costs when determining income tax expense.
(b) In 2024, 2023, and 2022, PPL Electric recorded lower income tax expense for the amortization of excess deferred taxes that primarily resulted from the U.S. federal corporate income tax rate reduction from 35% to 21% enacted by the TCJA. This amortization represents each year's refund amount, prior to a tax gross-up, to be paid to customers for previously collected deferred taxes at higher income tax rates.
(c) 2022 includes a deferred tax benefit of $9 million due to the corporate net income tax rate reduction.

	2024	2023	2022
Taxes, other than income			
State gross receipts	$ 122	$ 136	$ 142
Property and other	9	7	7
Total	$ 131	$ 143	$ 149

(LG&E)

The provision for LG&E's deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles reflected in rates established by the KPSC and the FERC. The difference in the provision for deferred income taxes for regulated assets and liabilities and the amount that otherwise would be recorded under GAAP is deferred and included in "Regulatory assets" or "Regulatory liabilities" on the Balance Sheets.

Significant components of LG&E's deferred income tax assets and liabilities were as follows:

	2024	2023
Deferred Tax Assets		
Contributions in aid of construction	$ 18	$ 18
Regulatory liabilities	18	19
Accrued pension and postretirement costs	4	3
Deferred investment tax credits	7	8
Income taxes due to customers	110	115
State tax credit carryforwards	6	8
Lease liabilities	4	4
Valuation allowances	(6)	(8)
Other	6	8
Total deferred tax assets	167	175
Deferred Tax Liabilities		
Plant - net	875	877
Regulatory assets	88	67
Lease right-of-use assets	4	3
Other	3	4
Total deferred tax liabilities	970	951
Net deferred tax liability	$ 803	$ 776

At December 31, 2024, LG&E had $6 million of state credit carryforwards that expire in 2028 and a $6 million valuation allowance related to state credit carryforwards due to insufficient projected Kentucky taxable income.

Details of the components of income tax expense, a reconciliation of federal income taxes derived from statutory tax rates applied to "Income Before Income Taxes" to income taxes for reporting purposes, and details of "Taxes, other than income" were:

	2024	2023	2022
Income Tax Expense (Benefit)			
Current - Federal	$ 60	$ 70	$ 60
Current - State	11	13	9
Total Current Expense (Benefit)	71	83	69
Deferred - Federal	1	(15)	(10)
Deferred - State	6	2	5
Total Deferred Expense (Benefit)	7	(13)	(5)
Amortization of investment tax credit - Federal	(1)	(1)	(1)
Total income tax expense (benefit)	$ 77	$ 69	$ 63
Total income tax expense (benefit) - Federal	$ 60	$ 54	$ 49
Total income tax expense (benefit) - State	17	15	14
Total income tax expense (benefit)	$ 77	$ 69	$ 63

	2024	2023	2022
Reconciliation of Income Tax Expense (Benefit)			
Federal income tax on Income Before Income Taxes at statutory tax rate - 21%	$ 79	$ 70	$ 70
Increase (decrease) due to:			
State income taxes, net of federal income tax benefit	14	13	13
Amortization of excess deferred federal and state income taxes	(13)	(13)	(18)
Other	(3)	(1)	(2)
Total increase (decrease)	(2)	(1)	(7)
Total income tax expense (benefit)	$ 77	$ 69	$ 63
Effective income tax rate	20.6 %	20.6 %	18.8 %

	2024	2023	2022
Taxes, other than income			
Property and other	$ 49	$ 48	$ 48
Total	$ 49	$ 48	$ 48

(KU)

The provision for KU's deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles reflected in rates established by the KPSC, the VSCC and the FERC. The difference in the provision for deferred income taxes for regulated assets and liabilities and the amount that otherwise would be recorded under GAAP is deferred and included in "Regulatory assets" or "Regulatory liabilities" on the Balance Sheets.

Significant components of KU's deferred income tax assets and liabilities were as follows:

	2024	2023
Deferred Tax Assets		
Contributions in aid of construction	$ 12	$ 10
Regulatory liabilities	29	23
Deferred investment tax credits	20	21
Income taxes due to customers	124	131
State tax credit carryforwards	4	4
Lease liabilities	6	5
Valuation allowances	(2)	(2)
Other	4	5
Total deferred tax assets	197	197
Deferred Tax Liabilities		
Plant - net	1,053	1,045
Regulatory assets	55	50
Pension and postretirement costs	6	7
Lease right-of-use assets	6	5
Other	1	2
Total deferred tax liabilities	1,121	1,109
Net deferred tax liability	$ 924	$ 912

At December 31, 2024, KU had $4 million of state credit carryforwards of which $2 million will expire in 2028 and $2 million that has an indefinite carryforward period. At December 31, 2024, KU had a $2 million valuation allowance related to state credit carryforwards due to insufficient projected Kentucky taxable income.

Details of the components of income tax expense, a reconciliation of federal income taxes derived from statutory tax rates applied to "Income Before Income Taxes" to income taxes for reporting purposes, and details of "Taxes, other than income" were:

	2024	2023	2022
Income Tax Expense (Benefit)			
Current - Federal	$ 87	$ 73	$ 63
Current - State	17	13	11
Total Current Expense (Benefit)	104	86	74
Deferred - Federal	(15)	(11)	(3)
Deferred - State	2	4	7
Total Deferred Expense (Benefit)	(13)	(7)	4
Amortization of investment tax credit - Federal	(2)	(2)	(2)
Total income tax expense (benefit)	$ 89	$ 77	$ 76
Total income tax expense (benefit) - Federal	$ 70	$ 60	$ 58
Total income tax expense (benefit) - State	19	17	18
Total income tax expense (benefit)	$ 89	$ 77	$ 76

	2024	2023	2022
Reconciliation of Income Tax Expense (Benefit)			
Federal income tax on Income Before Income Taxes at statutory tax rate - 21%	$ 93	$ 82	$ 84
Increase (decrease) due to:			
State income taxes, net of federal income tax benefit	16	15	16
Amortization of investment tax credit	(2)	(2)	(2)
Amortization of excess deferred federal and state income taxes	(17)	(17)	(21)
Other	(1)	(1)	(1)
Total decrease	(4)	(5)	(8)
Total income tax expense (benefit)	$ 89	$ 77	$ 76
Effective income tax rate	20.0 %	19.8 %	19.1 %

	2024	2023	2022
Taxes, other than income			
Property and other	$ 49	$ 45	$ 45
Total	$ 49	$ 45	$ 45

(All Registrants)

Unrecognized Tax Benefits

PPL or its subsidiaries file tax returns in four major tax jurisdictions. The income tax provisions for PPL Electric, LG&E and KU are calculated in accordance with an intercompany tax sharing agreement, which provides that taxable income be calculated as if each domestic subsidiary filed a separate consolidated return. PPL Electric or its subsidiaries indirectly or directly file tax returns in three major tax jurisdictions, and LG&E and KU indirectly or directly file tax returns in two major tax jurisdictions. With few exceptions, at December 31, 2024, these jurisdictions, as well as the tax years that are no longer subject to examination, were as follows.

	PPL	PPL Electric	LG&E	KU
U.S. (federal)	2020 and prior	2020 and prior	2020 and prior	2020 and prior
Pennsylvania (state)	2020 and prior	2020 and prior		
Kentucky (state)	2019 and prior	2019 and prior	2019 and prior	2019 and prior

Other

Transfer of Certain Credits under the Inflation Reduction Act (PPL)

The IRS released the final Internal Revenue Code Section 6418 regulations related to the transfer of certain credits under the Inflation Reduction Act. The regulations became effective on July 1, 2024 and did not and are not expected to have a material impact on the financial statements regarding prior or future credit transfers.

IRS Revenue Procedure 2023-15 (PPL and LG&E)

On April 14, 2023, the IRS issued Revenue Procedure 2023-15, which provides a safe harbor method of accounting that taxpayers may use to determine whether expenses to repair, maintain, replace, or improve natural gas transmission and distribution property must be capitalized for tax purposes. PPL and LG&E are currently reviewing the revenue procedure to determine what impact the guidance may have on their financial statements.

Regulatory Treatment of the TCJA (KU)

On November 15, 2018, the FERC issued a policy statement, Docket No. PL19-2-000, requiring companies to disclose the following items related to the accounting and rate treatment of excess and deficient accumulated deferred income taxes (ADIT) in light of the U.S. federal corporate income tax rate change from 35% to 21%, as enacted by the TCJA. The FERC accounts affected include the following:

• Account 190 - Accumulated deferred income taxes
• Account 282 - Accumulated deferred income taxes – other property
• Account 283 - Accumulated deferred income taxes – other
• Account 254 - Other regulatory liabilities
• Account 410.1 - Provision for deferred income taxes
• Account 411.1 - Provision for deferred income taxes - Cr.

Deferred tax assets and liabilities are measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. Thus, at the date of enactment, KU's deferred taxes are remeasured based upon new federal or state corporate income tax rates. The changes in deferred taxes are primarily recorded as an offset to either a regulatory asset or regulatory liability and are reflected in future rates charged to customers. Protected excess ADIT balances are governed by IRS normalization requirements and must be amortized using the Average Rate Assumption Method (ARAM). Unprotected excess ADIT balances are being amortized in accordance with regulatory approvals as discussed below.

For the Kentucky jurisdiction, unprotected excess ADIT balances resulting from the TCJA were amortized over a 15-year period starting January 1, 2018 per final orders in Case Nos. 2018-00034 and 2018-00294. Additionally, in Case No. 2018-00294, KU was approved to use a 15-year amortization period beginning May 1, 2019 for unprotected excess ADIT balances resulting from Kentucky tax reform HB 487. As a result of the most recent Kentucky final order in Case No. 2020-00349, KU amortized the remaining unprotected excess ADIT balances related to the TCJA and HB 487 over a one-year period beginning July 1, 2021, through the economic relief billing credit.

For the Virginia jurisdiction, unprotected excess ADIT balances resulting from the TCJA were amortized over a 5-year period beginning June 1, 2018 per the final order in Case No. PUR-2017-00106.

For the FERC Jurisdiction, KU made a compliance filing on April 1, 2020 to address Order No. 864, Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes. In this filing, KU established a 15-year amortization period for unprotected excess ADIT in FERC Transmission formula rates. KU plans to address the amortization of unprotected excess ADIT for generation formula rates in future rate filings.

The table below shows the related amounts associated with the reversal and elimination of ADIT balances; the amount of excess and deficient ADIT that is protected and unprotected; the accounts to which the excess or deficient ADIT will be amortized; and the amortization period of the excess and deficient ADIT to be returned or recovered through rates for both protected and unprotected ADIT. Additionally, a reconciliation to Form 1 page 278 – Other Regulatory Liabilities is provided.

	Unamortized Net Excess ADIT as of 12/31/23 (a)	2024 Amortization of Excess ADIT (b)	Unamortized Net Excess ADIT as of 12/31/24
Plant Related (c):			
Account 282 - Property Related	$ 401,819,109	$ 16,873,910	$ 384,945,199
Account 282 - Coal Combustion Residual AROs	2,242,127	305,534	1,936,593
Account 190 - Net Operating Losses	(8,466,084)	(352,787)	(8,113,297)
Plant Related (c):	$ 395,595,152	$ 16,826,657	$ 378,768,495
Unprotected Non Plant Related:			
Account 190 - Other Temporary Differences	$ (562,532)	$ —	$ (562,532)
Account 282 - Other Temporary Differences	99,644	—	99,644
Account 283 - Other Temporary Differences	598,513	—	598,513
Total Unprotected Non Plant Related	$ 135,625	$ —	$ 135,625
Total Excess Deferred Tax	$ 395,730,777	$ 16,826,657	$ 378,904,120
Tax Gross-up Factor			1.33245
Excess Deferred Tax Regulatory Liability			$ 504,868,914
Regulatory Liability on Unamortized Investment Tax Credits (ITC)			$ 27,047,659
Total Tax Regulatory Liability			$ 531,916,573
ASC 740 Regulatory Liability - FERC Form 1 page 278			531,916,573
Difference			—

(a) Excess ADIT balances resulting from U.S. federal (TCJA) and Kentucky (HB 487) corporate income tax rate reductions effective January 1, 2018, U.S. federal corporate income tax rate reduction in 1986, and Kentucky corporate income tax rate reductions in 2005 through 2007.
(b) Excess ADIT balances are recorded to account 254 and reversed through accounts 410.1/411.1. See discussion above for amortization periods used for protected and unprotected excess ADIT.
(c) Plant related excess ADIT balances are currently treated as "protected" by the company and amortized using ARAM.

7. Utility Rate Regulation

Regulatory Assets and Liabilities

(All Registrants)

PPL, PPL Electric, LG&E and KU reflect the effects of regulatory actions in the financial statements for their rate-regulated utility operations. Regulatory assets and liabilities are classified as current if, upon initial recognition, the entire amount related to an item will be recovered or refunded within a year of the balance sheet date.

(PPL)

RIE is subject to the jurisdiction of the RIPUC, the Rhode Island Division of Public Utilities and Carriers, and the FERC. RIE operates under a FERC-approved open access transmission tariff. RIE's base distribution rates are calculated based on recovery of costs as well as a return on rate base. Certain other recovery mechanisms exist to recover expenses and capital investments with a return on rate base separate from the base distribution rate case process.

(PPL, LG&E and KU)

LG&E is subject to the jurisdiction of the KPSC and the FERC, and KU is subject to the jurisdiction of the KPSC, the VSCC and the FERC.

LG&E's and KU's Kentucky base rates are calculated based on recovery of costs as well as a return on capitalization (common equity, long-term debt and short-term debt) including adjustments for certain net investments and costs recovered separately through other means. As such, LG&E and KU generally earn a return on regulatory assets.

(PPL and KU)

KU's Virginia base rates are calculated based on recovery of costs as well as a return on rate base (net utility plant plus working capital less accumulated deferred income taxes and miscellaneous deductions). As all regulatory assets and liabilities, except for regulatory assets and liabilities related to the levelized fuel factor, accumulated deferred income taxes, pension and postretirement benefits, and AROs related to certain CCR impoundments, are excluded from the return on rate base utilized in the calculation of Virginia base rates, no return is earned on the related assets.

KU's rates to municipal customers for wholesale power requirements are calculated based on annual updates to a formula rate that utilizes a return on rate base (net utility plant plus working capital less accumulated deferred income taxes and miscellaneous deductions). As all regulatory assets and liabilities, except accumulated deferred income taxes, are excluded from the return on rate base utilized in the development of municipal rates, no return is earned on the related assets.

(PPL and PPL Electric)

PPL Electric is subject to the jurisdiction of the PAPUC and the FERC. PPL Electric's distribution base rates are calculated based on recovery of costs as well as a return on distribution rate base (net utility plant plus a working capital allowance less plant-related deferred taxes and other miscellaneous additions and deductions). PPL Electric's transmission revenues are billed in accordance with a FERC tariff that allows for recovery of transmission costs incurred, a return on transmission-related rate base (net utility plant plus a working capital allowance less plant-related deferred taxes and other miscellaneous additions and deductions) and an automatic annual update. See "Transmission Formula Rate" below for additional information on this tariff. All regulatory assets and liabilities are excluded from distribution and transmission return on investment calculations; therefore, generally no return is earned on PPL Electric's regulatory assets.
(All Registrants)

The following table provides information about the regulatory assets and liabilities of cost-based rate-regulated utility operations at December 31:

	PPL		PPL Electric		LG&E			KU	
	2024	2023	2024	2023	2024	2023		2024	2023
Current Regulatory Assets:									
Rate adjustment mechanism	$ 95	$ 118	$ —	$ —	$ —	$ —		$ —	$ —
Renewable energy certificates	14	14	—	—	—	—		—	—
Derivative instruments	3	51	—	—	—	—		—	—
Smart meter rider	7	6	7	6	—	—		—	—
Storm damage expense rider	68	12	68	12	—	—		—	—
Transmission service charge	44	43	27	31	—	—		—	—
Transmission formula rate	14	5	2	—	—	—		—	—
ISR deferral	22	11	—	—	—	—		—	—
Gas line tracker	4	—	—	—	4	—		—	—
TCJA customer refund and recovery	21	—	21	—	—	—		—	—
DSIC	8	7	8	7	—	—		—	—
Other	20	26	—	1	4	7		1	3
Total current regulatory assets	$ 320	$ 293	$ 133	$ 57	$ 8	$ 7	$ 7	$ 1	$ 3
Noncurrent Regulatory Assets:									
Defined benefit plans	$ 967	$ 887	$ 473	$ 417	$ 226	$ 217		$ 149	$ 136
Plant outage cost	30	38	—	—	7	10		23	28
Net metering	147	112	—	—	—	—		—	—
Environmental cost recovery	96	99	—	—	—	—		—	—
Storm costs	113	97	22	—	20	15		29	14
Unamortized loss on debt	20	22	3	3	9	10		6	7
Interest rate swaps	4	7	—	—	4	7		—	—
Terminated interest rate swaps	53	58	—	—	31	34		22	24
Accumulated cost of removal of utility plant	173	178	173	178	—	—		—	—
AROs	280	289	—	—	75	76		205	213
Retired asset recovery	83	—	—	—	83	—		—	—
Derivative instruments	1	8	—	—	—	—		—	—
Gas line inspections	24	21	—	—	22	19		2	2
Advanced metering infrastructure	28	15	—	—	14	7		14	8
Other	41	43	2	—	—	—		8	7
Total noncurrent regulatory assets	$ 2,060	$ 1,874	$ 673	$ 598	$ 491	$ 395		$ 458	$ 439

	PPL		PPL Electric		LG&E		KU	
	2024	2023	2024	2023	2024	2023	2024	2023
Current Regulatory Liabilities:								
Generation supply charge	$ 52	$ 51	$ 52	$ 51	$ —	$ —	$ —	$ —
TCJA customer refund and recovery	—	5	—	5	—	—	—	—
Act 129 compliance rider	2	15	2	15	—	—	—	—
Transmission formula rate	1	21	—	18	—	—	—	—
Rate adjustment mechanism	71	72	—	—	—	—	—	—
Energy efficiency	25	23	—	—	—	—	—	—
Gas supply clause	—	15	—	—	—	15	—	—
DSM	17	1	—	—	7	—	10	1
Environmental cost recovery	12	—	—	—	6	—	6	—
Other	43	22	3	2	1	1	6	—
Total current regulatory liabilities	$ 223	$ 225	$ 57	$ 91	$ 14	$ 16	$ 22	$ 1
Noncurrent Regulatory Liabilities:								
Accumulated cost of removal of utility plant	$ 1,022	$ 996	$ —	$ —	$ 314	$ 306	$ 408	$ 399
Power purchase agreement - OVEC	10	19	—	—	7	13	3	6
Net deferred taxes	1,899	1,977	739	763	439	459	498	523
Defined benefit plans	294	252	100	73	24	20	65	59
Terminated interest rate swaps	54	57	—	—	27	29	27	28
Energy efficiency	16	5	—	—	—	—	—	—
Other	40	34	—	—	4	—	8	3
Total noncurrent regulatory liabilities	$ 3,335	$ 3,340	$ 839	$ 836	$ 815	$ 827	$ 1,009	$ 1,018

Following is an overview of selected regulatory assets and liabilities detailed in the preceding tables. Specific developments with respect to certain of these regulatory assets and liabilities are discussed in "Regulatory Matters."

Defined Benefit Plans

(All Registrants)

Defined benefit plan regulatory assets and liabilities represent prior service cost and net actuarial gains and losses that will be recovered in defined benefit plans expense through future base rates based upon established regulatory practices and, generally, are amortized over the average remaining service lives of plan participants. These regulatory assets and liabilities are adjusted at least annually or whenever the funded status of defined benefit plans is remeasured.

(PPL, LG&E and KU)

As a result of previous rate case settlements and orders, the difference between pension cost calculated in accordance with LG&E's and KU's pension accounting policy and pension cost calculated using a 15-year amortization period for actuarial gains and losses and settlements are recorded as a regulatory asset. As of December 31, 2024, the balances were $79 million for PPL, $44 million for LG&E and $35 million for KU. As of December 31, 2023, the balances were $86 million for PPL, $46 million for LG&E and $40 million for KU.

(PPL)

RIE is subject to a pension rate adjustment mechanism whereby the difference in amounts allowed to be recovered in rates versus actual costs of RIE's pension and other postretirement benefit plans that are to be recovered from or passed back to customers in future periods, are also recorded as regulatory assets and liabilities.

(All Registrants)

Storm Costs

PPL Electric, LG&E and KU have the ability to request from the PAPUC, the KPSC and the VSCC, as applicable, the authority to treat expenses related to specific extraordinary storms as a regulatory asset and defer such costs for regulatory accounting and reporting purposes. Once such authority is granted, LG&E and KU can request recovery of those expenses in a base rate case and begin amortizing the costs when recovery starts. PPL Electric can recover qualifying expenses caused by major storm events, as defined in its retail tariff, over three years through the Storm Damage Expense Rider commencing in the application year after the storm occurred. LG&E's and KU's regulatory assets for storm costs approved for base rate recovery are being amortized through various dates ending in 2031.

As provided in the Amended Settlement Agreement (ASA), RIE has the authority from the RIPUC to treat certain incremental O&M expenses related to specific extraordinary storms as a regulatory asset and defer such costs for regulatory accounting and reporting purposes. Once all expenses for the extraordinary storm have been finalized, RIE files a final accounting of those storm expenses with the RIPUC that is subject to review by the RIPUC and the Rhode Island Division of Public Utilities and Carriers.

Unamortized Loss on Debt

Unamortized loss on reacquired debt represents losses on long-term debt refinanced, reacquired or redeemed that have been deferred and will be amortized and recovered over either the original life of the extinguished debt or the life of the replacement debt (in the case of refinancing). Such costs are being amortized through 2053 for PPL Electric, through 2042 for KU, and through 2044 for LG&E.

Accumulated Cost of Removal of Utility Plant

RIE, LG&E and KU charge costs of removal through depreciation expense with an offsetting credit to a regulatory liability. The regulatory liability is relieved as costs are incurred.

PPL Electric does not accrue for costs of removal. When costs of removal are incurred, PPL Electric records the costs as a regulatory asset. Such deferral is included in rates and amortized over the subsequent five-year period.

Net Deferred Taxes

Regulatory liabilities associated with net deferred taxes represent the future revenue impact from the adjustment of deferred income taxes required primarily for excess deferred taxes and unamortized investment tax credits, largely a result of the TCJA.

(PPL and PPL Electric)

Distribution System Improvement Charge (DSIC)

The DSIC is authorized under Act 11 and is considered an alternative ratemaking mechanism providing more timely cost recovery of qualifying distribution system capital improvements. DSIC is charged to all customers taking distribution service as a percentage of total distribution revenue (excluding State Tax Adjustment Surcharge). DSIC is capped at 5% of the total amount billed to all customers for distribution service (including reconcilable riders) which provides a safeguard for customers. PPL Electric is permitted to utilize the DSIC mechanism so long as the rolling 12-month ROE for the applicable period does not exceed the PAPUC ROE in the company's PAPUC quarterly financial report filing. The DSIC contains a reconciliation mechanism whereby any over- or under-recovery from customers is either refunded to, or recovered from, customers through the adjustment factor determined for the subsequent year.

Generation Supply Charge (GSC)

The GSC is a cost recovery mechanism that permits PPL Electric to recover costs incurred to provide generation supply to PLR customers who receive basic generation supply service. The recovery includes charges for generation supply, as well as administration of the acquisition process. In addition, the GSC contains a reconciliation mechanism whereby any over- or under-recovery from prior periods is refunded to, or recovered from, customers through the adjustment factor determined for the subsequent rate filing period.

Transmission Service Charge (TSC)

PPL Electric is charged by PJM for transmission service-related costs applicable to its PLR customers. PPL Electric passes these costs on to customers, who receive basic generation supply service through the PAPUC-approved TSC cost recovery mechanism. The TSC contains a reconciliation mechanism whereby any over- or under-recovery from customers is either refunded to, or recovered from, customers through the adjustment factor determined for the subsequent year.

RIE arranges transmission service on behalf of its customers and bills the costs of those services to customers, pursuant to its Transmission Service Cost Adjustment Provision. The TSC contains a reconciliation mechanism whereby any over- or under-recovery from customers is either refunded to, or recovered from, customers through the adjustment factor determined for the subsequent year.

Transmission Formula Rate

PPL Electric's transmission revenues are billed in accordance with a FERC-approved Open Access Transmission Tariff that utilizes a formula-based rate recovery mechanism. Under this formula, beginning in 2023, rates are put into effect on January 1st of each year based upon actual expenditures from the most recently filed FERC Form 1, forecasted capital additions, and other data based on PPL Electric's books and records. 2023 was considered a transitional period as the calendar year rate approved by FERC became effective April 1, 2023. Rates are compared during the year to the estimated annual expenses and capital additions that will be filed in PPL Electric's annual FERC Form 1, filed under the FERC's Uniform System of Accounts. Under the mechanism, any difference between the revenue requirement in effect and actual expenditures incurred for that year is recorded as a regulatory asset or regulatory liability, and the regulatory asset or regulatory liability is to be recovered from or returned to customers starting one year after the conclusion of the rate year.

Storm Damage Expense Rider (SDER)

The SDER is a reconcilable automatic adjustment clause under which PPL Electric annually will compare actual storm costs to storm costs allowed in base rates and refund or recover any differences from customers. In the 2015 rate case settlement approved by the PAPUC in November 2015, it was determined that reportable storm damage expenses to be recovered annually through base rates will be set at $20 million. The SDER will recover from or refund to customers the applicable expenses from reportable storms as compared to the $20 million recovered annually through base rates.

Act 129 Compliance Rider

In compliance with Pennsylvania's Act 129 of 2008 and implementing regulations, PPL Electric is currently in Phase IV of the energy efficiency and conservation plan which was approved in March 2021. Phase IV allows PPL Electric to recover the maximum $313 million over the five-year period, June 1, 2021 through May 31, 2026. The plan includes programs intended to reduce electricity consumption. The recoverable costs include direct and indirect charges, including design and development costs, general and administrative costs and applicable state evaluator costs. The rates are applied to customers who receive distribution service through the Act 129 Compliance Rider. The actual Phase IV program costs are reconcilable after each 12-month period, and any over- or under-recovery from customers will be refunded or recovered over the next rate filing period.

Smart Meter Rider (SMR)

Act 129 requires each electric distribution company (EDC) with more than 100,000 customers to have a PAPUC approved Smart Meter Technology Procurement and Installation Plan (SMP). As of December 31, 2019, PPL Electric replaced substantially all of its old meters with meters that meet the Act 129 requirements under its SMP. In accordance with Act 129, EDCs are able to recover the costs and earn a return on capital of providing smart metering technology. PPL Electric uses the SMR to recover the costs to implement its SMP. The SMR is a reconciliation mechanism whereby any over- or under-recovery from prior years is refunded to, or recovered from, customers through the adjustment factor determined for the subsequent quarters.

Universal Service Rider (USR)

The USR provides for recovery of costs associated with universal service programs, OnTrack and Winter Relief Assistance Program (WRAP), provided by PPL Electric to residential customers. OnTrack is a special payment program for low-income households and WRAP provides low-income customers a means to reduce electric bills through energy saving methods. The USR rate is applied to residential customers who receive distribution service. The actual program costs are reconcilable, and any over- or under-recovery from customers will be refunded or recovered annually in the subsequent year.

TCJA Customer Refund and Recovery

As a result of the reduced U.S federal corporate income tax rate as enacted by the TCJA, the PAPUC ruled that these tax benefits should be refunded to customers. Timing differences between the recognition of these tax benefits and the refund of the benefit to the customer creates a regulatory liability. PPL Electric's liability is being credited back to distribution customers through a temporary negative surcharge and remains in place until PPL Electric files and the PAPUC approves new base rates. The TCJA is reconcilable, and any over- or under-recovery from customers will be refunded or recovered annually in the subsequent year.

(PPL, LG&E and KU)

Fuel Adjustment Clauses

LG&E's and KU's retail electric rates contain a fuel adjustment clause, whereby variances in power purchases and the cost of fuel to generate electricity, including transportation costs, from the costs embedded in base rates are adjusted in LG&E's and KU's rates. The KPSC requires formal reviews at six-month intervals to examine past fuel adjustments and at two-year intervals to review past operations of the fuel adjustment clause and, to the extent appropriate, may conduct public hearings and reestablish the fuel charge included in base rates. The regulatory assets or liabilities represent the amounts that have been under- or over-recovered due to timing or adjustments to the mechanism and are typically recovered within 12 months.

KU also employs a levelized fuel factor mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs and load for the fuel year (12 months ending March 31). The Virginia levelized fuel factor allows fuel recovery based on projected fuel costs for the fuel year plus an adjustment for any under- or over-recovery of fuel expenses from the prior fuel year. The regulatory assets or liabilities represent the amounts that have been under- or over-recovered due to timing or adjustments to the mechanism and are typically recovered or refunded within 12 months.

AROs

As discussed in Note 1, for LG&E and KU, all ARO accretion and depreciation expenses are reclassified as a regulatory asset or regulatory liability. ARO regulatory assets associated with certain CCR projects are amortized to expense in accordance with regulatory approvals. For other AROs, deferred accretion and depreciation expense is recovered through cost of removal.

Power Purchase Agreement - OVEC

As a result of purchase accounting associated with PPL's acquisition of LG&E and KU, the fair values of the OVEC power purchase agreement were recorded on the balance sheets of LG&E and KU with offsets to regulatory liabilities. The regulatory liabilities are being amortized using the units-of-production method until March 2026, the expiration date of the agreement at the date of the acquisition. LG&E's and KU's customer rates continue to reflect the original contracts. See Notes 12 and 17 for additional discussion of the power purchase agreement.

Interest Rate Swaps

LG&E's unrealized gains and losses are recorded as regulatory assets or regulatory liabilities until they are realized as interest expense. Interest expense from existing swaps is realized and recovered over the terms of the associated debt, which matures in 2033.

<u>Terminated Interest Rate Swaps</u>

Net realized gains and losses on all interest rate swaps are recovered through regulated rates. As such, any gains and losses on these derivatives are included in regulatory assets or liabilities and are primarily recognized in "Interest Expense" on the Statements of Income over the life of the associated debt.

<u>Plant Outage Costs</u>

From July 1, 2017 through June 30, 2021, plant outage costs were normalized for ratemaking purposes based on an average level of expenses. Plant outage expenses that were greater or less than the average will be collected from or returned to customers, through future base rates. Effective July 1, 2021, under-recovered plant outage costs are being amortized through 2029 for LG&E and KU.

<u>Advanced Metering Infrastructure</u>

In 2021 orders from the KPSC, LG&E and KU received approval to record regulatory assets comprised of the operating expenses associated with implementation of the AMI project and the incremental difference between AFUDC accrued at LG&E's and KU's weighted average cost of capital and that calculated using the methodology approved by the FERC. Recovery of these costs will be determined in the base rate case proceeding following the completion of the AMI implementation project.

(PPL)

<u>Derivative Instruments</u>

Derivative instruments that qualify for recovery from, or refund to, customers through future rates are recorded at fair value, with changes in fair value recorded as regulatory assets or regulatory liabilities in the period in which the change occurs. The balance is reconcilable, and any over- or under-recovery from customers will be refunded or recovered annually in the subsequent year.

<u>Energy Efficiency</u>

The energy efficiency mechanism is designed to collect the estimated costs of RIE's energy efficiency plan for the upcoming calendar year. Any differences between revenue billed to customers through RIE's energy efficiency charge and the costs of RIE's energy efficiency programs, as approved by the RIPUC, are recorded as regulatory assets or regulatory liabilities. The final annual over or under collection is reconciled in the next year's energy efficiency plan filing, as part of the reconciliation factor calculation. RIE may file to change the energy efficiency plan charge at any time should significant over-or under-recoveries occur.

<u>Net Metering</u>

The net metering mechanism provides for recovery of costs associated with customer-installed on-site generation facilities, including the costs of renewable generation credits. Net metering is reconcilable annually, and any over- or under-recovery from customers will be refunded to, or recovered from, customers through the adjustment factor determined for the subsequent year.

<u>Rate Adjustment Mechanisms</u>

In addition to commodity costs, RIE is subject to a number of additional rate adjustment mechanisms whereby a regulatory asset or regulatory liability is recognized resulting from differences between actual revenues and the underlying cost being recovered or differences between actual revenues and targeted amounts as approved by the RIPUC. The rate adjustment mechanisms are reconcilable, and any over- or under-recovery from customers are to be refunded or recovered annually in the subsequent year.

<u>Renewable Energy Certificates</u>

The Renewable Energy Certificates regulatory asset represents deferred costs associated with RIE's compliance obligation with the Rhode Island Renewable Portfolio Standard (RPS). The RPS is legislation established to foster the development of new renewable energy sources. The regulatory asset will be recovered over the next year.

<u>Taxes Recoverable through Future Rates</u>

Taxes recoverable through future rates represent the portion of future income taxes that are anticipated to be recovered through future rates based upon established regulatory practices. Accordingly, this regulatory asset is recognized when the offsetting deferred tax liability is recognized. For general-purpose financial reporting, this regulatory asset and the deferred tax liability are not offset; rather, each is displayed separately. This regulatory asset is expected to be recovered over the period that the underlying book-tax timing differences reverse and the actual cash taxes are incurred.

(PPL, LG&E and KU)

<u>Environmental Cost Recovery</u>

Kentucky law permits LG&E and KU to recover the costs, including a return of operating expenses and a return of and on capital invested, of complying with the Clean Air Act and those federal, state or local environmental requirements, which apply to coal combustion wastes and by-products from coal-fired electricity generating facilities. The KPSC requires reviews of the past operations of the environmental surcharge for six-month and two-year billing periods to evaluate the related charges, credits and rates of return, as well as to provide for the roll-in of ECR amounts to base rates each two-year period. The KPSC has authorized return on equity of 9.35% for existing approved ECR projects. The ECR regulatory asset or liability represents the amount that has been under- or over-recovered due to timing or adjustments to the mechanism and is typically recovered or refunded within 12 months.
RIE's rate plans provide for specific rate allowances for RIE's share of the estimated costs to investigate and perform certain remediation activities at sites with which it may be associated, with variances deferred for future recovery from, or return to, customers. RIE believes future costs, beyond the expiration of current rate plans, will continue to be recovered through rates. The regulatory asset represents the excess of amounts incurred for RIE's actual site investigation and remediation costs versus amounts received in rates.

(PPL and LG&E)

<u>Gas Supply Clause</u>

LG&E's natural gas rates contain a gas supply clause, whereby the expected cost of natural gas supply and variances between actual and expected costs and customer usage from prior periods are adjusted quarterly in LG&E's rates, subject to approval by the KPSC. The gas supply clause previously included a separate natural gas procurement incentive mechanism, which allowed LG&E's rates to be adjusted annually to share savings between the actual cost of gas purchases and market indices, with the shareholders and the customers during each performance-based rate year (12 months ending October 31). The operation of this incentive mechanism expired on October 31, 2024, but savings achieved through October 31, 2024 will be included in LG&E's rates through October 31, 2026. The regulatory assets or liabilities represent the total amounts that have been under- or over-recovered due to timing or adjustments to the mechanisms and are typically recovered or refunded within 18 months.

<u>Retired Asset Recovery (RAR) Rider</u>

The RAR rider was established by KPSC orders in 2021 to provide recovery of and return on the remaining investment in certain electric generating units, including the remaining net book value of each unit, materials and supplies that cannot be used at other plants and any associated removal costs, upon their retirement over a ten-year period following retirement. Costs included as of December 31, 2024 represent the remaining net book value and materials and supplies that cannot be used as a result of the retirement of Mill Creek Unit 1. The associated removal costs will be added to the RAR rider regulatory asset or regulatory liability as costs are incurred.

Regulatory Matters

<u>Rhode Island Activities</u> *(PPL)*

Advanced Metering Functionality (AMF)

In 2021, RIE filed its Updated AMF Business Case and Grid Modernization Plan (GMP) with the RIPUC in accordance with the Amended Settlement Agreement (ASA) approved by the RIPUC in August 2018, and which among other things, sought approval to deploy smart meters throughout the service territory. After PPL completed the acquisition of RIE, RIE filed a new AMF Business Case with the RIPUC in 2022, consisting of a detailed proposal for full-scale deployment of AMF across its electric service territory.

On September 27, 2023, the RIPUC unanimously approved RIE to deploy an AMF-based metering system for the electric distribution business. RIE is authorized to seek recovery of the approved capital investment through the ISR process with an overall multi-year cap on recovery at approximately $153 million, subject to certain terms, conditions and limitations with respect to the potential offsets and recoverability of certain costs. RIE is required to continue spending even if above the recovery cap, until it achieves the functionalities outlined in the AMF Business Case. RIE filed with the RIPUC for approval of (i) an updated electric Service Quality Plan on December 27, 2023, (ii) additional compliance tariff provisions regarding recovery and updated cost schedules to reflect the RIPUC's decision on December 22, 2023, and (iii) electric and gas tariff advice filings for RIPUC Automatic Meter Reading/AMF meter opt-out tariff provision on September 19, 2024. The RIPUC approved RIE's revised service quality metrics with certain modifications on August 1, 2024 and October 30, 2024. In addition, the RIPUC approved RIE's AMR/AMF opt-out tariff provisions for electric and natural gas with modifications on December 19, 2024 for effect January 1, 2025, and approved the proposed updated fees to be assessed at the start of the AMF roll-out. On January 7, 2025, RIE filed compliance tariffs to reflect the RIPUC's ruling, which they approved at their January 23, 2025 Open Meeting.

Grid Modernization Plan (GMP)

RIE filed a new GMP with the RIPUC on December 30, 2022. The new GMP filing consists of a holistic suite of grid modernization investments that will provide RIE with the tools and capability to manage the electric distribution system more granularly considering a range of distributed energy resources adoption levels, accelerated by Rhode Island's climate mandates, while at the same time maintaining a safe and reliable electric distribution system. The GMP is an informational guidance document that supports the grid modernization investments to be proposed in future electric ISR plans. Consequently, RIE did not request approval from the RIPUC for any specific investments or seek cost recovery as part of the GMP; rather, RIE requested the RIPUC issues an order affirming RIE's compliance with its obligation to file a GMP that meets the requirements of the ASA. At an Open Meeting on November 21, 2024, the RIPUC unanimously ruled that RIE satisfied the requirement to file a GMP. This decision does not represent a ruling on the GMP and the docket will remain open, though RIE does not expect further action on this docket.

FY 2025 Gas ISR Plan

On December 22, 2023, RIE filed its FY 2025 Gas ISR Plan with the RIPUC with a budget that includes $185 million of capital investment spend plus up to an additional $11 million of contingency plan spending in connection with the PHMSA's potential enactment of regulations during FY 2025 that, if enacted would significantly alter RIE's leak detection and repair obligations under federal regulations. RIE also filed its proposed gas ISR plan budgetary and reconciliation framework, addressing issues raised in connection with its FY submission, with its FY 2025 ISR Plan. The RIPUC held hearings in March 2024, and on March 26, 2024, approved, the plan, including the proposed budgetary and reconciliation framework, with a total approved FY 2025 Gas ISR Plan of $180 million of which $168 million is for capital investment spend and $12 million spend for paving costs as operations and maintenance (O&M), plus the potential additional $11 million available if the above-mentioned regulations are implemented by the PHMSA. On March 28, 2024, the RIPUC approved RIE's compliance filing for rates effective April 1, 2024.

FY 2026 Gas ISR Plan

On December 31, 2024, RIE filed its FY 2026 Gas ISR Plan with the RIPUC with a budget that includes $187 million of capital investment spend and up to $15 million of additional contingency plan spend in connection with the PHMSA's potential enactment of regulations during FY 2026 that, if enacted, would significantly alter RIE's leak detection and repair obligations under federal regulations. The Plan also includes proposed spending on curb-to-curb paving of $22 million. A decision from the RIPUC on the Plan is expected by March 31, 2025. RIE cannot predict the outcome of this matter.

FY 2025 Electric ISR Plan

On December 21, 2023, RIE filed its FY 2025 Electric ISR Plan with the RIPUC with a budget that includes $141 million of capital investment spend, $13 million of vegetation management O&M spend and $1 million of Other O&M spend. RIE also filed its proposed electric ISR plan budgetary and reconciliation framework addressing issues raised in connection with its FY 2024 submission, with its FY 2025 ISR Plan. The RIPUC held hearings in March 2024, and on March 26, 2024, approved the plan, including the proposed budgetary and reconciliation framework, with modifications to the proposed capital investment spend, resulting in a total approved FY 2025 Electric ISR Plan of $132 million for capital investment spend, $13 million for vegetation management O&M spend, and $1 million for Other O&M spend. On March 28, 2024, the RIPUC approved RIE's compliance filing for rates effective April 1, 2024.

FY 2026 Electric ISR Plan

On December 23, 2024, RIE filed its FY 2026 Electric ISR Plan with the RIPUC with a budget that includes $160 million of capital investment spend, $14 million of vegetation O&M spend and $1 million of Other O&M spend. In addition, the FY 2026 Electric ISR Plan includes $88 million of capital investment spend for Advanced Metering Functionality (AMF) which, together with the $160 million of capital investment spend, results in total capital investment spend of $248 million. A decision from the RIPUC is expected by March 31, 2025. RIE cannot predict the outcome of this matter.

Kentucky Activities *(PPL, LG&E and KU)*

Kentucky January 2025 Storm

In January 2025, LG&E and KU experienced snow, ice, sleet and freezing rain in their service territories, resulting in substantial damage to certain of LG&E's and KU's assets. On January 31, 2025, LG&E and KU submitted a filing with the KPSC requesting regulatory asset treatment of the extraordinary operations and maintenance expenses portion of the costs incurred related to the storm. These are estimated to be $2 million for LG&E and $8 million for KU. LG&E and KU cannot predict the outcome of this matter.

Kentucky September 2024 Storm

In September 2024, LG&E and KU experienced significant winds and rain activity in their service territories, resulting in substantial damage to certain of LG&E's and KU's assets. On October 15, 2024, LG&E and KU submitted a filing with the KPSC requesting regulatory asset treatment of the extraordinary operations and maintenance expenses portion of the costs incurred related to the storm. On December 4, 2024, the KPSC issued an order approving LG&E's and KU's request for regulatory asset accounting treatment, with recovery amounts and amortization thereof to be determined in subsequent base rate proceedings. LG&E and KU cannot predict the outcome of this matter. As of December 31, 2024, LG&E and KU recorded regulatory assets related to the storm of $1 million and $5 million.

Kentucky May 2024 Storm

In May 2024, LG&E and KU experienced significant windstorm activity in their service territories, resulting in substantial damage to certain of LG&E's and KU's assets. On June 13, 2024, LG&E and KU submitted a filing with the KPSC requesting regulatory asset treatment of the extraordinary operations and maintenance expenses portion of the costs incurred related to the storm. On July 2, 2024, the KPSC issued an order provisionally approving the request for accounting purposes, noting that the decision on approval of recovery would be determined in the future. On November 21, 2024, the KPSC issued an order confirming the approval of LG&E's and KU's request for regulatory asset accounting treatment, with recovery amounts and amortization thereof to be determined in subsequent base rate proceedings. LG&E and KU cannot predict the outcome of this matter. As of December 31, 2024, LG&E and KU each recorded regulatory assets related to the storm of $4 million.

KPSC Investigation Related to Winter Storm Elliott

On December 22, 2023, the KPSC initiated an investigation into the practices of LG&E and KU regarding the provision of electric service from December 23, 2022 through December 25, 2022, during a period of extreme temperatures during Winter Storm Elliott. The investigation was the result of LG&E's and KU's need to implement brief service interruptions to approximately 55,000 customers during this period. The purpose of the investigation was to supplement discovery and examination already completed through LG&E's and KU's CPCN proceedings, a legislative hearing completed in February 2023 and reports completed by the NERC and the FERC related to the issue. Additionally, the investigation was to evaluate LG&E's and KU's actions taken, or planned to be taken, since Winter Storm Elliott that affect their ability to provide service during periods of variable weather and power system stress. LG&E and KU believe actions taken during the period under question were necessary and appropriate. A hearing on the matter occurred on May 23, 2024. On January 7, 2025, the KPSC issued an Order finding that LG&E and KU did not willfully violate a regulation, statute or KPSC Order associated with the Winter Storm Elliot event. The case is now closed and removed from the KPSC's docket.

Mill Creek Unit 1 and Unit 2 Retired Asset Recovery (RAR) (PPL and LG&E)

In November 2023, the KPSC issued an order approving, among other items, the requested retirement of Mill Creek Units 1 and 2.

On October 4, 2024, LG&E submitted an application related to the retirement of Mill Creek Unit 1, which occurred on December 31, 2024, requesting recovery of associated costs under the RAR rider. LG&E expects these costs to be approximately $125 million and proposes to begin application of the RAR rider with bills issued in May 2025. On October 28, 2024, the KPSC issued an order to establish a procedural schedule regarding its investigation of the reasonableness of the proposed tariff. The KPSC intends to rule on the matter by February 28, 2025. LG&E cannot predict the outcome of this proceeding.

Mill Creek Unit 2 is expected to be retired in 2027. LG&E anticipates the recovery of associated costs, including the remaining net book value, for Mill Creek Unit 2 through the RAR rider. The remaining net book value of Mill Creek Unit 2 was approximately $221 million at December 31, 2024 and LG&E is continuing to depreciate using the current approved rates through its retirement date in 2027. LG&E expects to reclassify the net book value remaining at retirement, which is expected to total approximately $161 million, to a regulatory asset to be amortized over a period of ten years in accordance with the RAR.

Pennsylvania Activities *(PPL and PPL Electric)*

PAPUC investigation into billing issues

On January 31, 2023, the PAPUC initiated an investigation focused on billing issues related to estimated, irregular bills and customer service concerns following customer complaints, which for many customers were driven by increased prices for electricity supply. Certain bills issued during the time period of December 20, 2022 through January 9, 2023 were estimated due to a technical issue that prevented PPL Electric from providing actual collected meter data to customer facing and other internal systems. Customers also reported difficulties accessing PPL Electric's website and contacting the customer service call center. The PAPUC's Bureau of Investigation & Enforcement (I&E) has directed PPL Electric to respond to certain inquiries and document requests. PPL Electric submitted its responses to the information request and cooperated fully with the investigation. PPL Electric reached a Settlement Agreement with I&E on November 21, 2023. In the settlement, PPL Electric agreed to pay a civil penalty of $1 million, make certain remedial improvements to its billing systems and processes, and agreed to not seek recovery for extraordinary costs incurred in responding to or resulting from the billing event. On November 21, 2023, PPL Electric and I&E submitted a Joint Petition for Approval of Settlement to the PAPUC. On January 18, 2024, the PAPUC issued an Order requesting public comment prior to the PAPUC entering a Final Order on the petition. Comments were due on February 28, 2024, and comments were filed by the Office of Consumer Advocate, CAUSE-PA (low-income advocate), and individual customers. On March 19, 2024, PPL Electric filed reply comments. On April 25, 2024, the PAPUC announced at its public meeting that it would be issuing an order approving the Settlement Agreement with modifications. The modifications included converting the $1 million civil penalty to a $1 million donation to PPL Electric's hardship fund, Operation HELP, and requiring PPL Electric to make various progress reports on efforts to remediate the billing issue. PPL Electric and I&E had 20 business days from the issuance of the PAPUC order to accept or reject the proposed modifications to the Settlement Agreement. The time period to withdraw from the Settlement Agreement expired on June 14, 2024, without PPL Electric or I&E withdrawing from the Settlement Agreement, and the terms of the Settlement Agreement, as modified by the PAPUC's order, are now final. PPL Electric is in the process of complying with the terms of the Settlement Agreement, and made the required contribution to Operation HELP on June 24, 2024.

PPL Electric incurred expenses, primarily related to billing write-offs, of $18 million and $34 million for the years ended December 31, 2024 and 2023 related to the billing issue. PPL Electric will not seek regulatory recovery of these costs.

DSIC Petition

On April 26, 2024, PPL Electric filed a Petition with the PAPUC requesting that the PAPUC waive PPL Electric's DSIC cap of 5% of billed revenues and increase the maximum allowable DSIC to 9% for bills rendered on or after January 1, 2025. On November 21, 2024, the Administrative Law Judge in the proceeding issued a Recommended Decision recommending the denial of PPL Electric's DSIC Cap Waiver Petition. PPL Electric filed exceptions to the Recommended Decision on December 11, 2024. Several of the other parties filed Reply Exceptions on December 23, 2024. The Administrative Law Judge's Recommended Decision and the Exceptions and Reply Exceptions are currently before the PAPUC for a final order. PPL Electric cannot predict the timing or outcome of that decision.

Act 129

The Pennsylvania Public Utility Code requires EDCs to meet, by specified dates, specified goals for reduction in customer electricity usage and peak demand. EDCs not meeting the requirements of Act 129 are subject to significant penalties. PPL Electric filed with the PAPUC its Act 129 Phase IV Energy Efficiency and Conservation Plan on November 30, 2020, for the five-year period starting June 1, 2021 and ending on May 31, 2026. PPL Electric's Phase IV Act 129 Plan was approved by the PAPUC at its March 25, 2021, public meeting.

The Pennsylvania Public Utility Code also requires EDCs to act as a default service provider (DSP), which provides electricity generation supply service to customers pursuant to a PAPUC-approved default service procurement plan. A DSP is able to recover the costs associated with its default service procurement plan.

In March 2024, PPL Electric filed a Petition for Approval of a new default service program and procurement plan with the PAPUC for the period June 1, 2025 through May 31, 2029. In August 2024, PPL Electric submitted a Joint Petition for Settlement in the proceeding. In September 2024, the Administrative Law Judge issued an Interim Order approving the proposed settlement without modification. The PAPUC adopted the Interim Order on November 7, 2024, without modification which finalized the settlement.

Federal Matters

FERC Transmission Rate Filing (PPL, LG&E and KU)

In 2018, LG&E and KU applied to the FERC requesting elimination of certain on-going waivers and credits to a sub-set of transmission customers relating to the 1998 merger of LG&E's and KU's parent entities and the 2006 withdrawal of LG&E and KU from the Midcontinent Independent System Operator, Inc. (MISO), a regional transmission operator and energy market. The application sought termination of LG&E's and KU's commitment to provide certain Kentucky municipalities mitigation for certain horizontal market power concerns arising out of the 1998 LG&E and KU merger and 2006 MISO withdrawal. The amounts at issue are generally waivers or credits granted to a limited number of Kentucky municipalities for either certain LG&E and KU or MISO transmission charges incurred for transmission service received. In 2019, the FERC granted LG&E's and KU's request to remove the ongoing credits, conditioned upon the implementation by LG&E and KU of a transition mechanism for certain existing power supply arrangements, which was subsequently filed, modified, and approved by the FERC in 2020 and 2021. In 2020, LG&E and KU and other parties filed appeals with the U.S. Court of Appeals - D.C. Circuit (D.C. Circuit Court of Appeals) regarding the FERC's orders on the elimination of the mitigation and required transition mechanism. In August 2022, the D.C. Circuit Court of Appeals issued an order remanding the proceedings back to the FERC. On May 18, 2023, the FERC issued an order on remand reversing its 2019 decision and requiring LG&E and KU to refund credits previously withheld, including under such transition mechanism. LG&E and KU filed a petition for review of the FERC's May 18, 2023 order with the D.C. Circuit Court of Appeals and provided refunds in accordance with the FERC order on December 1, 2023. The FERC issued an order on LG&E's and KU's compliance filing on November 16, 2023, and LG&E and KU filed a petition for review of this November 16, 2023 order on February 14, 2024. The FERC issued the substantive order on rehearing on March 21, 2024, reaffirming its prior decision. Oral argument before the D.C. Circuit Court of Appeals occurred on January 21, 2025. LG&E and KU cannot predict the ultimate outcome of the proceedings or any other post decision process but do not expect the annual impact to have a material effect on their operations or financial condition. LG&E and KU currently receive recovery of certain waivers and credits primarily through base rates increases, provided, however, that increases associated with the FERC's May 18, 2023 order are expected to be subject to future rate proceedings.

Recovery of Transmission Costs (PPL)

Until December 2022, RIE's transmission facilities were operated in combination with the transmission facilities of National Grid's New England affiliates, Massachusetts Electric Company (MECO) and New England Power (NEP), as a single integrated system with NEP designated as the combined operator. As of January 1, 2023, RIE operates its own transmission facilities. ISO-NE allocates RIE's costs among transmission customers in New England, in accordance with the ISO Open Access Transmission Tariff (ISO-NE OATT). According to the FERC orders, RIE is compensated for its actual monthly transmission costs, with its authorized maximum Return on Equity (ROE) of 11.74% on its transmission assets.

The ROE for transmission rates under the ISO-NE OATT is the subject of four complaints that are pending before the FERC. On October 16, 2014, the FERC issued an order on the first complaint, Opinion No. 531-A, resetting the base ROE applicable to transmission assets under the ISO-NE OATT from 11.14% to 10.57% effective as of October 16, 2014 and establishing a maximum ROE of 11.74%. On April 14, 2017, this order was vacated and remanded by the D. C. Circuit Court of Appeals (Court of Appeals). After the remand, the FERC issued an order on October 16, 2018 applicable to all four pending cases where it proposed a new base ROE methodology that, with subsequent input and support from the New England Transmission Owners (NETO), yielded a base ROE of 10.41%. Subsequent to the FERC's October 2018 order in the New England Transmission Owners cases, the FERC further refined its ROE methodology in another proceeding and has applied that refined methodology to transmission owners' ROEs in other jurisdictions, and the NETOs filed further information in the New England matters to distinguish their case. Those determinations in other jurisdictions have recently been vacated and remanded back to the FERC for further proceedings by the D.C. Circuit Court of Appeals. The proceeding and the final base rate ROE determination in the New England matters remain open, pending a final order from the FERC. PPL cannot predict the outcome of this matter, and an estimate of the impact cannot be determined.

Other

Purchase of Receivables Program

(PPL and PPL Electric)

In accordance with a PAPUC-approved purchase of accounts receivable program, PPL Electric purchases certain accounts receivable from alternative electricity suppliers at a discount, which reflects a provision for uncollectible accounts. The alternative electricity suppliers have no continuing involvement or interest in the purchased accounts receivable. Accounts receivable that are acquired are initially recorded at fair value on the date of acquisition. During 2024, 2023 and 2022, PPL Electric purchased $1.5 billion, $1.5 billion and $1.3 billion of accounts receivable from alternative suppliers.

(PPL)

In 2021 and 2022, the RIPUC approved various components of a Purchase of Receivables Program (POR) in Rhode Island for effect on April 1, 2022. Municipal aggregators and non-regulated power producers (collectively, Competitive Suppliers) are eligible to participate in accordance with RIE's approved electric tariffs for municipal aggregation and non-regulated power producers. Under the POR program, RIE will purchase the Competitive Suppliers' accounts receivables, including existing receivables, at discounted rates, regardless of whether RIE has collected the owed monies from customers. The program is intended to make RIE whole through the implementation of a discount rate or Standard Complete Bill Percentage (SCBP) paid by Competitive Suppliers. RIE calculates the SCBP for each customer class and files the calculations with the RIPUC for review and approval by February 15 of each year. At an Open Meeting on March 26, 2024, the RIPUC approved the SCBP for effect beginning on April 1, 2024, for a one-year period.

8. Financing Activities

Credit Arrangements and Short-term Debt

(All Registrants)

The Registrants maintain credit facilities to enhance liquidity, provide credit support and provide a backstop to commercial paper programs. For reporting purposes, on a consolidated basis, the credit facilities and commercial paper programs of PPL Electric, LG&E and KU also apply to PPL. The amounts listed in the borrowed column below are recorded as "Short-term debt" on the Balance Sheets. The following credit facilities were in place at:

	Expiration Date	December 31, 2024 Capacity	Borrowed	Letters of Credit and Commercial Paper Issued (d)	Unused Capacity	December 31, 2023 Borrowed	Letters of Credit and Commercial Paper Issued (d)
PPL							
PPL Capital Funding							
Syndicated Credit Facility (a) (b) (c)	Dec 2028	$ 1,250	$ —	$ 138	$ 1,112	$ —	$ 390
Bilateral Credit Facility (a) (b)	Feb 2025	100	—	—	100	—	—
Bilateral Credit Facility (a) (b)	Feb 2025	100	—	15	85	—	13
Total PPL Capital Funding Credit Facilities		$ 1,450	$ —	$ 153	$ 1,297	$ —	$ 403
PPL Electric							
Syndicated Credit Facility (a) (b)	Dec 2028	650	—	1	649	—	511
Total PPL Electric Credit Facilities		$ 650	$ —	$ 1	$ 649	$ —	$ 511
LG&E							
Syndicated Credit Facility (a) (b)	Dec 2028	500	—	25	475	—	—
Total LG&E Credit Facilities		$ 500	$ —	$ 25	$ 475	$ —	$ —
KU							
Syndicated Credit Facility (a) (b)	Dec 2028	400	—	140	260	—	93
Total KU Credit Facilities		$ 400	$ —	$ 140	$ 260	$ —	$ 93

(a) Each company pays customary fees under its respective facility and borrowings generally bear interest at applicable secured overnight financing rates or base rates, plus an applicable margin.
(b) The facilities contain a financial covenant requiring debt to total capitalization not to exceed 70% for PPL Capital Funding, RIE, PPL Electric, LG&E and KU, as calculated in accordance with the facilities and other customary covenants. Additionally, subject to certain conditions, PPL Capital Funding may request that the capacity of one of its bilateral credit facilities expiring in February 2025 be increased by up to $30 million and that the capacity of its syndicated credit facility be increased by up to $400 million. PPL Electric, LG&E and KU may each request up to a $250 million increase in its syndicated credit facility's capacity, subject to regulatory approval of the increased capacity. Participation in any such increase is at the sole discretion of each lender.
(c) Includes a $250 million borrowing sublimit for RIE and a $1 billion sublimit for PPL Capital Funding at December 31, 2024 and 2023. At December 31, 2024, PPL Capital Funding had $138 million of commercial paper outstanding and RIE had no commercial paper outstanding. At December 31, 2023, PPL Capital Funding had $365 million of commercial paper outstanding and RIE had $25 million of commercial paper outstanding. RIE's obligations under the facility are not guaranteed by PPL.
(d) Commercial paper issued reflects the undiscounted face value of the issuance.

(PPL)

In January 2025, PPL Capital Funding amended and restated its existing $1.25 billion syndicated credit facility to extend the termination date from December 6, 2028 to December 6, 2029 and to increase the borrowing capacity under the facility to $1.5 billion.

(PPL and PPL Electric)

In January 2025, PPL Electric amended and restated its existing $650 million syndicated credit facility to extend the termination date from December 6, 2028 to December 6, 2029 and to increase the borrowing capacity under the facility to $750 million.

(PPL and LG&E)

In January 2025, LG&E amended and restated its existing $500 million syndicated credit facility to extend the termination date from December 6, 2028 to December 6, 2029 and to increase the borrowing capacity under the facility to $600 million.

(PPL and KU)

In January 2025, KU amended and restated its existing $400 million syndicated credit facility to extend the termination date from December 6, 2028 to December 6, 2029 and to increase the borrowing capacity under the facility to $600 million.

(All Registrants)

The Registrants maintain commercial paper programs to provide an additional financing source to fund short-term liquidity needs. Commercial paper issuances, included in "Short-term debt" on the Balance Sheets, are supported by the respective Registrant's credit facilities. The following commercial paper programs were in place at:

	December 31, 2024 Weighted - Average Interest Rate	Capacity	Commercial Paper Issuances (c)	Unused Capacity	December 31, 2023 Weighted - Average Interest Rate	Commercial Paper Issuances (c)
PPL Capital Funding (a)	4.76%	$ 1,350	$ 138	$ 1,212	5.66%	$ 365
RIE (b)		250	—	250	5.72%	25
PPL Electric		650	—	650	5.67%	510
LG&E	4.72%	500	25	475		—
KU	4.71%	400	140	260	5.64%	93
Total		$ 3,150	$ 303	$ 2,847		$ 993

(a) PPL Capital Funding's obligations are fully and unconditionally guaranteed by PPL.
(b) Issuances under the PPL Capital Funding and RIE commercial paper programs are supported by the PPL Capital Funding syndicated credit facility, which, at December 31, 2024, had a total capacity of $1.25 billion and under which they are both borrowers. PPL Capital Funding's Commercial paper program is also backed by a separate bilateral credit facility for $100 million. The PPL Capital Funding syndicated credit facility includes a borrowing sublimit for RIE, which at December 31, 2024 was set at $250 million with the remaining $1 billion allocated to PPL Capital Funding. RIE's obligations under the facility are not guaranteed by PPL. The sublimits of each borrower may be decreased or increased at the borrowers' option up to a prescribed amount such that all borrowings under the syndicated credit facility cannot exceed the size of the credit facility of $1.25 billion.
(c) Commercial paper issued reflects the undiscounted face value of the issuance.

(PPL Electric, LG&E and KU)

See Note 13 for a discussion of intercompany borrowings.

Long-term Debt *(All Registrants)*

	Weighted-Average Rate (d)	Maturities (d)	December 31, 2024	December 31, 2023
PPL				
Senior Unsecured Notes	4.34 %	2026 - 2047	$ 4,316	$ 3,066
Senior Secured Notes/First Mortgage Bonds (a) (b) (c)	4.38 %	2025 - 2053	10,878	10,229
Exchangeable Senior Unsecured Notes	2.88 %	2028	1,000	1,000
Junior Subordinated Notes	7.25 %	2067	480	480
Total Long-term Debt before adjustments			16,674	14,775
Unamortized premium and (discount), net			(57)	(55)
Unamortized debt issuance costs			(114)	(108)
Total Long-term Debt			16,503	14,612
Less current portion of Long-term Debt			551	1
Total Long-term Debt, noncurrent			$ 15,952	$ 14,611
PPL Electric				
Senior Secured Notes/First Mortgage Bonds (a) (b)	4.64 %	2027 - 2053	$ 5,299	$ 4,649
Total Long-term Debt Before Adjustments			5,299	4,649
Unamortized discount			(42)	(42)
Unamortized debt issuance costs			(43)	(40)
Total Long-term Debt			5,214	4,567
Less current portion of Long-term Debt			—	—
Total Long-term Debt, noncurrent			$ 5,214	$ 4,567
LG&E				
Senior Secured Notes/First Mortgage Bonds (a) (c)	4.01 %	2025 - 2049	$ 2,489	$ 2,489
Total Long-term Debt Before Adjustments			2,489	2,489
Unamortized discount			(4)	(4)
Unamortized debt issuance costs			(14)	(16)
Total Long-term Debt			2,471	2,469
Less current portion of Long-term Debt			300	—
Total Long-term Debt, noncurrent			$ 2,171	$ 2,469
KU				
Senior Secured Notes/First Mortgage Bonds (a) (c)	4.22 %	2025 - 2050	$ 3,089	$ 3,089
Total Long-term Debt Before Adjustments			3,089	3,089
Unamortized premium			4	5
Unamortized discount			(8)	(9)
Unamortized debt issuance costs			(19)	(21)
Total Long-term Debt			3,066	3,064
Less current portion of Long-term Debt			250	—
Total Long-term Debt, noncurrent			$ 2,816	$ 3,064

(a) Includes PPL Electric's senior secured and first mortgage bonds that are secured by the lien of PPL Electric's 2001 Mortgage Indenture, which covers substantially all of PPL Electric's tangible distribution properties and certain of its tangible transmission properties located in Pennsylvania, subject to certain exceptions and exclusions. The carrying value of PPL Electric's property, plant and equipment was approximately $13.3 billion and $12.4 billion at December 31, 2024 and 2023.

Includes LG&E's first mortgage bonds that are secured by the lien of the LG&E 2010 Mortgage Indenture which creates a lien, subject to certain exceptions and exclusions, on substantially all of LG&E's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity and the storage and distribution of natural gas. The aggregate carrying value of the property subject to the lien was $6.0 billion and $5.9 billion at December 31, 2024 and 2023.

Includes KU's first mortgage bonds that are secured by the lien of the KU 2010 Mortgage Indenture which creates a lien, subject to certain exceptions and exclusions, on substantially all of KU's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity. The aggregate carrying value of the property subject to the lien was $7.5 billion and $7.3 billion at December 31, 2024 and 2023.

(b) Includes PPL Electric's series of senior secured bonds that secure its obligations to make payments with respect to each series of Pollution Control Bonds that were issued by the LCIDA on behalf of PPL Electric. These senior secured bonds were issued in the same principal amount, contain payment and redemption provisions that correspond to and bear the same interest rate as such Pollution Control Bonds. These senior secured bonds were issued under PPL Electric's 2001 Mortgage Indenture and are secured as noted in (a) above. The tax-exempt revenue bonds are subject to mandatory redemption upon determination that the interest rate on the bonds would be included in the holders' gross income for federal tax purposes.

(c) Includes LG&E's and KU's series of first mortgage bonds that were issued to the respective trustees of tax-exempt revenue bonds to secure its respective obligations to make payments with respect to each series of bonds. The first mortgage bonds were issued in the same principal amounts, contain payment and redemption provisions that correspond to and bear the same interest rate as such tax-exempt revenue bonds. These first mortgage bonds were issued under the LG&E 2010 Mortgage Indenture and the KU 2010 Mortgage Indenture and are secured as noted in (a) above. The related tax-exempt revenue bonds were issued by various governmental entities, principally counties in Kentucky, on behalf of LG&E and KU. The related revenue bond documents allow LG&E and KU to convert the interest rate mode on the bonds from time to time to a commercial paper rate, daily rate, weekly rate, term rate of at least one year or, in some cases, an auction rate or a SOFR index rate. At December 31, 2024, the aggregate tax-exempt revenue bonds issued on behalf of LG&E and KU that were in a term rate mode totaled $894 million for PPL, comprised of $538 million and $356 million for LG&E and KU. At December 31, 2024, the aggregate tax-exempt revenue bonds issued on behalf of LG&E and KU that were in a variable rate mode totaled $66 million and $33 million for LG&E and KU. These variable rate tax-exempt revenue bonds are subject to tender for purchase by LG&E and KU at the option of the holder and to mandatory tender for purchase by LG&E and KU upon the occurrence of certain events.

(d) The table reflects principal maturities only, based on stated maturities, sinking fund requirements, or earlier put dates, and the weighted-average rates as of December 31, 2024.

The aggregate maturities of long-term debt, based on sinking fund requirements, stated maturities or earlier put dates, for the periods 2025 through 2029 and thereafter are as follows:

	PPL	PPL Electric	LG&E	KU
2025	$ 551	$ —	$ 300	$ 250
2026	904	—	90	164
2027	428	108	260	60
2028	1,350	—	—	—
2029	116	116	—	—
Thereafter	13,325	5,075	1,839	2,615
Total	$ 16,674	$ 5,299	$ 2,489	$ 3,089

(PPL)

In March 2024, RIE issued $500 million of 5.35% Senior Notes due 2034. RIE received proceeds of $496 million, net of discounts and underwriting fees, to be used to repay short-term debt and for other general corporate purposes.

In August 2024, PPL Capital Funding issued $750 million of 5.25% Senior Notes due 2034. PPL Capital Funding received proceeds of $741 million, net of discounts and underwriting fees, to be used to repay short-term debt and for other general corporate purposes.

(PPL and PPL Electric)

In January 2024, PPL Electric issued $650 million of 4.85% First Mortgage Bonds due 2034. PPL Electric received proceeds of $644 million, net of discounts and underwriting fees, to be used to repay short-term debt and for other general corporate purposes.

(PPL Electric, LG&E and KU)

See Note 13 for additional information related to intercompany borrowings.

Legal Separateness *(All Registrants)*

The subsidiaries of PPL are separate legal entities. PPL's subsidiaries are not liable for the debts of PPL. Accordingly, creditors of PPL may not satisfy their debts from the assets of PPL's subsidiaries absent a specific contractual undertaking by a subsidiary to pay PPL's creditors or as required by applicable law or regulation. Similarly, other than PPL's guarantee of PPL Capital Funding's obligations, PPL is not liable for the debts of its subsidiaries, nor are its subsidiaries liable for the debts of one another. Accordingly, creditors of PPL's subsidiaries may not satisfy their debts from the assets of PPL or its other subsidiaries absent a specific contractual undertaking by PPL or its other subsidiaries to pay the creditors or as required by applicable law or regulation.

Similarly, the subsidiaries of PPL Electric are each separate legal entities. These subsidiaries are not liable for the debts of PPL Electric. Accordingly, creditors of PPL Electric may not satisfy its debts from the assets of its subsidiaries absent a specific contractual undertaking by a subsidiary to pay the creditors or as required by applicable law or regulation. Similarly, PPL Electric is not liable for the debts of its subsidiaries, nor are its subsidiaries liable for the debts of one another. Accordingly, creditors of these subsidiaries may not satisfy their debts from the assets of PPL Electric (or its other subsidiaries) absent a specific contractual undertaking by PPL Electric or any such other subsidiary to pay such creditors or as required by applicable law or regulation.

(PPL)

Distributions and Related Restrictions

In November 2024, PPL declared its quarterly common stock dividend, payable January 2, 2025, at 25.75 cents per share (equivalent to $1.03 per annum). On February 13, 2025, PPL announced a quarterly common stock dividend of 27.25 cents per share, payable April 1, 2025, to shareowners of record as of March 10, 2025. Future dividends will be declared at the discretion of the Board of Directors and will depend upon future earnings, cash flows, financial and legal requirements and other factors.

Neither PPL Capital Funding nor PPL may declare or pay any cash dividend or distribution on its capital stock during any period in which PPL Capital Funding defers interest payments on its 2007 Series A Junior Subordinated Notes due 2067. At December 31, 2024, no interest payments were deferred.

(All Registrants)

PPL relies on dividends or loans from its subsidiaries to fund PPL's dividends to its common shareholders. The net assets of certain PPL subsidiaries are subject to legal restrictions. LG&E, KU, PPL Electric and RIE are subject to Section 305(a) of the Federal Power Act, which makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in capital account." The meaning of this limitation has never been clarified under the Federal Power Act. LG&E, KU, PPL Electric and RIE believe, however, that this statutory restriction, as applied to their circumstances, would not be construed or applied by the FERC to prohibit the payment from retained earnings of dividends that are not excessive and are for lawful and legitimate business purposes. In February 2012, LG&E and KU petitioned the FERC requesting authorization to pay dividends in the future based on retained earnings balances calculated without giving effect to the impact of purchase accounting adjustments for PPL's 2010 acquisition of LG&E and KU. In May 2012, the FERC approved the petitions with the further condition that each utility may not pay dividends if such payment would cause its adjusted equity ratio to fall below 30% of total capitalization. Accordingly, at December 31, 2024, net assets of $1.5 billion for LG&E and $2.0 billion for KU were restricted for purposes of paying dividends to LKE, and net assets of $1.8 billion for LG&E and $2.3 billion for KU were available for payment of dividends to LKE. LG&E and KU believe they will not be required to change their current dividend practices as a result of the foregoing requirement. In addition, under Virginia law, KU is prohibited from making loans to affiliates without the prior approval of the VSCC. There are no comparable statutes under Kentucky law applicable to LG&E and KU, or under Pennsylvania law applicable to PPL Electric. However, orders from the KPSC require LG&E and KU to obtain prior consent or approval before lending amounts to PPL.

9. Acquisitions, Development and Divestitures

(PPL)

Acquisitions

Acquisition of Narragansett Electric

On May 25, 2022, PPL Rhode Island Holdings acquired 100% of the outstanding shares of common stock of Narragansett Electric from National Grid U.S., a subsidiary of National Grid plc (the Acquisition). Narragansett Electric, whose service area covers substantially all of Rhode Island, is primarily engaged in the transmission and distribution of electricity and distribution of natural gas. The Acquisition expands PPL's portfolio of regulated natural gas and electricity transmission and distribution assets, has improved PPL's credit metrics and is expected to enhance long term earnings growth. Following the closing of the Acquisition, Narragansett Electric provides services doing business under the name Rhode Island Energy (RIE).

The consideration for the Acquisition consisted of approximately $3.8 billion in cash and approximately $1.5 billion of long-term debt assumed through the transaction. The fair value of the consideration paid for Narragansett Electric was as follows (in billions):

Aggregate enterprise consideration	$ 5.3
Less: fair value of assumed long-term debt outstanding	1.5
Total cash consideration	$ 3.8

The $3.8 billion total cash consideration paid was funded with proceeds from PPL's 2021 sale of its U.K. utility business.

In connection with the Acquisition, National Grid USA Service Company, Inc., National Grid U.S. and Narragansett Electric entered into a transition services agreement (TSA), pursuant to which the National Grid entities agreed to provide certain transition services to Narragansett Electric to facilitate the transition of the operation of Narragansett Electric to PPL following the Acquisition, as agreed upon in the Narragansett share purchase agreement. The TSA was for an initial two-year term and was completed in the third quarter of 2024. TSA costs of $137 million, $228 million, and $123 million were incurred for the years ended December 31, 2024, 2023, and 2022.

Commitments to the Rhode Island Division of Public Utilities and Carriers and the Attorney General of the State of Rhode Island

As a condition to the Acquisition, PPL made certain commitments to the Rhode Island Division of Public Utilities and Carriers and the Attorney General of the State of Rhode Island. As a result:

- RIE provided a credit to all its electric and natural gas distribution customers in the total amount of $50 million ($40 million net of tax benefit). Based on the relative number of electric distribution customers and natural gas distribution customers as of November 1, 2022, RIE refunded, in the form of a bill credit, $33 million to electric customers and $17 million to natural gas customers of amounts collected from customers since the Acquisition date. Each electric customer received the same credit, and each natural gas customer received the same credit. A reduction of revenue and a regulatory liability of $50 million for the amounts refunded were recorded during the quarter ended September 30, 2022. These credits were issued during the fourth quarter of 2022. The amounts refunded did not impact RIE's earnings sharing regulatory mechanism.
- RIE forgave approximately $44 million ($21 million net of allowance for doubtful accounts) in arrearages for low-income and protected residential customers, which represents 100% of the arrearages over 90 days for those customers as of March 31, 2022. PPL deemed these accounts uncollectible and fully reserved for them as of September 30, 2022, resulting in an increase to "Other operations and maintenance expense" on the Statement of Income of $23 million for the year ended December 31, 2022.

- RIE will not file a base rate case seeking an increase in base distribution rates for natural gas and/or electric service sooner than three years from the Acquisition date, and RIE will not submit a request for a change in base rates unless and until there is at least twelve months of operating experience under PPL's exclusive leadership and after the TSA with National Grid terminates.
- RIE will forgo potential recovery of any and all transition costs, which includes (1) the installation of certain information technology systems; (2) modification and enhancements to physical facilities in Rhode Island; and (3) incurring costs related to severance payments, communications and branding changes, and other transition related costs. These costs, which are being expensed as incurred, were $307 million, $262 million, and $181 million for the years ended December 31, 2024, 2023, and 2022.
- RIE will not seek to recover any transaction costs related to the Acquisition, which were $28 million through December 31, 2024, including an immaterial amount for the years ended December 31, 2024 and 2023, and $18 million for the year ended December 31, 2022. These amounts were recorded in "Other operations and maintenance" on the Statement of Income.
- RIE will not seek to recover in rates any markup charged by National Grid U.S. and/or its affiliates under the TSA which were $10 million, $7 million, and $3 million for the years ended December 31, 2024, 2023, and 2022.
- In June 2022, RIE expensed $20 million of regulatory assets as of the Acquisition date for the Gas Business Enablement (GBE) project and for certain Cybersecurity/IT investments related to GBE. The expense was recorded to "Other operations and maintenance" on the Statements of Income for the year ended December 31, 2022. RIE will not seek to recover these regulatory assets from customers in any future proceedings.
- RIE will exclude all goodwill from the ratemaking capital structure.
- RIE will hold harmless Rhode Island customers from any changes to Accumulated Deferred Income Taxes (ADIT) as a result of the Acquisition. RIE reserves the right to seek rate adjustments based on future changes to ADIT that are not related to the Acquisition.
- RIE will not increase its revenue requirement to a level higher than what would exist in the absence of the Acquisition as a result of any restatement of pension and other post-retirement benefits plan assets and liabilities to fair value after the close of the Acquisition.
- Rhode Island Holdings contributed $2.5 million to the Rhode Island Commerce Corporation's Renewable Energy Fund and will not use any of the $2.5 million to meet its pre-existing renewable energy credit goals in Rhode Island or any other state. This contribution was made during the year ended December 31, 2022 and was recorded in "Other Income (Expense)" on the Statement of Income.
- RIE will make available up to $2.5 million for the Rhode Island Attorney General to utilize as needed in evaluating PPL's report on RIE's specific decarbonization goals to support Rhode Island's 2021 Act on Climate or to assess the future of the gas distribution business in Rhode Island. This amount was accrued during the year ended December 31, 2022 and was recorded in "Other Income (Expense) - net" on the Statement of Income.
- Various other operational and reporting commitments have been established.

Purchase Price Allocation

The operations of Narragansett Electric are subject to the accounting for certain types of regulation as prescribed by GAAP. The carrying value of Narragansett Electric's assets and liabilities subject to rate-setting and cost recovery provisions provide revenues derived from costs, including a return on investment of net assets and liabilities included in rate base. Therefore, the fair values of these assets and liabilities equal their carrying values. Accordingly, neither the assets acquired nor liabilities assumed reflect any adjustments related to these amounts.

Total goodwill resulting from the acquisition was $1,585 million. PPL has elected to not reflect the effects of purchase accounting in the separate financial statements of RIE or PPL's Rhode Island Regulated segment. Accordingly, the Rhode Island Regulated segment includes $725 million of acquired legacy goodwill. The remaining excess purchase price of $860 million is included in PPL's Corporate and Other category for segment reporting purposes. The goodwill reflects the value paid for the expected continued growth of a rate-regulated business located in a defined service area with a constructive regulatory environment, the ability of PPL to leverage its assembled workforce to take advantage of those growth opportunities
and the attractiveness of stable, growing cash flows. The tax goodwill is deductible for income tax purposes over a 15 year period, and as such, deferred taxes will be recorded as the tax deductions are taken.

The table below shows the allocation of the purchase price to the assets acquired and liabilities assumed that were recorded in PPL's Consolidated Balance Sheet as of the Acquisition date. The allocation was subject to change during the one-year measurement period as additional information was obtained about the facts and circumstances that existed at closing. Adjustments to certain assets acquired and liabilities assumed during the year ended December 31, 2023 resulted in a decrease in goodwill of $1 million since the purchase price allocation as of December 31, 2022.

	Final Purchase Price Allocation
Assets	
Current Assets	
Cash and Cash Equivalents	$ 154
Accounts Receivable (a)	195
Unbilled Revenues	54
Price Risk Management Assets	99
Regulatory Assets	75
Other Current Assets	65
Total Current Assets	**642**
Noncurrent Assets	
Property, Plant and Equipment, net	3,992
Regulatory Assets	393
Goodwill	1,585
Other Noncurrent Assets	164
Total Noncurrent Assets	**6,134**
Total Assets	**$ 6,776**
Liabilities	
Current Liabilities	
Long-Term Debt Due Within One Year	$ 14
Accounts Payable	180
Taxes Accrued	44
Regulatory Liabilities	239
Other Current Liabilities	198
Total Current Liabilities	**675**
Noncurrent Liabilities	
Long-Term Debt	1,496
Regulatory Liabilities	643
Other Deferred Credits and Noncurrent Liabilities	142
Noncurrent Liabilities	**2,281**
Total Purchase Price (Balance Sheet Net Assets)	**$ 3,820**

(a) Amounts represent fair value as of May 25, 2022. The gross contractual amount is $255 million. Cash flows not expected to be collected as of May 25, 2022 were $60 million.

Pro Forma Financial Information

The actual RIE Operating Revenues and Net income attributable to PPL included in PPL's Statement of Income for the period ended December 31, 2022, and PPL's unaudited pro forma 2022 Operating Revenues and Net Income (Loss) attributable to PPL, including RIE, as if the Acquisition had occurred prior to January 1, 2022 are as follows.

	Operating Revenues	Net Income (Loss)
Actual RIE results included from May 25, 2022 - December 31, 2022 (a)	$ 1,038	$ (44)
PPL Pro Forma for the year ended 2022	8,667	790

(a) Net Income (Loss) includes expenses of $98 million (pre-tax) related to commitments made as a condition of the Acquisition.

The pro forma financial information presented above has been derived from the historical consolidated financial statements of PPL and Narragansett Electric. Non-recurring items included in the 2022 pro forma financial information include: (a) $18 million (pre-tax) of transaction costs related to the Acquisition, primarily for advisory, accounting and legal fees incurred, (b) $223 million (pre-tax) of Acquisition integration costs, (c) a $50 million reduction of revenue (pre-tax), write-offs of $43 million (pre-tax) of certain accounts receivable and regulatory assets of RIE and $5 million (pre-tax) of expenses accrued in support of Rhode Island's decarbonization goals, all of which were conditions of the Acquisition, and (d) the income tax effect of these items, which was tax effected at the statutory federal income tax rate of 21%.

Developments *(PPL, LG&E and KU)*

Mill Creek Unit 5 Construction

In December 2022, LG&E and KU filed a CPCN with the KPSC requesting approval to construct a 640 MW net summer rating Natural Gas Combined Cycle (NGCC) combustion turbine at LG&E's Mill Creek Generating Station. In November 2023, the KPSC issued an order approving the request as well as the requested AFUDC accounting treatment for associated financing costs relating to the NGCC. The new NGCC facility will be jointly owned by LG&E (31%) and KU (69%). In February 2024, LG&E and KU entered into agreements to begin construction of Mill Creek Unit 5. Total project costs are estimated at approximately $1.0 billion, including AFUDC. Commercial operation of the facility is anticipated to begin in mid-2027.

See Note 7 for additional information on the CPCN filing.

Divestitures

Sale of Safari Holdings

On September 29, 2022, PPL signed a definitive agreement to sell all of Safari Holdings membership interests to Aspen Power Services, LLC (Aspen Power). On November 1, 2022, PPL completed the sale (the Transaction).

Final closing adjustments were completed during the year ended December 31, 2023, resulting in an increase to the loss on sale of $6 million ($5 million net of tax), which was recorded in "Other operation and maintenance" on the Statements of Income for the year ended December 31, 2023. A loss on sale of $60 million ($46 million net of tax benefit) was recorded in "Other operation and maintenance" on the Statements of Income for the year ended December 31, 2022.

In connection with the closing of the Transaction, PPL provided certain guarantees and other assurances. Certain of these guarantees and other assurances have been terminated as of January 8, 2024. See Note 12 to the Financial Statements for additional information.

Discontinued Operations

Summarized Results of Discontinued Operations

On June 14, 2021, PPL WPD Limited completed the sale of PPL's U.K. utility business to National Grid Holdings One plc (National Grid U.K.), a subsidiary of National Grid plc. For the year ended December 31, 2022, the operations of the U.K. utility business are included in "Income from Discontinued Operations (net of income taxes)" on the Statements of Income, with the only component being an income tax benefit of $42 million. There were no discontinued operations activities for the years ended December 31, 2024 or 2023.

10. Retirement and Postemployment Benefits

(All Registrants)

Defined Benefits

Certain employees of PPL's subsidiaries are eligible for pension benefits under non-contributory defined benefit pension plans with benefits based on length of service and final average pay, as defined by the plans.

Effective January 1, 2012, PPL's primary defined benefit pension plan was closed to all newly hired salaried employees. Effective July 1, 2014, PPL's primary defined benefit pension plan was closed to all newly hired bargaining unit employees. Newly hired employees are eligible to participate in the PPL Retirement Savings Plan, a 401(k) savings plan with enhanced employer contributions.

The defined benefit pension plans of LKE and its subsidiaries were closed to new salaried and bargaining unit employees hired after December 31, 2005. Employees hired after December 31, 2005 receive additional company contributions above the standard matching contributions to their savings plans. The pension plans sponsored by LKE and LG&E were merged effective January 1, 2020 into the LG&E and KU Pension Plan. The merged plan is sponsored by LKE. LG&E and KU participate in this plan.

The RIE defined benefit plans provide most union employees, as well as non-union employees hired before January 1, 2011, with a retirement benefit. Supplemental non-qualified, non-contributory executive retirement programs provide additional defined pension benefits for certain executives.

PPL and certain of its subsidiaries also provide supplemental retirement benefits to executives and other key management employees through unfunded nonqualified retirement plans.

Certain employees of PPL's subsidiaries are eligible for certain health care and life insurance benefits upon retirement through contributory plans. Effective January 1, 2014, the PPL Postretirement Medical Plan was closed to all newly hired salaried employees. Effective July 1, 2014, the PPL Postretirement Medical Plan was closed to all newly hired bargaining unit employees. Effective January 1, 2024, newly hired salaried employees and certain bargaining unit employees of LKE will no longer be eligible for postretirement medical benefits under the LKE Postretirement Plan. Postretirement health benefits may be paid from 401(h) accounts established as part of the PPL Retirement Plan and the LG&E and KU Pension Plan within the PPL Services Corporation Master Trust, funded VEBA trusts and company funds.

The Rhode Island postretirement benefit plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must contribute to the cost of their coverage.

(PPL)

The following table provides the components of net periodic defined benefit costs (credits) for PPL's pension and other postretirement benefit plans for the years ended December 31.

	Pension Benefits			Other Postretirement Benefits		
	2024	2023	2022	2024	2023	2022
Net periodic defined benefit costs (credits):						
Service cost	$ 35	$ 34	$ 51	$ 6	$ 6	$ 7
Interest cost	183	188	144	29	30	20
Expected return on plan assets	(299)	(309)	(276)	(30)	(30)	(28)
Amortization of:						
Prior service cost (credit)	3	6	8	1	1	1
Actuarial (gain) loss	10	2	51	(5)	(5)	(5)
Net periodic defined benefit costs (credits) prior to settlements and termination benefits	(68)	(79)	(22)	1	2	(5)
Settlements (a)	—	—	23	—	—	—
Net periodic defined benefit costs (credits)	$ (68)	$ (79)	$ 1	$ 1	$ 2	$ (5)
Other Changes in Plan Assets and Benefit Obligations Recognized in OCI and Regulatory Assets/Liabilities - Gross:						
Net (loss)/gain allocated at acquisition	$ —	$ —	$ 33	$ —	$ —	$ (49)
Settlement	—	—	(23)	—	—	—
Net (gain) loss	134	193	242	1	(6)	—
Prior service cost (credit)	(13)	2	—	—	—	—
Amortization of:						
Prior service (cost) credit	(3)	(6)	(8)	(1)	(1)	(1)
Actuarial gain (loss)	(10)	(2)	(51)	5	5	5
Total recognized in OCI and regulatory assets/liabilities	108	187	193	5	(2)	(45)
Total recognized in net periodic defined benefit costs, OCI and regulatory assets/liabilities	$ 40	$ 108	$ 194	$ 6	$ —	$ (50)

(a) Settlement charges incurred as a result of the amount of lump sum payment distributions, primarily from the LKE qualified pension plan. In accordance with existing regulatory accounting treatment, LG&E and KU have primarily maintained the settlement charge in regulatory assets to be amortized in accordance with existing regulatory practice. The portion of the settlement attributed to LKE's operations outside of the jurisdiction of the KPSC has been charged to expense.

For PPL's pension and postretirement benefits, the amounts recognized in OCI and regulatory assets/liabilities for the years ended December 31 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2024	2023	2022	2024	2023	2022
OCI	$ 25	$ 52	$ 142	$ 2	$ —	$ 13
Regulatory assets/liabilities	83	135	51	3	(2)	(58)
Total recognized in OCI and regulatory assets/liabilities	$ 108	$ 187	$ 193	$ 5	$ (2)	$ (45)

(PPL)

PPL uses base mortality tables issued by the Society of Actuaries for all defined benefit pension and other postretirement benefit plans. The Pri-2012 base table and the MP-2020 projection scale with varying adjustment factors based on the underlying demographic and geographic differences and experience of the plan participants was used for all periods.

The following weighted-average assumptions were used in the valuation of the benefit obligations at December 31.

	Pension Benefits		Other Postretirement Benefits	
	2024	2023	2024	2023
PPL				
Discount rate	5.93 %	5.52 %	5.91 %	5.54 %
Rate of compensation increase	3.43 %	3.43 %	3.44 %	3.43 %

The following weighted-average assumptions were used to determine the net periodic defined benefit costs for the years ended December 31.

	Pension Benefits			Other Postretirement Benefits		
	2024	2023	2022	2024	2023	2022
PPL						
Discount rate	5.52 %	5.52 %	3.35 %	5.54 %	5.54 %	3.54 %
Rate of compensation increase	3.43 %	3.43 %	3.74 %	3.43 %	3.43 %	2.84 %
Expected return on plan assets	8.25 %	8.25 %	7.25 %	7.28 %	7.38 %	6.52 %

(a) The expected long-term rates of return for pension and other postretirement benefits are based on management's projections using a best-estimate of expected returns, volatilities and correlations for each asset class. Each plan's specific current and expected asset allocations are also considered in developing a reasonable return assumption.

The following table provides the assumed health care cost trend rates for the years ended December 31:

	2024	2023	2022
PPL			
Health care cost trend rate assumed for next year			
– obligations	7.00 %	6.25 %	6.50 %
– cost	6.25 %	6.50 %	6.25 %
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)			
– obligations	5.00 %	5.00 %	5.00 %
– cost	5.00 %	5.00 %	5.00 %
Year that the rate reaches the ultimate trend rate			
– obligations	2033	2029	2029
– cost	2029	2029	2027

The funded status of PPL's plans at December 31 was as follows:

	Pension Benefits		Other Postretirement Benefits	
	2024	2023	2024	2023
Change in Benefit Obligation				
Benefit Obligation, beginning of period	$ 3,454	$ 3,333	$ 538	$ 534
Service cost	35	34	6	6
Interest cost	183	188	29	30
Participant contributions	—	—	8	9
Plan amendments	(13)	3	—	—
Actuarial (gain) loss	(131)	179	(4)	18
Settlements	—	(3)	—	—
Gross benefits paid	(284)	(280)	(56)	(59)
Federal subsidy	—	—	2	—
Benefit Obligation, end of period	3,244	3,454	523	538
Change in Plan Assets				
Plan assets at fair value, beginning of period	3,176	3,149	438	417
Actual return on plan assets	34	297	25	54
Employer contributions	10	13	14	16
Participant contributions	—	—	7	7
Transfer out (a)	—	—	(13)	—
Settlements	—	(3)	—	—
Gross benefits paid	(284)	(280)	(54)	(56)
Plan assets at fair value, end of period	2,936	3,176	417	438
Funded Status, end of period	$ (308)	$ (278)	$ (106)	$ (100)
Amounts recognized in the Balance Sheets consist of:				
Noncurrent asset	$ 19	$ 7	$ 8	$ 10
Current liability	(10)	(10)	(13)	(14)
Noncurrent liability	(317)	(275)	(101)	(96)
Net amount recognized, end of period	$ (308)	$ (278)	$ (106)	$ (100)
Amounts recognized in AOCI and regulatory assets/liabilities (pre-tax) consist of:				
Prior service cost (credit)	$ (6)	$ 11	$ 9	$ 10
Net actuarial (gain) loss	1,164	1,017	(90)	(96)
Total	$ 1,158	$ 1,028	$ (81)	$ (86)
Total accumulated benefit obligation for defined benefit pension plans	$ 3,116	$ 3,312		

(a) Transfer of excess funds from the PPL Bargaining Unit Retiree Health Plan VEBA to be used to pay medical claims of active bargaining unit employees.

For PPL's pension and other postretirement benefit plans, the amounts recognized in AOCI and regulatory assets/liabilities at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2024	2023	2024	2023
AOCI	$ 283	$ 235	$ 16	$ 14
Regulatory assets/liabilities	875	793	(97)	(100)
Total	$ 1,158	$ 1,028	$ (81)	$ (86)

The actuarial gain for pension plans in 2024 was primarily related to a change in the discount rate used to measure the benefit obligations of those plans. The actuarial loss for pension plans in 2023 was related to a change in the discount rate used to measure the benefit obligations of those plans.

The following tables provide information on pension plans where the projected benefit obligation (PBO) or accumulated benefit obligation (ABO) exceed the fair value of plan assets:

	PBO in excess of plan assets	
	2024	2023
Projected benefit obligation	$ 2,719	$ 2,891
Fair value of plan assets	2,392	2,606

	ABO in excess of plan assets	
	2024	2023
Accumulated benefit obligation	$ 2,618	$ 1,773
Fair value of plan assets	2,392	1,594

(PPL Electric)

Although PPL Electric does not directly sponsor any defined benefit plans, it is allocated a portion of the funded status and costs of plans sponsored by PPL Services based on its participation in those plans, which management believes are reasonable. The actuarially determined obligations of current active employees and retirees are used as a basis to allocate total plan activity, including active and retiree costs and obligations. Allocations to PPL Electric resulted in assets/(liabilities) at December 31 as follows:

	2024	2023
Pension	$ (83)	$ (65)
Other postretirement benefits	(60)	(55)

(LG&E)

Although LG&E does not directly sponsor any defined benefit plans, it is allocated a portion of the funded status and costs of plans sponsored by LKE. LG&E is also allocated costs of defined benefits plans from LKS for defined benefit plans sponsored by LKE. See Note 13 for additional information on costs allocated to LG&E from LKS. These allocations are based on LG&E's participation in those plans, which management believes are reasonable. The actuarially determined obligations of current active employees and retired employees of LG&E are used as a basis to allocate total plan activity, including active and retiree costs and obligations. Allocations to LG&E resulted in assets/(liabilities) at December 31 as follows:

	2024	2023
Pension	$ 29	$ 34
Other postretirement benefits	(44)	(44)

(KU)

Although KU does not directly sponsor any defined benefit plans, it is allocated a portion of the funded status and costs of plans sponsored by LKE. KU is also allocated costs of defined benefit plans from LKS for defined benefit plans sponsored by LKE. See Note 13 for additional information on costs allocated to KU from LKS. These allocations are based on KU's participation in those plans, which management believes are reasonable. The actuarially determined obligations of current active employees and retired employees of KU are used as a basis to allocate total plan activity, including active and retiree costs and obligations. Allocations to KU resulted in assets/(liabilities) at December 31 as follows.

	2024	2023
Pension	$ 46	$ 51
Other postretirement benefits	(8)	(9)

Plan Assets - Pension Plans

(PPL)

All of PPL's qualified pension plans are invested in the PPL Services Corporation Master Trust (the Master Trust) that also includes 401(h) accounts that are restricted for certain other postretirement benefit obligations of PPL, RIE and LKE. The investment strategy for the Master Trust is to achieve a risk-adjusted return on a mix of assets that, in combination with PPL's funding policy, will ensure that sufficient assets are available to provide long-term growth and liquidity for benefit payments, while also managing the duration of the assets to complement the duration of the liabilities. The Master Trust benefits from a wide diversification of asset types, investment fund strategies and external investment fund managers, and therefore has no significant concentration of risk.

The investment policy of the Master Trust outlines investment objectives and defines the responsibilities of the EBPB, external investment managers, investment advisor and trustee and custodian. The investment policy is reviewed annually by PPL's Board of Directors.

The EBPB created a risk management framework around the trust assets and pension liabilities. This framework considers the trust assets as being composed of three sub-portfolios: growth, immunizing and liquidity portfolios. The growth portfolio is comprised of investments that generate a return at a reasonable risk, including equity securities, certain debt securities and alternative investments. The immunizing portfolio consists of debt securities, generally with long durations, and derivative positions. The immunizing portfolio is designed to offset a portion of the change in the pension liabilities due to changes in interest rates. The liquidity portfolio consists primarily of cash and cash equivalents.

Target allocation ranges have been developed for each portfolio based on input from external consultants with a goal of limiting funded status volatility. The EBPB monitors the investments in each portfolio and seeks to obtain a target portfolio that emphasizes reduction of risk of loss from market volatility. In pursuing that goal, the EBPB establishes revised guidelines from time to time. EBPB investment guidelines as of the end of 2024 are presented below.

The asset allocation for the trust and the target allocation by portfolio at December 31 are as follows:

	Percentage of trust assets		2024
	2024	2023	Target Asset Allocation
Growth Portfolio	**55 %**	**54 %**	**55 %**
Equity securities	30 %	31 %	
Debt securities (a)	13 %	12 %	
Alternative investments	12 %	11 %	
Immunizing Portfolio	**43 %**	**43 %**	**43 %**
Debt securities (a)	35 %	36 %	
Derivatives (b)	8 %	7 %	
Liquidity Portfolio	**2 %**	**3 %**	**2 %**
Total	100 %	100 %	100 %

(a) Includes commingled debt funds, which PPL treats as debt securities for asset allocation purposes.
(b) Includes posted collateral to support derivative instruments subject to counterparty risk.

(PPL)

The fair value of net assets in the Master Trust by asset class and level within the fair value hierarchy was:

	December 31, 2024				December 31, 2023			
	Fair Value Measurements Using				Fair Value Measurements Using			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
PPL Services Corporation Master Trust								
Cash and cash equivalents	$ 212	$ 212	$ —	$ —	$ 226	$ 226	$ —	$ —
Equity securities:								
U.S. Equity	63	63	—	—	36	36	—	—
U.S. Equity fund measured at NAV (a)	461	—	—	—	542	—	—	—
International equity fund at NAV (a)	376	—	—	—	431	—	—	—
Commingled debt measured at NAV (a)	461	—	—	—	528	—	—	—
Debt securities:								
U.S. Treasury and U.S. government sponsored agency	150	149	1	—	159	159	—	—
Corporate	867	—	848	19	915	—	906	9
Other	13	—	13	—	14	—	13	1
Alternative investments:								
Real estate measured at NAV (a)	72	—	—	—	61	—	—	—
Private equity measured at NAV (a)	114	—	—	—	105	—	—	—
Private credit partnerships measured at NAV (a)	16	—	—	—	13	—	—	—
Hedge funds measured at NAV (a)	181	—	—	—	192	—	—	—
Derivatives	(38)	—	(38)	—	93	—	93	—
PPL Services Corporation Master Trust assets, at fair value	2,948	$ 424	$ 824	$ 19	3,315	$ 421	$ 1,012	$ 10
Receivables and payables, net (b)	102				(16)			
401(h) accounts restricted for other postretirement benefit obligations	(114)				(124)			
Total PPL Services Corporation Master Trust pension assets	$ 2,936				$ 3,175			

(a) In accordance with accounting guidance, certain investments that are measured at fair value using the net asset value per share (NAV), or its equivalent, have not been classified in the fair value hierarchy. The fair value amounts presented in the table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the statement of financial position.
(b) Receivables and payables, net represents amounts for investments sold/purchased but not yet settled along with interest and dividends earned but not yet received.

A reconciliation of the Master Trust assets classified as Level 3 at December 31, 2024 is as follows:

	Corporate debt
Balance at beginning of period	$ 10
Actual return on plan assets:	
Relating to assets still held at the reporting date	(2)
Relating to assets sold during the period	7
Purchases, sales and settlements	4
Balance at end of period	$ 19

A reconciliation of the Master Trust assets classified as Level 3 at December 31, 2023 is as follows:

	Corporate debt
Balance at beginning of period	$ 16
Actual return on plan assets:	
Relating to assets still held at the reporting date	(2)
Relating to assets sold during the period	4
Purchases, sales and settlements	(8)
Balance at end of period	$ 10

Cash and cash equivalents include deposits in banks, collateral accounts with brokers, and short-term investment funds, for which the carrying amounts disclosed approximate fair value based on their short-term nature.

The market approach is used to measure fair value of equity securities. The fair value measurements of equity securities (excluding commingled funds), which are generally classified as Level 1, are based on quoted prices in active markets. These securities represent actively and passively managed investments that are managed against various equity indices.

Investments in commingled equity and debt funds are categorized as equity securities. Investments in commingled equity funds include funds that invest in U.S. and international equity securities. Investments in commingled debt funds include funds that invest in a diversified portfolio of emerging market debt obligations, as well as funds that invest in investment grade long-duration fixed-income securities.

The fair value measurements of debt securities are generally based on evaluations that reflect observable market information, such as actual trade information for identical securities or for similar securities, adjusted for observable differences. The fair value of debt securities is generally measured using a market approach, including the use of pricing models, which incorporate observable inputs. Common inputs include benchmark yields, relevant trade data, broker/dealer bid/ask prices, benchmark securities and credit valuation adjustments. When necessary, the fair value of debt securities is measured using the income approach, which incorporates similar observable inputs as well as payment data, future predicted cash flows, collateral performance and new issue data. For the Master Trust, these securities represent investments in securities issued by U.S. Treasury and U.S. government sponsored agencies; investments securitized by residential mortgages, auto loans, credit cards and other pooled loans; investments in investment grade and non-investment grade bonds issued by U.S. companies across several industries; investments in debt securities issued by foreign governments and corporations.

Investments in real estate represent an investment in a partnership whose purpose is to manage investments in U.S. real estate properties diversified geographically and across major property types (e.g., office, industrial, retail, etc.). The partnership has limitations on the amounts that may be redeemed based on available cash to fund redemptions. Additionally, the general partner may decline to accept redemptions when necessary to avoid adverse consequences for the partnership, including legal and tax implications, among others. The fair value of the investment is based upon a partnership unit value.

Investments in private equity represent interests in partnerships in multiple early-stage venture capital funds and private equity fund of funds that use a number of diverse investment strategies. The partnerships have limited lives of at least 10 years, after which liquidating distributions will be received. Prior to the end of each partnership's life, the investment cannot be redeemed with the partnership; however, the interest may be sold to other parties, subject to the general partner's approval. Fair value is based on an ownership interest in partners' capital to which a proportionate share of net assets is attributed.

Investments in private credit represent pools of actively managed loans that span capital structure and borrower type. Strategies carry different types and levels of risk. Returns from those strategies will vary in terms of yield, fees generated, loan loss rates and the pace of principal repayment. Investments have limited lives of approximately 2-8 years. The investment cannot be redeemed with the general partner; however, the interest may be sold to other parties, subject to the general partner’s approval. Fair value is based on an ownership interest in partners’ capital to which a proportionate share of net assets is attributed.

At December 31, 2024, the Master Trust had unfunded commitments of $59 million that may be required during the lives of the real estate, private equity and private credit partnerships.

Investments in hedge funds represent investments in a fund of hedge funds. Hedge funds seek a return utilizing a number of diverse investment strategies. The strategies, when combined, aim to reduce volatility and risk while attempting to deliver positive returns under most market conditions. Major investment strategies for the fund of hedge funds include long/short equity, tactical trading, event driven, and relative value. Shares may be redeemed with 45 days prior written notice. The fund is subject to short term lockups and other restrictions. The fair value for the fund has been estimated using the net asset value per share.

The fair value measurements of derivative instruments utilize various inputs that include quoted prices for similar contracts or market-corroborated inputs. In certain instances, these instruments may be valued using models, including standard option valuation models and standard industry models. These securities primarily represent investments in treasury futures, total return swaps, interest rate swaps and swaptions (the option to enter into an interest rate swap), which are valued based on quoted prices, changes in the value of the underlying exposure or on the swap details, such as swap curves, notional amount, index and term of index, reset frequency, volatility and payer/receiver credit ratings.

Plan Assets - Other Postretirement Benefit Plans

The investment strategy with respect to other postretirement benefit obligations is to fund VEBA trusts and/or 401(h) accounts with voluntary contributions and to invest in a tax efficient manner. Excluding the 401(h) accounts included in the Master Trust, other postretirement benefit plans are invested in a mix of assets for long-term growth with an objective of earning returns that provide liquidity as required for benefit payments. These plans benefit from diversification of asset types, investment fund strategies and investment fund managers and, therefore, have no significant concentration of risk. Equity securities include investments in a large-cap commingled fund and a global equity exchange-traded fund. Ownership interests in commingled funds that invest entirely in debt securities are classified as equity securities, but treated as debt securities for asset allocation and target allocation purposes. Ownership interests in money market funds are treated as cash and cash equivalents for asset allocation and target allocation purposes. The asset allocation for the PPL VEBA trusts and the target allocation, by asset class, at December 31 are detailed below.

	Percentage of plan assets		Target Asset Allocation
	2024	2023	2024
Asset Class			
Equity securities	45 %	46 %	45 %
Debt securities (a)	49 %	48 %	49 %
Cash and cash equivalents (b)	6 %	6 %	6 %
Total	100 %	100 %	100 %

(a) Includes commingled debt funds and debt securities.
(b) Includes money market funds.

The fair value of assets in the other postretirement benefit plans by asset class and level within the fair value hierarchy was:

	December 31, 2024				December 31, 2023			
		Fair Value Measurement Using				Fair Value Measurement Using		
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
Money market funds	$ 19	$ 19	$ —	$ —	$ 20	$ 20	$ —	$ —
Equity securities:								
Large-cap equity fund measure at NAV (a)	71	—	—	—	76	—	—	—
Commingled debt fund measured at NAV (a)	78	—	—	—	84	—	—	—
Global equity exchange-traded fund	70	70	—	—	72	72	—	—
Long-term bond exchange-traded fund	74	74	—	—	74	74	—	—
Total VEBA trust assets, at fair value	312	$ 163	$ —	$ —	326	$ 166	$ —	$ —
Receivables and payables, net (b)	(9)				(12)			
401(h) account assets	114				124			
Total other postretirement benefit plan assets	$ 417				$ 438			

(a) In accordance with accounting guidance certain investments that are measured at fair value using the net asset value per share (NAV), or its equivalent, have not been classified in the fair value hierarchy. The fair value amounts presented in the table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the statement of financial position.
(b) Receivables and payables represent amounts for investments sold/purchased but not yet settled along with interest and dividends earned but not yet received.

Investments in money market funds represent investments in funds that invest primarily in a diversified portfolio of investment grade money market instruments, including, but not limited to, commercial paper, notes, repurchase agreements and other evidences of indebtedness with a maturity not exceeding 13 months from the date of purchase. The primary objective of the fund is a level of current income consistent with stability of principal and liquidity. Redemptions can be made daily on this fund.

Investments in large-cap equity securities represent investments in a passively managed equity index fund that invests in securities and a combination of other collective funds. Fair value measurements are not obtained from a quoted price in an active market but are based on firm quotes of net asset values per share as provided by the trustee of the fund. Redemptions can be made daily on this fund.

Investments in commingled debt securities represent investments in a fund that invests in a diversified portfolio of investment grade long-duration fixed income securities. Redemptions can be made daily on these funds.

Investments in global equity exchange-traded fund represents a passively-managed pooled investment vehicle that invests in developed market equities and is designed to track the performance of the MSCI World Index. Fair value measurements can be obtained from a quoted price on the exchange. Redemptions can be made daily on this fund.

Investments in long-term bond exchange-traded fund represents a passively-managed pooled investment vehicle that is designed to track the performance of the Bloomberg U.S. Long Government/Credit Float Adjusted Index, which includes all medium and larger issues of U.S. Government, investment-grade corporate and investment-grade international dollar-denominated bonds that have maturities of greater than 10 years. Fair value measurements can be obtained from a quoted price on the exchange. Redemptions can be made daily on this fund.

Expected Cash Flows - Defined Benefit Plans *(PPL)*

PPL does not plan to contribute to its pension plans in 2025, as PPL's defined benefit pension plans have the option to utilize available prior year credit balances to meet current and future contribution requirements.

PPL sponsors various non-qualified supplemental pension plans for which no assets are segregated from corporate assets. PPL expects to make approximately $10 million of benefit payments under these plans in 2025.

PPL is not required to make contributions to its other postretirement benefit plans that are funded through VEBA trusts and 401(h) accounts. However, postretirement benefits for certain non-union employees are not funded in such trusts. PPL pays for these benefits from its general assets and expects to make $13 million of postretirement benefit plan payments for these employees in 2025.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid by the plans and the following federal subsidy payments are expected to be received by PPL.

	Pension	Other Postretirement	
		Benefit Payment	Expected Federal Subsidy
2025	$ 304	$ 50	$ —
2026	297	49	—
2027	288	49	—
2028	282	48	—
2029	276	47	—
2030-2034	1,298	218	—

Savings Plans *(All Registrants)*

Substantially, all employees of PPL's subsidiaries are eligible to participate in deferred savings plans (401(k)s). Employer contributions to the plans were:

	2024	2023	2022
PPL	$ 53	$ 48	$ 36
PPL Electric	9	8	6
LG&E	8	8	7
KU	6	6	5

11. Jointly Owned Facilities

(PPL, LG&E and KU)

At December 31, 2024 and 2023, the Balance Sheets reflect the owned interests in the generating plants listed below.

	Ownership Interest	Electric Plant	Accumulated Depreciation	Construction Work in Progress
PPL				
December 31, 2024				
Trimble County Unit 1	75.00 %	$ 462	$ 124	$ 1
Trimble County Unit 2	75.00 %	1,549	323	10
December 31, 2023				
Trimble County Unit 1	75.00 %	$ 464	$ 110	$ —
Trimble County Unit 2	75.00 %	1,490	300	49
LG&E				
December 31, 2024				
E.W. Brown Units 6-7	38.00 %	$ 53	$ 29	$ —
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00 %	52	30	—
Trimble County Unit 1	75.00 %	462	124	1
Trimble County Unit 2	14.25 %	472	79	5
Trimble County Units 5-6	29.00 %	37	19	—
Trimble County Units 7-10	37.00 %	82	41	1
Cane Run Unit 7	22.00 %	137	27	—
E.W. Brown Solar Unit	39.00 %	10	4	—
Solar Share	44.00 %	3	—	—
Mercer Solar	37.00 %	10	—	1
Mill Creek 5	31.00 %	—	—	74
Brown Wind	36.00 %	—	—	—
December 31, 2023				
E.W. Brown Units 6-7	38.00 %	$ 53	$ 27	$ —
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00 %	52	29	—
Trimble County Unit 1	75.00 %	464	110	—
Trimble County Unit 2	14.25 %	447	74	25
Trimble County Units 5-6	29.00 %	37	17	—
Trimble County Units 7-10	37.00 %	82	39	—
Cane Run Unit 7	22.00 %	127	25	3
E.W. Brown Solar Unit	39.00 %	10	3	—
Solar Share	44.00 %	3	—	—
Mercer Solar	37.00 %	7	—	—
Mill Creek 5	31.00 %	—	—	2
Brown Wind	36.00 %	—	—	—
KU				
December 31, 2024				
E.W. Brown Units 6-7	62.00 %	$ 87	$ 48	$ —
Paddy's Run Unit 13 & E.W. Brown Unit 5	47.00 %	46	26	—
Trimble County Unit 2	60.75 %	1,077	224	5
Trimble County Units 5-6	71.00 %	87	44	—
Trimble County Units 7-10	63.00 %	136	69	1
Cane Run Unit 7	78.00 %	485	95	1
E.W. Brown Solar Unit	61.00 %	16	6	—
Solar Share	56.00 %	4	1	—
Mercer Solar	63.00 %	16	—	2
Mill Creek 5	69.00 %	—	—	164
Brown Wind	64.00 %	1	—	—
December 31, 2023				
E.W. Brown Units 6-7	62.00 %	$ 87	$ 45	$ —
Paddy's Run Unit 13 & E.W. Brown Unit 5	47.00 %	46	25	—
Trimble County Unit 2	60.75 %	1,043	227	24
Trimble County Units 5-6	71.00 %	86	41	—
Trimble County Units 7-10	63.00 %	135	65	—
Cane Run Unit 7	78.00 %	449	90	10
E.W. Brown Solar Unit	61.00 %	16	5	—
Solar Share	56.00 %	4	—	—
Mercer Solar	63.00 %	12	—	1
Mill Creek 5	69.00 %	—	—	3
Brown Wind	64.00 %	1	—	—

Each subsidiary owning these interests provides its own funding for its share of the facility. Each receives a portion of the total output of the generating plants equal to its percentage ownership. The share of fuel and other operating costs associated with the plants is included in the corresponding operating expenses on the Statements of Income.

12. Commitments and Contingencies

Energy Purchase Commitments

(PPL, LG&E and KU)

LG&E and KU enter into purchase contracts to supply the coal and natural gas requirements for generation facilities and LG&E's retail natural gas supply operations. These contracts include the following commitments:

Contract Type	Maximum Maturity Date
Natural Gas Fuel	2026
Natural Gas Retail Supply	2025
Coal	2030
Coal Transportation and Fleeting Services	2033
Natural Gas Transportation	2055

LG&E and KU have a PPA with OVEC expiring in June 2040. See footnote (d) to the table in "Guarantees and Other Assurances" below for information on the OVEC power purchase contract. Future obligations for power purchases from OVEC are demand payments, comprised of debt-service payments and contractually-required reimbursements of plant operating, maintenance and other expenses, and are projected as follows:

	LG&E	KU	Total
2025	$ 25	$ 11	$ 36
2026	27	12	39
2027	27	12	39
2028	25	11	36
2029	25	11	36
Thereafter	177	79	256
Total	$ 306	$ 136	$ 442

LG&E and KU had total energy purchases under the OVEC PPA for the years ended December 31 as follows:

	2024	2023	2022
LG&E	$ 21	$ 20	$ 21
KU	9	9	9
Total	$ 30	$ 29	$ 30

(PPL)

RIE enters into purchase contracts to supply electricity for electricity distribution operations and for the delivery, storage and supply of natural gas for RIE's retail natural gas operations.

These contracts include the following commitments:

Contract Type	Maximum Maturity Date
Electric power	2027
Gas-related	Beyond 2030

RIE's commitments under these long-term contracts subsequent to December 31, 2024 are summarized in the table below.

	Total	2025	2026-2027	2028-2029	Thereafter
Energy Purchase Obligations	$ 936	$ 274	$ 240	$ 122	$ 300

Long-term Contracts for Renewable Energy *(PPL)*

Several of the obligations included in the table above relate to certain long-term contracts for renewable energy, including:

- the Deepwater Wind PPA, involving a proposal for a small-scale renewable energy generation project of up to eight offshore wind turbines with an aggregate nameplate capacity of up to 30 MW to benefit the Town of New Shoreham and an underwater cable to Block Island, which entered into service in October 2016;
- the Three-State Procurement, involving six clean energy long-term contracts pursuant to the Rhode Island Long-Term Contracting Standard (LTCS) of which 36.427 MW is currently operational and with respect to which RIE collects 2.75% remunerations in the annual payments pursuant to the LTCS; and
- the Offshore Wind Energy Procurement, pursuant to a 20-year PPA with Deep Water Wind Rev I, LLC (Revolution Wind), with an expected nameplate capacity of 408 MW expected to be operational in 2026; this contract was approved without remuneration but allows RIE to seek costs incurred under the agreement.

In addition, RIE is obligated under the LTCS (as amended in 2014) to annually solicit for renewable projects until 90 MW of renewable contracting capacity has been secured. The RIPUC-approved solicitations currently in service include: (i) a 15-year PPA with Orbit Energy Rhode Island, LLC for a 3.2 MW nameplate anaerobic digester biogas project located in Johnston, Rhode Island, placed in service in 2017, (ii) a 15-year PPA with Black Bear Development Holdings, LLC for a 3.9 MW nameplate run-of-river hydroelectric plant located in Orono, Maine, placed in service in 2013, (iii) a 15-year PPA with Copenhagen Wind Farm, LLC for an 80 MW nameplate land-based wind project located in Denmark, New York, placed in service in 2018, and (iv) a 15-year PPA with Rhode Island LFG Genco, LLC for a 32.1 MW nameplate combined cycle combustion turbine generating facility fueled by a landfill gas project located in Johnston, Rhode Island, placed in service in 2013. On October 7, 2024, RIE issued an RFP soliciting 20 MW through 150 MW of nameplate capacity of renewable contracting capacity; this solicitation is driven by a terminated PPA and is required in order to fulfill the 90 MW under LTCS.

In addition to the LTCS, RIE has conditionally awarded 200 MW under the 2023 Rhode Island Offshore Wind RFP for newly developed offshore wind energy projects, under the Affordable Clean Energy Security Act (ACES), as amended in 2022. RIE is currently in the contract negotiation period. RIE must negotiate in good faith to achieve a commercially reasonable contract and may file such contract with the RIPUC for approval once negotiations are complete, which is tentatively scheduled for March 2025.

As approved by the RIPUC, RIE is allowed to pass through commodity-related/purchased power costs to customers and collect remuneration equal to 2.75% for long-term contracts approved prior to January 1, 2022, pursuant to LTCS as amended in 2022, and that have achieved commercial operation. For long-term contracts approved pursuant to LTCS or ACES, both as amended, on or after January 1, 2022, RIE is entitled to financial remuneration equal to 1.0% through December 31, 2026, for those projects that are commercially operating. For long-term contracts approved pursuant to LTCS or ACES on or after January 1, 2027, RIE is not entitled to any financial remuneration, unless otherwise granted by the RIPUC. Also, the 2022 amendments to LTCS and ACES added a provision, which provides that for any calendar year in which RIE's actual return on equity exceeds the return on equity allowed by the RIPUC in the last general rate case, the RIPUC may adjust any or all remuneration to assure that such remuneration does not result in or contribute toward RIE earning above its allowed return for such calendar year.

Legal Matters

(All Registrants)

PPL and its subsidiaries are involved in legal proceedings, claims and litigation in the ordinary course of business. PPL and its subsidiaries cannot predict the outcome of such matters, or whether such matters may result in material liabilities, unless otherwise noted.

Narragansett Electric Litigation *(PPL)*

Energy Efficiency Programs Investigation

Narragansett Electric, while under the ownership of National Grid, performed an internal investigation into conduct associated with its energy efficiency programs. On June 27, 2022, the RIPUC opened a new docket (RIPUC Docket No. 22-05-EE) to investigate RIE's actions and the actions of employees of National Grid USA and affiliates during the time RIE was a National Grid USA affiliate being provided services by National Grid USA Service Company, Inc. relating to the manipulation of the reporting of invoices affecting the calculation of past energy efficiency shareholder incentives and the resulting impact on customers. The Rhode Island Attorney General and National Grid USA intervened in the docket and the Rhode Island Division of Public Utilities and Carriers (the Division) is an automatic party in the docket.

On January 19, 2023, the Division filed a motion to dismiss RIPUC Docket No. 22-05-EE without prejudice. As grounds for its motion, the Division stated that sufficient evidence exists in the docket to warrant an independent summary investigation by the Division. If the Division finds sufficient grounds, the Division may proceed to a formal hearing regarding the matters under investigation. Upon the conclusion of its investigation, the Division will provide the RIPUC with a report outlining the Division's findings and final decision. On January 30, 2023, the Rhode Island Attorney General filed an objection to the Division's motion to dismiss; RIE and National Grid USA each filed responses with the RIPUC requesting that any additional action taken by the RIPUC or the Division be considered after National Grid USA completes its internal investigation report, which National Grid USA filed with the RIPUC on March 10, 2023. On February 24, 2023, the Division initiated the independent summary investigation that it had referenced in its motion to dismiss. The RIPUC held a hearing on March 28, 2023 to hear oral arguments regarding the Division's motion to dismiss and subsequently denied the motion. On November 27, 2023, the Division filed testimony recommending the RIPUC disallow a portion of the performance incentive awarded from 2012 through 2021. On January 19, 2024, the Division and the Rhode Island Attorney General filed their respective briefs recommending that the RIPUC assess financial penalties on the company. The Division also recommended that the RIPUC consider further regulatory investigations and analysis within each of the energy efficiency dockets from 2012 through 2020, to confirm the accuracy of claimed savings and to document all conduct and actions that would trigger penalties. On April 2, 2024, the RIPUC issued an amended order that expressly expands the scope of the proceeding to address issues of accountability and the question of whether statutory penalties should be assessed against RIE relating to the manipulation of the reporting of invoices affecting the recovery of past shareholder incentives and the resulting impact on RIE's customers. This RIPUC proceeding remains open and, in parallel, the Division's summary investigation remains ongoing. In the RIPUC proceeding, RIE and National Grid USA filed testimony on June 14, 2024, supporting their position that the appropriate amount to be refunded to the energy efficiency program is less than $1 million. The Division's current position is that $11 million is the appropriate amount to be refunded to the energy efficiency program. This testimony does not address potential statutory penalties and the Division's testimony on potential statutory penalties is due February 28, 2025. The Division's testimony on accountability and potential statutory penalties is currently due February 21, 2025, and RIE's and National Grid's reply testimony will occur at the evidentiary hearings scheduled for March 2025. At this time, it is not possible to predict the final outcome, or determine the total amount of any additional liabilities that may be incurred by RIE in connection with this matter or the Division's summary investigation. RIE does not expect this matter will have a material adverse effect on its results of operations, financial position or cash flows.

E.W. Brown Environmental Assessment *(PPL and KU)*

KU is undertaking extensive remedial measures at the E.W. Brown plant including closure of the former ash pond, implementation of a groundwater remedial action plan and performance of a corrective action plan including aquatic study of adjacent surface waters and risk assessment. The aquatic study and risk assessment are being undertaken pursuant to a 2017 agreed Order with the Kentucky Energy and Environment Cabinet (KEEC). KU conducted sampling of Herrington Lake in 2017 and 2018. In June 2019, KU submitted to the KEEC the required aquatic study and risk assessment, conducted by an independent third-party consultant, finding that discharges from the E.W. Brown plant have not had any significant impact on Herrington Lake and that the water in the lake is safe for recreational use and meets safe drinking water standards. On May 31, 2021, the KEEC approved the report and released a response to public comments. On August 6, 2021, KU submitted a *Supplemental Remedial Alternatives Analysis* report to the KEEC that outlines proposed additional fish, water, and sediment testing. On February 18, 2022, the KEEC provided approval to KU to proceed with the proposed sampling, which commenced in the spring of 2022. On November 17, 2022, KU submitted a *Supplemental Performance Monitoring Report* to the KEEC finding that there are no significant unaddressed risks to human health or the environment at the plant. KU revised the *Supplemental Performance Monitoring Report* on June 8, 2023, in response to KEEC comments from April 24, 2023. On September 1, 2023, the KEEC requested KU to propose additional monitoring or remedial measures. KU submitted a revised *Supplemental Performance Monitoring and Corrective Action Completion* on December 28, 2023. In August 2024, KU submitted a proposed environmental covenant to the KEEC specifying certain site restrictions. Discussions between KU and the KEEC are ongoing.

Water/Waste *(PPL, LG&E and KU)*

ELGs

In 2015, the EPA finalized ELGs for wastewater discharge permits for new and existing steam electricity generating facilities. These guidelines require deployment of additional control technologies providing physical, chemical and biological treatment and mandate operational changes including "zero discharge" requirements for certain wastewaters. The implementation date for individual generating stations was to be determined by the states on a case-by-case basis according to criteria provided by the EPA. In September 2017, the EPA issued a rule to postpone the compliance date for certain requirements. In October 2020, the EPA issued revisions to its best available technology standards for certain wastewaters and potential extensions to compliance dates (the Reconsideration Rule). On May 9, 2024, the EPA issued a final rule modifying the 2020 ELG revisions. The rule increases the stringency of previous control technology and zero discharge requirements, revises certain exemptions for generating units planned for retirement, and requires case-by-case limitations for legacy wastewaters based on the best professional judgment of the state regulators. Legal challenges to the final rule have been consolidated before the U.S. Court of Appeals for the Eighth Circuit. The final rule is currently under evaluation by PPL, LG&E, and KU, but could potentially result in significant operational changes and additional controls for LG&E and KU plants. The ELGs are expected to be implemented by the states or applicable permitting authorities in the course of their normal permitting activities. Certain costs are included in the Registrants' capital plans and expected to be recovered from customers through rate recovery mechanisms, but additional costs and recovery will depend on further regulatory developments at the state level.

CCRs

In 2015, the EPA issued a final rule governing management of CCRs which include fly ash, bottom ash and sulfur dioxide scrubber wastes (2015 CCR Rule). The 2015 CCR Rule imposed extensive new requirements for certain CCR impoundments and landfills, including public notifications, location restrictions, design and operating standards, groundwater monitoring and corrective action requirements, and closure and post-closure care requirements, and specifies restrictions relating to the beneficial use of CCRs. In January 2022, the EPA issued several proposed regulatory determinations, facility notifications, and public announcements which indicate increased scrutiny by the EPA to determine the adequacy of measures taken by facility owners and operators to achieve closure of CCR surface impoundments and landfills. In particular, the agency indicated that it will focus on certain practices which it views as posing a threat of continuing groundwater contamination. On May 8, 2024, the EPA issued a final rule (2024 CCR Rule) establishing regulatory requirements for inactive surface impoundments at inactive electricity generation facilities (legacy impoundments). The 2024 CCR Rule also establishes identification, groundwater monitoring, corrective action, closure, and post-closure care requirements for all CCR management units, as defined in the rule, at regulated CCR facilities regardless of how or when the CCR was placed. The rule also requires LG&E and KU to complete applicability determinations, implement site security measures, initiate weekly inspections and monthly monitoring of the impoundment, create a website, and complete hazard assessments and reports for its legacy impoundments. Additionally, the rule could potentially subject CCR management units that have previously completed remedial action and closure and certain beneficial use projects to additional federal regulatory requirements. Legal challenges to the rule have been filed in the D.C. Circuit Court, and oral argument is expected in the second half of 2025.

In connection with the 2015 CCR Rule, LG&E and KU recorded adjustments to existing AROs beginning in 2015. In connection with the 2024 CCR Rule, in the second quarter of 2024, LG&E and KU recognized ARO obligations related to preliminary risk assessments, facility evaluations, feasibility studies and sampling. See Note 18 for additional information. The results of those evaluations, as well as future guidance, regulatory determinations, rulemakings, implementation determinations and other developments could potentially require revisions to current LG&E and KU compliance plans including additional monitoring and remediation at surface impoundments and landfills, the cost of which could be material. PPL, LG&E and KU are unable to predict the outcome of the ongoing litigation, rulemaking, and regulatory determinations or potential impacts on current LG&E and KU compliance plans. PPL, LG&E and KU are currently finalizing or revising closure plans and schedules in accordance with applicable regulations and further material changes to AROs, current capital plans or operating costs may be required as estimates are refined based on closure developments, groundwater monitoring results, and regulatory or legal proceedings. Costs relating to this rule are expected to be subject to rate recovery.

LG&E and KU received KPSC approval for a compliance plan associated with the 2015 CCR Rule providing for the closure of impoundments at the Mill Creek, Trimble County, E.W. Brown, and Ghent stations, and construction of process water management facilities at those plants. In addition to the foregoing measures required for compliance with the federal CCR Rule, KU also received KPSC approval for its plans to close impoundments at the retired Green River, Pineville and Tyrone plants to comply with applicable state law. LG&E and KU have completed planned closure measures at most of the subject impoundments and have commenced post closure groundwater monitoring as required at those facilities. LG&E and KU generally expect to complete all impoundment closures within five years of commencement, although a longer period may be required to complete closure of some facilities. Associated costs are expected to be subject to rate recovery.

Superfund and Other Remediation

(All Registrants)

The Registrants are potentially responsible for investigating and remediating contamination under the federal Superfund program and similar state programs. Actions are under way at certain sites including former manufactured gas plants in Pennsylvania, Rhode Island and Kentucky previously owned or operated by, or currently owned by predecessors or affiliates of, PPL subsidiaries.

Depending on the outcome of investigations at identified sites where investigations have not begun or been completed, or developments at sites for which information is incomplete, additional costs of remediation could be incurred. PPL, PPL Electric, LG&E and KU lack sufficient information about such additional sites to estimate any potential liability or range of reasonably possible losses, if any, related to these sites. Such costs, however, are not currently expected to be significant.

The EPA is evaluating the risks associated with polycyclic aromatic hydrocarbons and naphthalene, chemical by-products of manufactured gas plant operations. As a result, individual states may establish stricter standards for water quality and soil cleanup, that could require several PPL subsidiaries to take more extensive assessment and remedial actions at former manufactured gas plants. The Registrants cannot reasonably estimate a range of possible losses, if any, related to these matters.

(PPL and PPL Electric)

PPL Electric is a potentially responsible party for a share of clean-up costs at certain sites. Cleanup actions have been or are being undertaken at these sites as requested by governmental agencies, the costs of which have not been and are not expected to be significant to PPL Electric.

At December 31, 2024 and December 31, 2023, PPL Electric had a recorded liability of $8 million and $8 million, representing its best estimate of the probable loss incurred to remediate these sites.

(PPL)

RIE is a potentially responsible party for a share of clean-up costs at certain sites including former manufactured gas plant facilities formerly owned by the Blackstone Valley Gas and Electric Company and the Rhode Island gas distribution assets of the New England Gas division of Southern Union Company and electric operations at certain RIE facilities. RIE is currently investigating and remediating, as necessary, those sites and certain other properties under agreements with governmental agencies, the costs of which have not been and are not expected to be significant to PPL.

At December 31, 2024 and December 31, 2023, RIE had a recorded liability of $98 million and $99 million, representing its best estimate of the remaining costs of environmental remediation activities. These undiscounted costs are expected to be incurred over approximately 30 years and to be subject to rate recovery. However, remediation costs for each site may be materially higher than estimated, depending on changing technologies and regulatory standards, selected end uses for each site, and actual environmental conditions encountered. RIE has recovered amounts from certain insurers and potentially responsible parties, and, where appropriate, may seek additional recovery from other insurers and potentially responsible parties, but it is uncertain whether, and to what extent, such efforts will be successful.

The RIPUC has approved two settlement agreements that provide for rate recovery of qualified remediation costs of certain contaminated sites located in Rhode Island and Massachusetts. Rate-recoverable contributions for electric operations of approximately $3 million are added annually to RIE's Environmental Response Fund, established with RIPUC approval in March 2000 to address such costs, along with interest and any recoveries from insurance carriers and other third-parties. In addition, RIE recovers approximately $1 million annually for gas operations under a distribution adjustment charge in which the qualified remediation costs are amortized over 10 years. See Note 7 for additional information on RIE's recorded environmental regulatory assets and liabilities.

Regulatory Issues

See Note 7 for information on regulatory matters related to utility rate regulation.

<u>Electricity - Reliability Standards</u>

The NERC is responsible for establishing and enforcing mandatory reliability standards (Reliability Standards) regarding the bulk electric system in North America. The FERC oversees this process and independently enforces the Reliability Standards.

The Reliability Standards have the force and effect of law and apply to certain users of the bulk electric system, including electric utility companies, generators and marketers. Under the Federal Power Act, the FERC may assess civil penalties for certain violations.

PPL Electric, LG&E, KU and RIE monitor their compliance with the Reliability Standards and self-report or self-log potential violations of applicable reliability requirements whenever identified, and submit accompanying mitigation plans, as required. The resolution of a small number of potential violations is pending. Penalties incurred to date have not been significant. Any Regional Reliability Entity determination concerning the resolution of violations of the Reliability Standards remains subject to the approval of the NERC and the FERC.

In the course of implementing their programs to ensure compliance with the Reliability Standards by those PPL affiliates subject to the standards, certain other instances of potential non-compliance may be identified from time to time. The Registrants cannot predict the outcome of these matters, and an estimate or range of possible losses cannot be determined.

<u>Gas - Security Directives</u> *(PPL and LG&E)*

In May and July of 2021, the Department of Homeland Security's (DHS) Transportation Security Administration released two security directives applicable to certain notified owners and operators of natural gas pipeline facilities (including local distribution companies) that the Transportation Security Administration has determined to be critical. The Transportation Security Administration has determined that LG&E is within the scope of the directive, while RIE has not been notified of this distinction. The first security directive required notified owners/operators to implement cybersecurity incident reporting to the DHS, designate a cybersecurity coordinator, and perform a gap assessment of current entity cybersecurity practices against certain voluntary Transportation Security Administration security guidelines and report relevant results and proposed mitigation to applicable DHS agencies. The second security directive, revised in July of 2024, requires refinement of the cybersecurity implementation plan and the cybersecurity assessment plan. LG&E does not believe the security directives have had or will have a significant impact on LG&E's operations or financial condition.

Other

<u>Guarantees and Other Assurances</u>

(All Registrants)

In the normal course of business, the Registrants enter into agreements that provide financial performance assurance to third parties on behalf of certain subsidiaries. Examples of such agreements include guarantees, stand-by letters of credit issued by financial institutions and surety bonds issued by insurance companies. These agreements are entered into primarily to support or enhance the creditworthiness attributed to a subsidiary on a stand-alone basis or to facilitate the commercial activities in which these subsidiaries engage.

(PPL)

PPL fully and unconditionally guarantees all of the debt obligations of PPL Capital Funding.

(All Registrants)

The table below details guarantees provided as of December 31, 2024. "Exposure" represents the estimated maximum potential amount of future payments that could be required to be made under the guarantee. The Registrants believe the probability of expected payment/performance under each of these guarantees is remote, except for the guarantees and indemnifications related to the sale of Safari Holdings, which PPL believes are reasonably possible but not probable of occurring. For reporting purposes, on a consolidated basis, the guarantees of PPL include the guarantees of its subsidiary Registrants.

	Exposure at December 31, 2024		Expiration Date
PPL			
Indemnifications related to certain tax liabilities related to the sale of the U.K. utility business	£ 50	(a)	2028
PPL guarantee of Safari payment obligations under certain sale/leaseback financing transactions related to the sale of Safari Holdings	$ 100	(b)	2028
Indemnifications for losses suffered related to items not covered by Aspen Power's representation and warranty insurance associated with the sale of Safari Holdings	140	(c)	Various
LG&E and KU			
LG&E and KU obligation of shortfall related to OVEC		(d)	

(a) PPL WPD Limited entered into a Tax Deed dated June 9, 2021 in which it agreed to a tax indemnity regarding certain potential tax liabilities of the entities sold with respect to periods prior to the completion of the sale, subject to customary exclusions and limitations. Because National Grid Holdings One plc, the buyer, agreed to purchase indemnity insurance, the amount of the cap on the indemnity for these liabilities is £1, except with respect to certain surrenders of tax losses, for which the amount of the cap on the indemnity is £50 million.
(b) PPL guaranteed the payment obligations of Safari under certain sale/leaseback financing transactions executed by Safari. These guarantees will remain in place until Safari exercises its option to buy-out the projects under the sale/leaseback financings by the year 2028. Safari will indemnify PPL for any payments made by PPL or claims against PPL under the sale/leaseback transaction guarantees up to $25 million.
(c) Aspen Power has obtained representation and warranty insurance, therefore, PPL generally has no liability for its representations and warranties under the agreement except for losses suffered related to items not covered. Expiration of these indemnifications range from 18 months to 6 years from the date of the closing of the transaction, and PPL's aggregate liability for these claims will not exceed $140 million subject to certain adjustments plus the support obligations provided by PPL under sale-leaseback financings and PPAs that will be replaced by Aspen Power. PPL's support obligations related to the PPAs were replaced by Aspen Power and terminated on January 8, 2024.
(d) Pursuant to the OVEC power purchase contract, LG&E and KU are obligated to pay for their share of OVEC's excess debt service, post-retirement and decommissioning costs, as well as any shortfall from amounts included within a demand charge designed and expected to cover these costs over the term of the contract. PPL's proportionate share of OVEC's outstanding debt was $81 million at December 31, 2024, consisting of LG&E's share of $56 million and KU's share of $25 million. The maximum exposure and the expiration date of these potential obligations are not presently determinable. See "Energy Purchase Commitments" above for additional information on the OVEC power purchase contract.

The Registrants provide other miscellaneous guarantees through contracts entered into in the normal course of business. These guarantees are primarily in the form of indemnification or warranties related to services or equipment and vary in duration. The amounts of these guarantees often are not explicitly stated, and the overall maximum amount of the obligation under such guarantees cannot be reasonably estimated. Historically, no significant payments have been made with respect to these types of guarantees and the probability of payment/performance under these guarantees is remote.

PPL, on behalf of itself and certain of its subsidiaries, maintains insurance that covers liability assumed under contract for bodily injury and property damage. The coverage provides maximum aggregate coverage of $231 million. This insurance may be applicable to obligations under certain of these contractual arrangements.

13. Related Party Transactions

Wholesale Sales and Purchases *(LG&E and KU)*

LG&E and KU jointly dispatch their generation units with the lowest cost generation used to serve their retail customers. When LG&E has excess generation capacity after serving its own retail customers and its generation cost is lower than that of KU, KU purchases electricity from LG&E and vice versa. These transactions are reflected in the Statements of Income as "Electric revenue from affiliate" and "Energy purchases from affiliate" and are recorded at a price equal to the seller's fuel cost plus any split savings. Savings realized from such intercompany transactions are shared equally between both companies. The volume of energy each company has to sell to the other is dependent on its retail customers' needs and its available generation.

Support Costs *(PPL Electric, LG&E and KU)*

PPL Services and LKS provide the Registrants, their respective subsidiaries and each other with administrative, management and support services. For all services companies, the costs of directly assignable and attributable services are charged to the respective recipients as direct support costs. General costs that cannot be directly attributed to a specific entity are allocated and charged to the respective recipients as indirect support costs. PPL Services and LKS use a three-factor methodology that includes the applicable recipients' invested capital, operation and maintenance expenses and number of employees to allocate indirect costs. PPL Services may also use a ratio of overall direct and indirect costs or a weighted average cost ratio. PPL Services and LKS charged the following amounts for the years ended December 31, including amounts applied to accounts that are further distributed between capital and expense on the books of the recipients, based on methods that are believed to be reasonable.

	2024	2023	2022
PPL Electric from PPL Services	$ 227	$ 222	$ 241
LG&E from LKS	105	115	153
LG&E from PPL Services	66	42	13
KU from LKS	130	150	171
KU from PPL Services	65	48	14

In addition to the charges for services noted above, LKS makes payments on behalf of LG&E and KU for fuel purchases and other costs for products or services provided by third parties. LG&E and KU also provide services to each other and to LKS. Billings between LG&E and KU relate to labor and overheads associated with union and hourly employees performing work for the other company, charges related to jointly-owned generating units and other miscellaneous charges. Tax settlements between PPL and LG&E and KU are reimbursed through LKS.

Intercompany Borrowings

(PPL Electric)

CEP Reserves maintains a $800 million revolving line of credit with a PPL Electric subsidiary. At December 31, 2024, CEP Reserves had $222 million of borrowings outstanding. At December 31, 2023, CEP Reserves had no borrowings outstanding. The interest rates on borrowings are equal to one-month SOFR plus a spread. Interest income is reflected in "Interest Income from Affiliate" on the Income Statements.

(LG&E and KU)

LG&E participates in an intercompany money pool agreement whereby LKE and/or KU make available to LG&E funds up to the difference between LG&E's FERC borrowing limit and LG&E's commercial paper limit at an interest rate based on the lower of a market index of commercial paper issues and two additional rate options based on SOFR. At December 31, 2024, LG&E's money pool unused capacity was $682 million. At December 31, 2024 LG&E had borrowings outstanding of $43 million from KU and/or LKE. At December 31, 2023, LG&E's borrowings outstanding from KU and/or LKE were not significant.

KU participates in an intercompany money pool agreement whereby LKE and/or LG&E make available to KU funds up to the difference between KU's FERC borrowing limit and KU's commercial paper limit at an interest rate based on the lower of a market index of commercial paper issues and two additional rate options based on SOFR. At December 31, 2024, KU's money pool unused capacity was $437 million. At December 31, 2024 KU had borrowings outstanding of $73 million from LG&E and/or LKE. At December 31, 2023, KU's borrowings outstanding from LG&E and/or LKE were not significant.

VEBA Funds Receivable

(PPL Electric)

In 2018, PPL received a favorable private letter ruling from the IRS permitting a transfer of excess funds from the PPL Bargaining Unit Retiree Health Plan VEBA to a new subaccount within the VEBA, to be used to pay medical claims of active bargaining unit employees. In October 2024, additional excess funds were removed from the PPL Bargaining Unit Retiree Health Plan VEBA and deposited into the existing subaccount within the VEBA to be used to pay medical claims of active bargaining unit employees. Based on PPL Electric's participation in PPL's Other Postretirement Benefit plan, PPL Electric was allocated a portion of the excess funds from PPL Services. These funds have been recorded as an intercompany receivable on PPL Electric's balance sheets. The receivable balance decreases as PPL Electric pays incurred medical claims and is reimbursed by PPL Services. The intercompany receivable balance associated with these funds was $7 million at December 31, 2024, of which $4 million was reflected in "Accounts receivable from affiliates" and $3 million was reflected in "Other noncurrent assets" on PPL Electric's balance sheets. There was no intercompany receivable balance associated with these funds at December 31, 2023, as the initial allocation from the 2018 private letter ruling was depleted.

Other *(PPL Electric, LG&E and KU)*

See Note 1 for discussions regarding the intercompany tax sharing agreement (for PPL Electric, LG&E and KU) and intercompany allocations of stock-based compensation expense (for PPL Electric). For PPL Electric, LG&E and KU, see Note 10 for discussions regarding intercompany allocations associated with defined benefits.

14. Other Income (Expense) - net

(PPL)

The components of "Other Income (Expense) - net" for the years ended December 31, were:

	2024	2023	2022
Defined benefit plans - non-service credits (Note 10)	$ 42	$ 40	$ 47
Interest income	33	32	4
AFUDC - equity component	47	30	22
Charitable contributions	(5)	(5)	(14)
Talen litigation (a)	(2)	(124)	1
Miscellaneous	(1)	(13)	(6)
Other Income (Expense) - net	$ 114	$ (40)	$ 54

(a) PPL incurred legal expenses related to litigation associated with its former affiliate, Talen Montana, LLC, and certain affiliated entities (collectively, Talen), which was settled in December 2023.

(PPL Electric)

The components of "Other Income (Expense) - net" for the years ended December 31, were:

	2024	2023	2022
Defined benefit plans - non-service credits (Note 10)	$ 17	$ 20	$ 15
Interest income	8	8	3
AFUDC - equity component	23	16	16
Charitable contributions	(4)	(3)	(3)
Miscellaneous	1	(2)	(1)
Other Income (Expense) - net	$ 45	$ 39	$ 30

(LG&E)

The components of "Other Income (Expense) - net" for the years ended December 31, were:

	2024	2023	2022
Defined benefit plans - non-service credits (Note 10)	$ 3	$ —	$ 3
AFUDC - equity component	8	3	1
Charitable contributions	(1)	(1)	(1)
Miscellaneous	2	1	1
Other Income (Expense) - net	$ 12	$ 3	$ 4

(KU)

The components of "Other Income (Expense) - net" for the years ended December 31, were:

	2024	2023	2022
Defined benefit plans - non-service credits (Note 10)	$ 8	$ 6	$ 9
AFUDC - equity component	9	3	1
Charitable contributions	(1)	(1)	—
Miscellaneous	(1)	—	(2)
Other Income (Expense) - net	$ 15	$ 8	$ 8

15. Fair Value Measurements

(All Registrants)

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). A market approach (generally, data from market transactions), an income approach (generally, present value techniques and option-pricing models), and/or a cost approach (generally, replacement cost) are used to measure the fair value of an asset or liability, as appropriate. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk. The fair value of a group of financial assets and liabilities is measured on a net basis. See Note 1 for information on the levels in the fair value hierarchy.

Recurring Fair Value Measurements

The assets and liabilities measured at fair value were:

	December 31, 2024				December 31, 2023			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
PPL								
Assets								
Cash and cash equivalents	$ 306	$ 306	$ —	$ —	$ 331	$ 331	$ —	$ —
Restricted cash and cash equivalents (a)	33	33	—	—	51	51	—	—
Total Cash, Cash Equivalents and Restricted Cash (b)	339	339	—	—	382	382	—	—
Special use funds (a):								
Money market fund	1	1	—	—	1	1	—	—
Commingled debt fund measured at NAV (c)	10	—	—	—	9	—	—	—
Commingled equity fund measured at NAV (c)	8	—	—	—	8	—	—	—
Total special use funds	19	1	—	—	18	1	—	—
Price risk management assets (d):								
Gas contracts	9	—	4	5	1	—	1	—
Total assets	$ 367	$ 340	$ 4	$ 5	$ 401	$ 383	$ 1	$ —
Liabilities								
Price risk management liabilities (d):								
Interest rate swaps	$ 3	$ —	$ 3	$ —	$ 7	$ —	$ 7	$ —
Gas contracts	13	—	10	3	60	—	41	19
Total price risk management liabilities	$ 16	$ —	$ 13	$ 3	$ 67	$ —	$ 48	$ 19
PPL Electric								
Assets								
Cash and cash equivalents	$ 24	$ 24	$ —	$ —	$ 51	$ 51	$ —	$ —
Total assets	$ 24	$ 24	$ —	$ —	$ 51	$ 51	$ —	$ —
LG&E								
Assets								
Cash and cash equivalents	$ 8	$ 8	$ —	$ —	$ 18	$ 18	$ —	$ —
Restricted cash and cash equivalents (a)	16	16	—	—	26	26	—	—
Total Cash, Cash Equivalents and Restricted Cash (b)	24	24	—	—	44	44	—	—
Total assets	$ 24	$ 24	$ —	$ —	$ 44	$ 44	$ —	$ —
Liabilities								
Price risk management liabilities:								
Interest rate swaps	$ 3	$ —	$ 3	$ —	$ 7	$ —	$ 7	$ —
Total price risk management liabilities	$ 3	$ —	$ 3	$ —	$ 7	$ —	$ 7	$ —
KU								
Assets								
Cash and cash equivalents	$ 13	$ 13	$ —	$ —	$ 14	$ 14	$ —	$ —
Restricted cash and cash equivalents (a)	16	16	—	—	24	24	—	—
Total Cash, Cash Equivalents and Restricted Cash (b)	29	29	—	—	38	38	—	—
Total assets	$ 29	$ 29	$ —	$ —	$ 38	$ 38	$ —	$ —

(a) Current portion is included in "Other current assets" and noncurrent portion is included in "Other noncurrent assets" on the Balance Sheets.
(b) Total Cash, Cash Equivalents and Restricted Cash provides a reconciliation of these items reported within the Balance Sheets to the sum shown on the Statements of Cash Flows.
(c) In accordance with accounting guidance, certain investments that are measured at fair value using net asset value per share (NAV), or its equivalent, have not been classified in the fair value hierarchy. The fair value amounts presented in the table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the statement of financial position.
(d) Current portion is included in "Other current assets" and "Other current liabilities" and noncurrent portion is included in "Other noncurrent assets" "Other deferred credits and noncurrent liabilities" on the Balance Sheets.

A reconciliation of net assets classified as Level 3 for the year ended December 31 is as follows:

	Gas Contracts
2024	
Balance at beginning of period	$ (19)
Total unrealized gains (losses) recognized as Regulatory Assets/Regulatory Liabilities	2
Settlements	19
Balance at end of period	$ 2

Special Use Funds *(PPL)*

The special use funds are investments restricted for paying active union employee medical costs. In 2018, PPL received a favorable private letter ruling from the IRS permitting a transfer of excess funds from the PPL Bargaining Unit Retiree Health Plan VEBA to a new subaccount within the VEBA to be used to pay medical claims of active bargaining unit employees. In 2024, additional excess funds were removed from the PPL Bargaining Unit Retiree Health Plan VEBA and deposited in the existing subaccount within the VEBA to be used to pay medical claims of active bargaining unit employees. The funds are invested primarily in commingled debt and equity funds measured at NAV and are classified as investments in equity securities. Changes in the fair value of the funds are recorded to the Statements of Income.

Price Risk Management Assets/Liabilities

Interest Rate Swaps (PPL, LG&E and KU)

To manage interest rate risk, PPL, LG&E and KU use interest rate contracts such as forward-starting swaps, floating-to-fixed swaps and fixed-to-floating swaps. An income approach is used to measure the fair value of these contracts, utilizing readily observable inputs, such as forward interest rates (e.g., SOFR and government security rates), as well as inputs that may not be observable, such as credit valuation adjustments. In certain cases, market information cannot practicably be obtained to value credit risk and therefore internal models are relied upon. These models use projected probabilities of default and estimated recovery rates based on historical observances. When the credit valuation adjustment is significant to the overall valuation, the contracts are classified as Level 3.

Gas Contracts (PPL)

To manage gas commodity price risk associated with natural gas purchases, RIE utilizes over-the-counter (OTC) gas swaps contracts with pricing inputs obtained from the New York Mercantile Exchange (NYMEX) and the Intercontinental Exchange (ICE), except in cases where the ICE publishes seasonal averages or where there were no transactions within the last seven days. RIE may utilize discounting based on quoted interest rate curves, including consideration of non-performance risk, and may include a liquidity reserve calculated based on bid/ask spread. Substantially all of these price curves are observable in the marketplace throughout at least 95% of the remaining contractual quantity, or they could be constructed from market observable curves with correlation coefficients of 95% or higher. These contracts are classified as Level 2.

RIE also utilizes gas option and purchase and capacity transactions, which are valued based on internally developed models. Industry-standard valuation techniques, such as the Black-Scholes pricing model, are used for valuing such instruments. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is classified as Level 3. This includes derivative instruments valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility, and contract duration. Such instruments are classified as in Level 3 as the model inputs generally are not observable. RIE considers non-performance risk and liquidity risk in the valuation of derivative instruments classified as Level 2 and Level 3.
The significant unobservable inputs used in the fair value measurement of the gas derivative instruments are implied volatility and gas forward curves. A relative change in commodity price at various locations underlying the open positions can result in significantly different fair value estimates.

Financial Instruments Not Recorded at Fair Value *(All Registrants)*

The carrying amounts of long-term debt on the Balance Sheets and their estimated fair values are set forth below. Long-term debt is classified as Level 2. The effect of third-party credit enhancements is not included in the fair value measurement.

	December 31, 2024		December 31, 2023	
	Carrying Amount (a)	Fair Value	Carrying Amount (a)	Fair Value
PPL	$ 16,503	$ 15,562	$ 14,612	$ 14,031
PPL Electric	5,214	4,862	4,567	4,475
LG&E	2,471	2,295	2,469	2,369
KU	3,066	2,750	3,064	2,861

(a) Amounts are net of debt issuance costs.

The carrying amounts of other current financial instruments (except for long-term debt due within one year) approximate their fair values because of their short-term nature.

16. Derivative Instruments and Hedging Activities

Risk Management Objectives

(All Registrants)

PPL has a risk management policy approved by the Board of Directors to manage market risk associated with commodities, interest rates on debt issuances (including price, liquidity and volumetric risk) and credit risk (including non-performance risk and payment default risk). The Risk Management Committee, comprised of senior management and chaired by the Vice President-Financial Strategy and Chief Risk Officer, oversees the risk management function. Key risk control activities designed to ensure compliance with the risk policy and detailed programs include, but are not limited to, credit review and approval, validation of transactions, verification of risk and transaction limits, value-at-risk analyses (VaR, a statistical model that attempts to estimate the value of potential loss over a given holding period under normal market conditions at a given confidence level) and the coordination and reporting of the Enterprise Risk Management program.

Market Risk

Market risk includes the potential loss that may be incurred as a result of price changes associated with a particular financial or commodity instrument as well as market liquidity and volumetric risks. Forward contracts, futures contracts, options, swaps and structured transactions are utilized as part of risk management strategies to minimize unanticipated fluctuations in earnings caused by changes in commodity prices and interest rates. Many of these contracts meet the definition of a derivative. All derivatives are recognized on the Balance Sheets at their fair value, unless NPNS is elected.

The following summarizes the market risks that affect PPL and its subsidiaries.

Interest Rate Risk

- PPL and its subsidiaries are exposed to interest rate risk associated with forecasted fixed-rate and existing floating-rate debt issuances. PPL and LG&E utilize over-the-counter interest rate swaps to limit exposure to market fluctuations on floating-rate debt. PPL, LG&E and KU utilize forward starting interest rate swaps to hedge changes in benchmark interest rates, when appropriate, in connection with future debt issuance.
- PPL and its subsidiaries are exposed to interest rate risk associated with debt securities and derivatives held by defined benefit plans. This risk is significantly mitigated to the extent that the plans are sponsored at, or sponsored on behalf of, the regulated utilities due to the recovery methods in place.

Commodity Price Risk

PPL is exposed to commodity price risk through its subsidiaries as described below.

- PPL Electric is required to purchase electricity to fulfill its obligation as a PLR. Potential commodity price risk is mitigated through its PAPUC-approved cost recovery mechanism and full-requirement supply agreements to serve its PLR customers which transfer the risk to energy suppliers.
- LG&E's and KU's rates include certain mechanisms for fuel, fuel-related expenses and energy purchases. In addition, LG&E's rates include a mechanism for natural gas supply costs. These mechanisms generally provide for timely recovery of market price fluctuations associated with these costs.
- RIE utilizes derivative instruments pursuant to its RIPUC-approved plan to manage commodity price risk associated with its natural gas purchases. RIE's commodity price risk management strategy is to reduce fluctuations in firm gas sales prices to its customers. RIE's costs associated with derivatives instruments are recoverable through its RIPUC- approved cost recovery mechanisms. RIE is also required to purchase electricity to fulfill its obligation to provide Last Resort Service (LRS). Potential commodity price risk is mitigated through its RIPUC-approved cost recovery mechanisms and full requirements service agreements to serve LRS customers, which transfer the risk to energy suppliers. Additionally, RIE is
required to contract through long-term agreements for clean energy supply under the Rhode Island Renewable Energy Growth program and Long-term Clean Energy Standard. Potential commodity price risk is mitigated through its RIPUC-approved cost recovery mechanisms, which true-up cost differences between contract prices and market prices.

Volumetric Risk

Volumetric risk is the risk related to the changes in volume of retail sales due to weather, economic conditions or other factors. PPL is exposed to volumetric risk through its subsidiaries as described below:

- PPL Electric, LG&E and KU are exposed to volumetric risk on retail sales, mainly due to weather and other economic conditions for which there is limited mitigation between rate cases.
- RIE is exposed to volumetric risk, which is significantly mitigated by regulatory mechanisms. RIE's electric and gas distribution rates both have a revenue decoupling mechanism, which allows for annual adjustments to RIE's delivery rates.

Equity Securities Price Risk

- PPL and its subsidiaries are exposed to equity securities price risk associated with the fair value of the defined benefit plans' assets. This risk is significantly mitigated due to the recovery methods in place.
- PPL is exposed to equity securities price risk from future stock sales and/or purchases.

Credit Risk

Credit risk is the potential loss that may be incurred due to a counterparty's non-performance.

PPL is exposed to credit risk from "in-the-money" transactions with counterparties, as well as additional credit risk through certain of its subsidiaries, as discussed below.

In the event a supplier of PPL, PPL Electric, LG&E or KU defaults on its contractual obligation, those Registrants would be required to seek replacement power or replacement fuel in the market. In general, subject to regulatory review or other processes, appropriate incremental costs incurred by these entities would be recoverable from customers through applicable rate mechanisms, thereby mitigating the financial risk for these entities.

PPL and its subsidiaries have credit policies in place to manage credit risk, including the use of an established credit approval process, daily monitoring of counterparty positions and the use of master netting agreements or provisions. These agreements generally include credit mitigation provisions, such as margin, prepayment or collateral requirements. PPL and its subsidiaries may request additional credit assurance, in certain circumstances, in the event that the counterparties' credit ratings fall below investment grade, their tangible net worth falls below specified percentages or their exposures exceed an established credit limit.

Master Netting Arrangements *(PPL, LG&E and KU)*

Net derivative positions on the balance sheets are not offset against the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements.

PPL, LG&E and KU had no cash collateral posted or obligation to return cash collateral under master netting arrangements at December 31, 2024 and 2023.

See "Offsetting Derivative Instruments" below for a summary of derivative positions presented in the balance sheets where a right of setoff exists under these arrangements.

Interest Rate Risk

(All Registrants)

PPL and its subsidiaries issue debt to finance their operations, which exposes them to interest rate risk. A variety of financial derivative instruments are utilized to adjust the mix of fixed and floating interest rates in their debt portfolios, adjust the duration of the debt portfolios and lock in benchmark interest rates in anticipation of future financing, when appropriate. Risk limits under PPL's risk management program are designed to balance risk exposure to volatility in interest expense and changes in the fair value of the debt portfolio due to changes in benchmark interest rates. In addition, the interest rate risk of certain subsidiaries is potentially mitigated as a result of the existing regulatory framework or the timing of rate cases.

Cash Flow Hedges *(PPL)*

Interest rate risks include exposure to adverse interest rate movements for outstanding variable rate debt and for future anticipated financings. Financial interest rate swap contracts that qualify as cash flow hedges may be entered into to hedge floating interest rate risk associated with both existing and anticipated debt issuances. PPL had no such contracts at December 31, 2024.

Cash flow hedges are discontinued if it is no longer probable that the original forecasted transaction will occur by the end of the originally specified time period and any amounts previously recorded in AOCI are reclassified into earnings once it is determined that the hedged transaction is not probable of occurring.

For 2024, 2023 and 2022, PPL had no cash flow hedges reclassified into earnings associated with discontinued cash flow hedges.

At December 31, 2024, the amount of accumulated net unrecognized after-tax gains (losses) on qualifying derivatives expected to be reclassified into earnings during the next 12 months is insignificant. Amounts are reclassified as the hedged interest expense is recorded.

Economic Activity *(PPL and LG&E)*

LG&E enters into interest rate swap contracts that economically hedge interest payments. Because realized gains and losses from the swaps, including terminated swap contracts, are recoverable through regulated rates, any subsequent changes in fair value of these derivatives are included in regulatory assets or liabilities until they are realized as interest expense. Realized gains and losses are recognized in "Interest Expense" on the Statements of Income at the time the underlying hedged interest expense is recorded. At December 31, 2024, LG&E held contracts with a notional amount of $64 million that mature in 2033.

Commodity Price Risk *(PPL)*

Economic Activity

RIE enters into derivative contracts that economically hedge natural gas purchases. Realized gains and losses from the derivatives are recoverable through regulated rates, therefore subsequent changes in fair value are included in regulatory assets or liabilities until they are realized as purchased gas. Realized gains and losses are recognized in "Energy Purchases" on the Statements of Income upon settlement of the contracts. See Note 7 for amounts recorded in regulatory assets and regulatory liabilities at December 31, 2024. At December 31, 2024, RIE held contracts with notional volumes of 49 Bcf that range in maturity from 2025 through 2029.

Accounting and Reporting

(All Registrants)

All derivative instruments are recorded at fair value on the Balance Sheet as an asset or liability unless the NPNS is elected. NPNS contracts include certain full-requirement purchase contracts and other physical purchase contracts. Changes in the fair value of derivatives not designated as NPNS are recognized in earnings unless specific hedge accounting criteria are met and designated as such, except for the changes in fair values of LG&E's interest rate swaps that are recognized as regulatory assets or regulatory liabilities. See Note 7 for amounts recorded in regulatory assets and regulatory liabilities at December 31, 2024 and 2023.

See Note 1 for additional information on accounting policies related to derivative instruments.

(PPL)

The following table presents the fair value and location of derivative instruments recorded on the Balance Sheets:

	December 31, 2024				December 31, 2023			
	Derivatives designated as hedging instruments		Derivatives not designated as hedging instruments		Derivatives designated as hedging instruments		Derivatives not designated as hedging instruments	
	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities	Assets	Liabilities
Current:								
Price Risk Management Assets/Liabilities (a):								
Interest rate swaps (b)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 1
Gas contracts	—	—	7	10	—	—	1	51
Total current	—	—	7	10	—	—	1	52
Noncurrent:								
Price Risk Management Assets/Liabilities (a):								
Interest rate swaps (b)	—	—	—	3	—	—	—	6
Gas contracts	—	—	2	3	—	—	—	9
Total noncurrent	—	—	2	6	—	—	—	15
Total derivatives	$ —	$ —	$ 9	$ 16	$ —	$ —	$ 1	$ 67

(a) Current portion is included in "Other current assets" and "Other current liabilities" and noncurrent portion is included in "Other noncurrent assets" and "Other deferred credits and noncurrent liabilities" on the Balance Sheets.
(b) Excludes accrued interest, if applicable.

The following tables present the pre-tax effect of derivative instruments recognized in income, OCI or regulatory assets and regulatory liabilities:

Derivative Relationships	Derivative Gain (Loss) Recognized in OCI	Location of Gain (Loss) Recognized in Income on Derivative	Gain (Loss) Reclassified from AOCI into Income
2024			
Cash Flow Hedges:			
Interest rate swaps	$ —	Interest Expense	$ (3)
Total	$ —		$ (3)
2023			
Cash Flow Hedges:			
Interest rate swaps	$ —	Interest Expense	$ (3)
Total	$ —		$ (3)
2022			
Cash Flow Hedges:			
Interest rate swaps	$ —	Interest Expense	$ (3)
Total	$ —		$ (3)

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivative	2024	2023	2022
Interest rate swaps	Interest Expense	—	—	(2)
Gas contracts	Energy Purchases	(40)	(19)	41
	Other income (expense) - net	—	$ (1)	$ —
	Total	$ (40)	$ (20)	$ 39

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized as Regulatory Liabilities/Assets	2024	2023	2022
Gas contracts	Regulatory assets - current	$ 48	$ 9	$ 39
	Regulatory assets - noncurrent	7	(8)	—
Interest rate swaps	Regulatory assets - noncurrent	4	—	11
	Total	$ 59	$ 1	$ 50

The following table presents the effect of cash flow hedge activity on the Statement of Income for the year ended December 31, 2024:

	Location and Amount of Gain (Loss) Recognized in Income on Hedging Relationships
	Interest Expense
Total income and expense line items presented in the income statement in which the effect of cash flow hedges are recorded	$ 738
The effects of cash flow hedges:	
Gain (Loss) on cash flow hedging relationships:	
Interest rate swaps:	
Amount of gain (loss) reclassified from AOCI to income	(3)

The following table presents the effect of cash flow hedge activity on the Statement of Income for the year ended December 31, 2023:

	Location and Amount of Gain (Loss) Recognized in Income on Hedging Relationships
	Interest Expense
Total income and expense line items presented in the income statement in which the effect of cash flow hedges are recorded	$ 666
The effects of cash flow hedges:	
Gain (Loss) on cash flow hedging relationships:	
Interest rate swaps:	
Amount of gain (loss) reclassified from AOCI to income	(3)

The following table presents the effect of cash flow hedge activity on the Statement of Income for the year ended December 31, 2022:

	Location and Amount of Gain (Loss) Recognized in Income on Hedging Relationships
	Interest Expense
Total income and expense line items presented in the income statement in which the effect of cash flow hedges are recorded	$ 513
The effects of cash flow hedges:	
Gain (Loss) on cash flow hedging relationships:	
Interest rate swaps:	
Amount of gain (loss) reclassified from AOCI to income	(3)

(LG&E)

The following table presents the fair value and the location on the Balance Sheets of derivatives not designated as hedging instruments:

	December 31, 2024		December 31, 2023	
	Assets	Liabilities	Assets	Liabilities
Current:				
Price Risk Management Assets/Liabilities:				
Interest rate swaps	$ —	$ —	$ —	$ 1
Total current	—	—	—	1
Noncurrent:				
Price Risk Management Assets/Liabilities:				
Interest rate swaps	—	3	—	6
Total noncurrent	—	3	—	6
Total derivatives	$ —	$ 3	$ —	$ 7

The following tables present the pre-tax effect of derivatives not designated as cash flow hedges that are recognized in income or regulatory assets:

Derivative Instruments	Location of Gain (Loss)	2024	2023	2022
Interest rate swaps	Interest Expense	$ —	$ —	$ (2)

Derivative Instruments	Location of Gain (Loss)	2024	2023	2022
Interest rate swaps	Regulatory assets - noncurrent	$ 4	$ —	$ 11

(PPL, LG&E and KU)

Offsetting Derivative Instruments

PPL, LG&E and KU or certain of their subsidiaries have master netting arrangements in place and also enter into agreements pursuant to which they purchase or sell certain energy and other products. Under the agreements, upon termination of the agreement as a result of a default or other termination event, the non-defaulting party typically would have a right to set off amounts owed under the agreement against any other obligations arising between the two parties (whether under the agreement or not), whether matured or contingent and irrespective of the currency, place of payment or place of booking of the obligation.

PPL, LG&E and KU have elected not to offset derivative assets and liabilities and not to offset net derivative positions against the right to reclaim cash collateral pledged (an asset) or the obligation to return cash collateral received (a liability) under derivatives agreements. The table below summarizes the derivative positions presented in the balance sheets where a right of setoff exists under these arrangements and related cash collateral received or pledged.

	Assets				Liabilities			
		Eligible for Offset				Eligible for Offset		
	Gross	Derivative Instruments	Cash Collateral Received	Net	Gross	Derivative Instruments	Cash Collateral Pledged	Net
December 31, 2024								
Derivatives								
PPL	$ 9	$ 5	$ —	$ 4	$ 16	$ 5	$ —	$ 11
LG&E	—	—	—	—	3	—	—	3
December 31, 2023								
Derivatives								
PPL	$ 1	$ —	$ —	$ 1	$ 67	$ —	$ —	$ 67
LG&E	—	—	—	—	7	—	—	7

Credit Risk-Related Contingent Features

Certain derivative contracts contain credit risk-related contingent features which, when in a net liability position, would permit the counterparties to require the transfer of additional collateral upon a decrease in the credit ratings of PPL, LG&E and KU or certain of their subsidiaries. Most of these features would require the transfer of additional collateral or permit the counterparty to terminate the contract if the applicable credit rating were to fall below investment grade. Some of these features also would allow the counterparty to require additional collateral upon each downgrade in credit rating at levels that remain above investment grade. In either case, if the applicable credit rating were to fall below investment grade, and assuming no assignment to an investment grade affiliate were allowed, most of these credit contingent features require either immediate payment of the net liability as a termination payment or immediate and ongoing full collateralization on derivative instruments in net liability positions.

Additionally, certain derivative contracts contain credit risk-related contingent features that require adequate assurance of performance be provided if the other party has reasonable concerns regarding the performance of PPL's, LG&E's and KU's obligations under the contracts. A counterparty demanding adequate assurance could require a transfer of additional collateral or other security, including letters of credit, cash and guarantees from a creditworthy entity. This would typically involve negotiations among the parties. However, amounts disclosed below would represent assumed immediate payment or immediate and ongoing full collateralization for derivative instruments in net liability positions with "adequate assurance" features.
(PPL)

At December 31, 2024, derivative contracts in a net liability position that contain credit risk-related contingent features was $3 million. The aggregate fair value of additional collateral requirements in the event of a credit downgrade below investment grade was $4 million.

17. Goodwill and Other Intangible Assets

Goodwill

(PPL)

The changes in the carrying amount of goodwill by segment were:

	Kentucky Regulated		Rhode Island Regulated		Corporate and Other		Total	
	2024	2023	2024	2023	2024	2023	2024	2023
Balance at beginning of period (a)	$ 662	$ 662	$ 725	$ 725	$ 860	$ 861	$ 2,247	$ 2,248
Goodwill recognized during the period (b)	—	—	—	—	—	(1)	—	(1)
Total	$ 662	$ 662	$ 725	$ 725	$ 860	$ 860	$ 2,247	$ 2,247

(a) There were no accumulated impairment losses related to goodwill.
(b) Recognized as a result of purchase price allocation adjustments related to the acquisition of RIE. See Note 9 for additional information.

Other Intangible Assets

(PPL)

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2024		December 31, 2023	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Contracts (a)	$ 125	$ 116	$ 125	$ 107
Renewable Energy Credits	20	—	15	—
Land rights and easements	432	147	411	143
Licenses and other	2	—	2	—
Total subject to amortization	579	263	553	250
Not subject to amortization due to indefinite life:				
Land rights and easements	18	—	18	—
Total not subject to amortization due to indefinite life	18	—	18	—
Total	$ 597	$ 263	$ 571	$ 250

(a) Gross carrying amount in 2024 and 2023 includes the fair value at the acquisition date of the OVEC power purchase contract with terms favorable to market recognized as a result of the 2010 acquisition of LKE by PPL.

Current intangible assets are included in "Other current assets" and long-term intangible assets are included in "Other intangibles" on the Balance Sheets.

Amortization expense was as follows:

	2024	2023	2022
Intangible assets with no regulatory offset	$ 5	$ 5	$ 5
Intangible assets with regulatory offset	8	9	9
Total	$ 13	$ 14	$ 14

Amortization expense for each of the next five years is estimated to be:

	2025	2026	2027	2028	2029
Intangible assets with no regulatory offset	$ 4	$ 4	$ 4	$ 4	$ 4
Intangible assets with regulatory offset	8	2	—	—	—
Total	$ 12	$ 6	$ 4	$ 4	$ 4

(PPL Electric)

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2024		December 31, 2023	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Land rights and easements	$ 396	$ 141	$ 389	$ 138
Licenses and other	2	1	2	1
Total subject to amortization	398	142	391	139
Not subject to amortization due to indefinite life:				
Land rights and easements	18	—	17	—
Total	$ 416	$ 142	$ 408	$ 139

Intangible assets are shown as "Intangibles" on the Balance Sheets.

Amortization expense was as follows:

	2024	2023	2022
Intangible assets with no regulatory offset	$ 4	$ 4	$ 4

Amortization expense for each of the next five years is estimated to be:

	2025	2026	2027	2028	2029
Intangible assets with no regulatory offset	$ 4	$ 4	$ 4	$ 4	$ 4

(LG&E)

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2024		December 31, 2023	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Land rights and easements	$ 7	$ 2	$ 7	$ 2
OVEC power purchase agreement (a)	86	79	86	73
Total subject to amortization	$ 93	$ 81	$ 93	$ 75

(a) Gross carrying amount represents the fair value at the acquisition date of the OVEC power purchase contract recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to this contract, which is being amortized over the same period as the intangible asset, eliminating any income statement impact. See Note 7 for additional information.

Long-term intangible assets are presented as "Other intangibles" on the Balance Sheets.
Amortization expense was as follows:

	2024	2023	2022
Intangible assets with regulatory offset	$ 6	$ 6	$ 6

Amortization expense for each of the next five years is estimated to be:

	2025	2026	2027	2028	2029
Intangible assets with regulatory offset	$ 6	$ 1	$ —	$ —	$ —

(KU)

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2024		December 31, 2023	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Land rights and easements	$ 29	$ 4	$ 17	$ 4
OVEC power purchase agreement (a)	39	36	39	33
Total subject to amortization	$ 68	$ 40	$ 56	$ 37

(a) Gross carrying amount represents the fair value at the acquisition date of the OVEC power purchase contract recognized as a result of the 2010 acquisition by PPL. An offsetting regulatory liability was recorded related to this contract, which is being amortized over the same period as the intangible asset, eliminating any income statement impact. See Note 7 for additional information.

Long-term intangible assets are presented as "Other intangibles" on the Balance Sheets.

Amortization expense was as follows:

	2024	2023	2022
Intangible assets with regulatory offset	2	3	3

Amortization expense for each of the next five years is estimated to be:

	2025	2026	2027	2028	2029
Intangible assets with regulatory offset	$ 2	$ 1	$ —	$ —	$ —

18. Asset Retirement Obligations

(PPL and PPL Electric)

PPL Electric has identified legal retirement obligations for the retirement of certain transmission assets that could not be reasonably estimated due to indeterminable settlement dates. These assets are located on rights-of-way that allow the grantor to require PPL Electric to relocate or remove the assets. Since this option is at the discretion of the grantor of the right-of-way, PPL Electric is unable to determine when these events may occur.

(PPL, LG&E and KU)

PPL's, LG&E's and KU's ARO liabilities are primarily related to CCR closure costs. See Note 12 for information on the CCR rule. LG&E and RIE also have AROs related to natural gas mains and wells. LG&E's and KU's transmission and distribution lines largely operate under perpetual property easement agreements, which do not generally require restoration upon removal of the property. Therefore, no material AROs are recorded for transmission and distribution assets. For LG&E, KU, and RIE , all ARO accretion and depreciation expenses are reclassified as a regulatory asset or regulatory liability. ARO regulatory assets associated with certain CCR projects are amortized to expense in accordance with regulatory approvals. For other AROs, deferred accretion and depreciation expense is recovered through cost of removal.

The changes in the carrying amounts of AROs were as follows:

	PPL		LG&E		KU	
	2024	2023	2024	2023	2024	2023
ARO at beginning of period	$ 158	$ 177	$ 85	$ 86	$ 66	$ 82
Accretion	8	9	4	4	4	5
Obligations incurred	9	2	3	1	6	1
Changes in estimated timing or cost	4	15	3	11	1	6
Obligations settled	(24)	(39)	(11)	(11)	(13)	(28)
Other	2	(6)	—	(6)		—
ARO at end of period	$ 157	$ 158	$ 84	$ 85	$ 64	$ 66

19. Accumulated Other Comprehensive Income (Loss)

(PPL)

The after-tax changes in AOCI by component for the years ended December 31 were as follows:

	Foreign currency translation adjustments	Unrealized gains (losses) on qualifying derivatives	Equity investees' AOCI	Defined benefit plans: Prior service costs	Defined benefit plans: Actuarial gain (loss)	Total
PPL						
December 31, 2021	$ —	$ 1	$ —	$ (6)	$ (152)	$ (157)
Amounts arising during the year	—	—	2	(1)	11	12
Reclassifications from AOCI	—	2	—	2	17	21
Net OCI during the year	—	2	2	1	28	33
December 31, 2022	$ —	$ 3	$ 2	$ (5)	$ (124)	$ (124)
Amounts arising during the year	—	—	1	—	(41)	(40)
Reclassifications from AOCI	—	3	—	1	(3)	1
Net OCI during the year	—	3	1	1	(44)	(39)
December 31, 2023	$ —	$ 6	$ 3	$ (4)	$ (168)	$ (163)
Amounts arising during the year	—	—	1	—	(22)	(21)
Reclassifications from AOCI	—	3	—	1	(4)	—
Net OCI during the year	—	3	1	1	(26)	(21)
December 31, 2024	$ —	$ 9	$ 4	$ (3)	$ (194)	$ (184)

The following table presents PPL's gains (losses) and related income taxes for reclassifications from AOCI for the years ended December 31, 2024, 2023 and 2022. The defined benefit plan components of AOCI are not reflected in their entirety in the statement of income; rather, they are included in the computation of net periodic defined benefit costs (credits) and subject to capitalization. See Note 10 for additional information.

	PPL			
Details about AOCI	2024	2023	2022	Affected Line Item on the Statements of Income
Qualifying derivatives				
Interest rate swaps	$ (3)	$ (3)	$ (3)	Interest Expense
Total Pre-tax	(3)	(3)	(3)	
Income Taxes	—	—	1	
Total After-tax	(3)	(3)	(2)	
Defined benefit plans				
Prior service costs	(1)	(2)	(3)	
Net actuarial loss	4	3	(24)	
Total Pre-tax	3	1	(27)	
Income Taxes	—	1	8	
Total After-tax	3	2	(19)	
Total reclassifications during the year	$ —	$ (1)	$ (21)	

20. New Accounting Guidance Pending Adoption

(All Registrants)

Improvements to Income Tax Disclosures

In December 2023, the FASB issued guidance which requires public business entities to provide additional income tax disclosures including a disaggregated rate reconciliation as well as information on income taxes paid.

For public business entities, this guidance will be applied on a prospective basis. Retrospective application is permitted. This guidance will be effective for annual periods beginning after December 15, 2024. Early adoption is permitted for annual financial statements that have not yet been issued or made available for issuance.

The Registrants are currently assessing the impact of adopting this guidance.

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued guidance which requires public business entities to provide in the notes to financial statements specified information about certain costs and expenses. This includes the disclosure of amounts of (a) purchases of inventory, (b) employee compensation, (c) depreciation, (d) intangible asset amortization, and (e) depreciation, depletion, and amortization recognized as part of oil and gas-producing activities (DD&A) included in each relevant income statement expense caption. A relevant expense caption is an expense caption included on the face of the income statement within continuing operations that contains any of the specified expense categories (a)-(e). A qualitative description of the amounts remaining in relevant expense captions that are not separately disaggregated must also be disclosed. Additionally, public business entities must disclose the total amount of selling expenses and, in annual reporting periods, the entity's definition of selling expenses.

For public business entities, this guidance will be applied on a prospective basis. Retrospective application is permitted. This guidance will be effective for annual periods beginning after December 15, 2026, and interim periods reporting periods beginning after December 15, 2027. Early adoption is permitted.

The Registrants are currently assessing the impact of adopting this guidance.

21. Notes to Statement of Cash Flows

Supplemental disclosures of cash flow information:

	KU		LG&E	
	December 31, 2024	December 31, 2023	December 31,2024	December 31,2023
Cash paid (received) during the period for:				
Income taxes	$ 102	$ 78	$ 73	$ 84
Interest	135	125	101	93
Significant noncash transactions:				
Accrued expenditures for property, plant, and equipment	74	38	64	30

22. Subsequent Events

CPCN

On February 28, 2025, LG&E and KU filed an application with the KPSC regarding certain future plans for new generation and related matters.

The Companies submitted a joint application to the KPSC for approval of certain certificates of convenience and necessity, site compatibility certificates, and accounting treatment, where applicable, relating to a number of generation-related plans or projects that generally are expected to become operational or established within the next six years. The aggregate projected capital expenditures associated with these proposals are expected to be approximately $3.7 billion over the 2025 to 2031 period. The application includes proposals:

- to build a 645MW natural gas combined cycle NGCC generation unit at KU's E.W. Brown station,
- to build a 645MW NGCC generation unit at LG&E's Mill Creek station,
- to build a four-hour 400MW (1,600MWh total) battery storage facility ("BESS") at LG&E's Cane Run station, and
- to build a selective catalytic reduction ("SCR") environmental facility for an existing coal generation unit at KU's Ghent station.

The new NGCC units are currently anticipated to be wholly owned by LG&E and the BESS unit jointly owned by LG&E and KU in respective 32% and 68% shares, with actual project costs allocated consistent with LG&E's and KU's ultimate ownership shares and existing shared dispatch, cost allocation, tariff or other frameworks.

The filing also notes projected in service dates for the projects, including the E.W. Brown NGCC in 2030, the Mill Creek NGCC in 2031, the Cane Run BESS in 2028 and the Ghent SCR in 2028.

LG&E and KU cannot predict the outcome of the proceeding. LG&E and KU anticipate a ruling from the KPSC during the fourth quarter of 2025.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year									
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)								312,087,959	312,087,959
5	Balance of Account 219 at End of Preceding Quarter/Year									
6	Balance of Account 219 at Beginning of Current Year									
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)								355,591,111	355,591,111
10	Balance of Account 219 at End of Current Quarter/Year									

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	11,063,500,643	11,063,500,643					
4	Property Under Capital Leases	[(a)]24,019,037	[(b)]24,019,037					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	804,972,176	804,972,176					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	11,892,491,856	11,892,491,856					
9	Leased to Others							
10	Held for Future Use	18,268,633	18,268,633					
11	Construction Work in Progress	571,822,449	571,822,449					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	12,482,582,938	12,482,582,938					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	4,549,792,969	4,549,792,969					
15	Net Utility Plant (13 less 14)	7,932,789,969	7,932,789,969					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	4,493,873,502	4,493,873,502					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	55,919,467	55,919,467					
22	Total in Service (18 thru 21)	4,549,792,969	4,549,792,969					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
32	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,549,792,969	4,549,792,969					
Page 200-201								

FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases
Amounts represent operating leases recorded in accordance with ASC 842 - Leases. KU has elected to record operating lease right-of-use assets using the existing FERC balance sheet accounts for capital leases as permitted in Docket No. AI19-1-000.
(b) Concept: UtilityPlantInServicePropertyUnderCapitalLeases
Amounts represent operating leases recorded in accordance with ASC 842 - Leases. KU has elected to record operating lease right-of-use assets using the existing FERC balance sheet accounts for capital leases as permitted in Docket No. AI19-1-000.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction					
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)					
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)					
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)					
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization	44,456					44,456
3	(302) Franchise and Consents	55,919					55,919
4	(303) Miscellaneous Intangible Plant	88,904,409	5,908,561	21,395,518			73,417,452
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	89,004,784	5,908,561	21,395,518			73,517,827
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	26,828,421					26,828,421
9	(311) Structures and Improvements	483,033,638	2,138,564	403,082			484,769,120
10	(312) Boiler Plant Equipment	4,331,457,920	176,222,103	45,545,514			4,462,134,509
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	380,920,313	11,011,253	2,102,266			389,829,300
13	(315) Accessory Electric Equipment	262,943,302	3,771,831	413,232			266,301,901
14	(316) Misc. Power Plant Equipment	45,863,367	1,849,417	491,963			47,220,821
15	(317) Asset Retirement Costs for Steam Production	140,236,677	7,927,621	57,402,418	(880,885)		89,880,995
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	5,671,283,638	202,920,789	106,358,475	(880,885)		5,766,965,067
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						
20	(322) Reactor Plant Equipment						
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	855,637					855,637
28	(331) Structures and Improvements	4,275,193					4,275,193
29	(332) Reservoirs, Dams, and Waterways	26,779,582					26,779,582
30	(333) Water Wheels, Turbines, and Generators	14,505,210	800,756	608,485			14,697,481
31	(334) Accessory Electric Equipment	1,416,846					1,416,846
32	(335) Misc. Power Plant Equipment	376,930	307,002				683,932
33	(336) Roads, Railroads, and Bridges	190,033					190,033
34	(337) Asset Retirement Costs for Hydraulic Production	863,913					863,913
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	49,263,344	1,107,758	608,485			49,762,617
36	D. Other Production Plant						
37	(340) Land and Land Rights	894,513					894,513
38	(341) Structures and Improvements	91,514,096	429,056	3,864			91,939,288
39	(342) Fuel Holders, Products, and Accessories	84,995,548	299,187	24,795			85,269,940
40	(343) Prime Movers	721,727,319	41,605,644	6,661,908			756,671,055
41	(344) Generators	140,055,972	1,892,773	961,288			140,987,457
42	(345) Accessory Electric Equipment	77,397,299	187,349	14,142			77,570,506
43	(346) Misc. Power Plant Equipment	9,953,561	443,476	5,490			10,391,547
44	(347) Asset Retirement Costs for Other Production	620,114			(132,984)		487,130
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,127,158,422	44,857,485	7,671,487	(132,984)		1,164,211,436
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	6,847,705,404	248,886,032	114,638,447	(1,013,869)		6,980,939,120
47	3. Transmission Plant						
48	(350) Land and Land Rights	33,658,974	12,323,408				45,982,382
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	48,337,287	16,815,984	28,695			65,124,576
50	(353) Station Equipment	463,362,241	54,751,925	370,252			517,743,914
51	(354) Towers and Fixtures	84,959,554	6,269,188				91,228,742
52	(355) Poles and Fixtures	714,419,485	86,380,434	1,056,119			799,743,800
53	(356) Overhead Conductors and Devices	328,983,551	(14,105,696)	1,741,526			313,136,329
54	(357) Underground Conduit	385,375					385,375
55	(358) Underground Conductors and Devices	9,680,095	618,621	14,143			10,284,573
56	(359) Roads and Trails						
57	(359.1) Asset Retirement Costs for Transmission Plant	790,181		49,602			740,579
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,684,576,743	163,053,864	3,260,337			1,844,370,270
59	4. Distribution Plant						
60	(360) Land and Land Rights	9,193,151		37,019			9,156,132

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
61	(361) Structures and Improvements	32,670,361	2,428,179	22,450			35,076,090
62	(362) Station Equipment	340,949,112	87,506,914	791,702			427,664,324
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	525,326,786	47,302,254	4,084,072			568,544,968
65	(365) Overhead Conductors and Devices	531,092,548	67,406,768	11,129,152			587,370,164
66	(366) Underground Conduit	2,557,897	7,028	20,694			2,544,231
67	(367) Underground Conductors and Devices	254,200,879	17,843,329	542,590			271,501,618
68	(368) Line Transformers	369,523,674	27,485,140	929,231			396,079,583
69	(369) Services	163,883,474	12,611,498	231,596			176,263,376
70	(370) Meters	62,335,975	634,160	23,852,815			39,117,320
71	(371) Installations on Customer Premises	177,757	20,582				198,339
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	168,077,077	16,128,533	4,020,025			180,185,585
74	(374) Asset Retirement Costs for Distribution Plant	538,598					538,598
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,460,527,289	279,374,385	45,661,346			2,694,240,328
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	7,130,773	536,474	231,673			7,435,574
87	(390) Structures and Improvements	111,635,679	9,624,255	4,279,149		6,723	116,987,508
88	(391) Office Furniture and Equipment	44,725,366	1,897,341	9,805,759		(415,386)	36,401,562
89	(392) Transportation Equipment	8,706,536	64,027	20,795			8,749,768
90	(393) Stores Equipment	732,288	91,990	15,682		(6,723)	801,873
91	(394) Tools, Shop and Garage Equipment	17,587,390	1,067,759	458,289			18,196,860
92	(395) Laboratory Equipment						
93	(396) Power Operated Equipment	8,321,835	536,179				8,858,014
94	(397) Communication Equipment	88,476,871	250,106	11,272,380		415,386	77,869,983
95	(398) Miscellaneous Equipment	104,132					104,132
96	SUBTOTAL (Enter Total of lines 86 thru 95)	287,420,870	14,068,131	26,083,727			275,405,274
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	287,420,870	14,068,131	26,083,727			275,405,274
100	TOTAL (Accounts 101 and 106)	11,369,235,090	711,290,973	211,039,375	(1,013,869)		11,868,472,819
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	11,369,235,090	711,290,973	211,039,375	(1,013,869)		[a]11,868,472,819

Page 204-207

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: ElectricPlantInService
Excludes $24,019,037 of Property Under Operating Leases recorded related to adoption and implementation of ASC 842 – Leases.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL					

Page 213

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Pennington Gap Substation #2	08/01/2013	12/31/2028	324,088
3	Land at Green River Facility	11/01/2014	12/31/2029	309,541
4	Georgetown Pavillion Substation	06/01/2022	12/31/2026	696,155
5	Carrollton Operations Center	02/01/2023	12/31/2027	442,894
6	Mercer County Solar Field	06/30/2023	12/31/2025	16,117,971
7	Other Items less than $250K			377,984
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				

45				
46				
47	TOTAL			18,268,633

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	STEAM PRODUCTION MAJOR	
2	EFFLUENT LIMITATIONS GUIDELINES GHENT ENVIRONMENTAL COST RECOVERY	68,004,417
3	GHENT LANDFILL ROAD COAL COMBUSTION RESIDUALS	2,352,570
4	GHENT 2 IDENTIFICATION FAN VARIABLE FREQUENCY DRIVE UPGRADE	2,289,273
5	GHENT LIMESTONE UNLOADER REPLACEMENT	1,956,381
6	GHENT EFFLUENT LIMITATIONS GUIDELINES BOTTOM ASH UNIT 4	1,951,383
7	TRIMBLE COUNTY COAL COMBUSTION RESIDUALS LANDFILL	1,660,940
8	EFFLUENT LIMITATIONS GUIDELINES TRIMBLE COUNTY ENVIRONMENTAL COST RECOVERY	1,313,446
9	GHENT 1 SOOT BLOWING AIR COMPRESSOR REPLACEMENT	1,130,535
10	GHENT COAL YARD CONTROL RELAY UPGRADE	1,075,592
11	BROWN 3 MILL CRANE REPLACEMENT	1,024,532
12	STEAM PRODUCTION MINOR	14,755,345
13	HYDRAULIC POWER MINOR	425,523
14	OTHER PRODUCTION MAJOR	
15	MILL CREEK UNIT 5 NATURAL GAS COMBINED CYCLE	164,010,568
16	MERCER COUNTY SOLAR	1,512,396
17	OTHER PRODUCTION MINOR	5,039,670
18	TRANSMISSION MAJOR	
19	POLE REPLACEMENT DORCHESTER POCKET NORTH	18,165,210
20	POLE BREAKER REPLACEMENT MORGANFIELD	6,330,722
21	PRIORITY REPLACEMENT TRANSMISSION LINES	4,601,224
22	ASHWOOD SOLAR NETWORK SUBSTATION UPGRADE	4,505,037
23	POLE REPLACEMENT LYNCH IMBODEN	4,195,188
24	POLE REPLACEMENT MORGANFIELD GREEN RIVER	4,103,497
25	1156 REDUNDANT RELAY BROWN COMBUSTION TURBINE	3,099,831
26	345/138KV 450 MVA SPARE TRANSFORMER	3,051,738
27	POLE REPLACEMENT IMBODEN GORGE DORCHESTER	2,751,767
28	POLE REPLACEMENT DORCHESTER SAINT PAUL	1,899,094
29	PINEVILLE ROCKY BRANCH RIGHT OF WAY	1,601,826
30	TRANSMISSION LINES MATTING	1,468,017
31	POLE REPLACEMENT DORCHESTER DIXIANA	1,343,447

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
32	RELIABILITY NEW LINE BIG STONE GAP	1,278,002
33	PROACTIVE CONTROL HOUSE LAKE REBA POLE BREAKER REPLACEMENT	1,111,500
34	TRANSMISSION SUBSTATION EQUIPMENT FAILURES	1,067,088
35	TRANSMISSION MINOR	23,466,693
36	DISTRIBUTION MAJOR	
37	ADVANCED METERING INFRASTRUCTURE METERS	86,715,707
38	HARRODSBURG SUBSTATION TRANSFORMER CONTINGENCY PROJECT	5,165,071
39	ADVANCED METERING INFRASTRUCTURE METERS VIRGINIA	3,622,271
40	SCADA VOLTAGE CONTROL LINES	2,094,672
41	SHELBYVILLE INDUSTRIAL LAND	1,821,974
42	PURCHASE OF NEW TRANSFORMERS	1,084,270
43	OAK HILL 3814 CONTROL HOUSE	1,046,120
44	DISTRIBUTION MINOR	23,346,530
45	GENERAL PLANT MAJOR	
46	CUSTOMER SERVICE ADVANCED METERING INFRASTRUCTURE METER DEPLOYMENT	19,104,544
47	CUSTOMER SERVICE ADVANCED METERING INFRASTRUCTURE NETWORK COMMUNICATION	13,053,963
48	CUSTOMER SERVICE ADVANCED METERING INFRASTRUCTURE METER CASH	8,912,771
49	CUSTOMER SERVICE ADVANCED METERING INFRASTRUCTURE SWITCH	8,734,845
50	LIMESTONE / LOUDON RELOCATION TO LISLE AVENUE	7,718,074
51	BROADWAY OFFICE COMPLEX RENOVATIONS	3,460,796
52	ADVANCED METER INFRASTRUCTURE CUSTOMER ENGAGEMENT	2,026,345
53	ADVANCED METER INFRASTRUCTURE INTEGRATION	1,743,381
54	PROACTIVE CUSTOMER NOTIFICATION	1,688,888
55	SERVICE NOW IMPROVEMENT	1,686,884
56	PENNINGTON GAP STORE ROOM RELOCATION	1,637,815
57	WINDOWS AUTOPILOT, AZURE VIRTUAL DESKTOP, CYBERARK, AND WINDOWS UPGRADE	1,602,618
58	CUSTOMER SERVICE ADVANCED METERING INFRASTRUCTURE INFORMATION TECHNOLOGY SYSTEMS	1,421,206
59	STANDARDIZED ON PREMISE DATA CENTER HARDWARE	1,359,878
60	REPLACEMENT OF MICROWAVE COMMUNICATION PATHS	1,224,322
61	GENERAL PLANT MINOR	18,686,072
62	RESEARCH, DEVELOPMENT, AND DEMONSTRATING MINOR	320,980
43	Total	571,822,449

Page 216

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	4,326,850,863	4,326,850,863		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	368,952,386	368,952,386		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	486,537	486,537		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):				
9.2	Fuel Stock	1,673,257	1,673,257		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	371,112,180	371,112,180		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(132,191,837)	(132,191,837)		
13	Cost of Removal	(31,764,340)	(31,764,340)		
14	Salvage (Credit)	2,800,707	2,800,707		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(161,155,470)	(161,155,470)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Accrual for Depreciation on Asset Retirement Costs - (Other Regulatory Assets FERC 182.3)	12,376,485	12,376,485		
17.2	Customer Payments Related to Construction Projects	2,141,464	2,141,464		
18	Book Cost or Asset Retirement Costs Retired	(57,452,020)	(57,452,020)		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,493,873,502	4,493,873,502		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,672,957,250	2,672,957,250		
21	Nuclear Production				
22	Hydraulic Production-Conventional	18,391,596	18,391,596		
23	Hydraulic Production-Pumped Storage				
24	Other Production	525,484,333	525,484,333		
25	Transmission	466,032,432	466,032,432		

26	Distribution	724,286,987	724,286,987		
27	Regional Transmission and Market Operation				
28	General	86,720,904	86,720,904		
29	TOTAL (Enter Total of lines 20 thru 28)	4,493,873,502	4,493,873,502		

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1	Ohio Valley Electric Corporation							
2	OVEC Common Stock - 250 shares - 11/18/52 - Capital Stock	11/18/1952		25,000			25,000	
3	OVEC Common Stock - 250 shares - 1/14/53 - Capital Stock	01/14/1953		25,000			25,000	
4	OVEC Common Stock - 250 shares - 3/4/53 - Capital Stock	03/04/1953		25,000			25,000	
5	OVEC Common Stock - 250 shares - 4/15/53 - Capital Stock	04/15/1953		25,000			25,000	
6	OVEC Common Stock - 250 shares - 5/20/53 - Capital Stock	05/20/1953		25,000			25,000	
7	OVEC Common Stock - 250 shares - 6/22/53 - Capital Stock	06/22/1953		25,000			25,000	
8	OVEC Common Stock - 500 shares - 7/15/53 - Capital Stock	07/15/1953		50,000			50,000	
9	OVEC Common Stock - 500 shares - 7/31/1953 - Capital Stock	07/31/1953		50,000			50,000	
10	Electric Energy Inc.							
11	EEI Common Stock - 3,500 shares - 3/6/51 - Capital Stock	03/06/1951						
12	EEI Common Stock - 2,700 shares - 8/3/53 - Capital Stock	08/03/1953						
13	EEI Common Stock - 6,200 shares - 12/30/58 - Capital Stock	12/30/1958						
42	Total Cost of Account 123.1 $250,000.00		Total	250,000			250,000	

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	94,060,591	88,991,273	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	57,091,352	63,854,457	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	14,547,442	9,704,622	Electric
8	Transmission Plant (Estimated)	10,262,626	4,589,514	Electric
9	Distribution Plant (Estimated)	6,914,019	4,931,228	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	88,815,439	83,079,821	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	[a]1,928,335	[b]987,675	Electric
17				
18				
19				
20	TOTAL Materials and Supplies	184,804,365	173,058,769	

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: StoresExpenseUndistributed

Balance at Beginning of Year	$	1,499,886
Total Debits		6,622,362
Total Credits		(6,193,913)
Balance at End of Year	$	1,928,335

(b) Concept: StoresExpenseUndistributed

Balance at Beginning of Year	$	1,928,335
Total Debits		6,491,430
Total Credits		(7,432,090)
Balance at End of Year	$	987,675

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	972,295	118,250	92,861		77,535		77,535		2,093,445		3,313,671	118,250
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	12,899	1,385									12,899	1,385
19	Other:												
20	Allowances Used												
20.1	Allowances Used	(3)										(3)	
21	Cost of Sales/Transfers:												
22													
23													
24													

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
25													
26													
27													
28	Total												
29	Balance-End of Year	959,399	116,865	92,861		77,535		77,535		2,093,445		3,300,775	116,865
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	1,107		1,107		1,107		1,107		49,793		54,221	
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales	1,107								1,107		2,214	
40	Balance-End of Year			1,107		1,107		1,107		48,686		52,007	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)	1,107	22							1,107	22	2,214	44
45	Gains		22								22		44
46	Losses												

Page 228(ab)-229(ab)a

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	75,352		14,637								89,989	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	6,390										6,390	
19	Other:												
20	Allowances Used												
20.1	Allowances Used	45										45	
21	Cost of Sales/Transfers:												
22													
23													
24													

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
25													
26													
27													
28	Total												
29	Balance-End of Year	68,917		14,637								83,554	
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Page 228(ab)-229(ab)b

Page 228(ab)-229(ab)b

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	System Impact Study(TS)				
3	Madisonville West			1,565	561.6
4	Affected S.S MISO	20,375	561.6	20,375	561.6
5	Shelby Logistics-SIS	2,728	561.6	3,691	561.6
6	LKE Pavilion-SIS	249	561.6	337	561.6
7	KMPA Paducah LD	9,193	561.6	1,613	561.6
8	DNR Mercer SLR	1,324	561.6	1,792	561.6
9	DNR Brown BESS	83	561.6	112	561.6
10	AFSS PJM TC1+FT	28,267	561.6		
11	Facilities Study (FS)				
12	LKE Ang Evy69kV	8,108	561.6	7,457	561.6
13	LKE Peabdy Wash	865	561.6	936	561.6
14	PJM TVA	36,716	561.6		
15	Shelby Logistics-FS	866	561.6		
16	LKE Pavilion-FS	385	561.6		
17	KMPA Paducha Load	139	561.6		
18	LKE DNR-BROWN	4,909	561.6		
20	Total	114,207		37,878	
21	**Generation Studies**				
22	Feasibility Study (GS)				
23	G'ville to Wickliffe	246	561.7		
24	Harrdsbrg-Westcliff	461	561.7	1,429	561.7
25	Zion-GRS 69kV	362	561.7		
26	Facilities Study (GS)				
27	Grahamville 161kV	11,949	561.7		
28	Kenton-Wed 138 kV	15,102	561.7		
29	SpncrRd Frmer138 kV	5,269	561.7		
30	KYSte Hospital69kV	9,457	561.7		

31	Brown BESS 345kV	6,618	561.7		
32	System Impact Study (GS)				
33	Spncr Rd to Frmers	631	561.7		
34	KY Ste Hospital 69kV	7,678	561.7		
35	Kenton-Wedonia	61	561.7	1,079	561.7
36	Brown BESS345kV	708	561.7		
37	Grahamville161kV	2,145	561.7		
38	Earl to Madison 69kV	500	561.7		
39	DorchBlack 69kV	5,822	561.7		
39	Total	67,009		2,508	
40	Grand Total	181,216		40,386	

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During Quarter/Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	[(a)](#) ARO Generation Coal Combustion Residuals	213,243,012	9,844,488	407	18,277,783	204,809,717
2	ASC 715 - Pension and Postretirement	96,091,380	17,421,274	926/107	33,230	113,479,424
3	Plant Outage Normalization	28,421,347		510-514/553/554	5,129,794	23,291,553
4	Pension Gain/Loss Amortization - 15 Year	39,897,098	(4,612,117)			35,284,981
5	ASC 740 - Income Taxes	31,717,961	3,233,819	410/411/282/283	924,046	34,027,734
6	Forward Starting Swaps Losses	23,921,283		427	2,397,988	21,523,295
7	Asset Retirement Obligation	19,777,658	4,386,804	230	183,243	23,981,219
8	Summer Storm 2018	2,555,708		593	479,195	2,076,513
9	Municipal Formula Rate True-Up	749,332	1,220,731	447	1,160,048	810,015
10	Rate Case Expenses	211,486	104,382	928	211,486	104,382
11	AMI Capital - KY Electric	705,909	95,360			801,269
12	Off-Systems Sales Tracker	625,000	350,000	440-445	666,000	309,000
13	AMI O&M - KY Electric	6,994,981	6,704,536			13,699,517
14	Utility Settlement	7,500,000	1,126,220			8,626,220
15	2023 Wind Storm	11,016,643				11,016,643
16	Environmental Cost Recovery	992,000	476,000	440-445	1,468,000	
17	Generation Capital		34,817			34,817
18	May 2024 Storms		4,998,332			4,998,332
19	September 2024 Storms		10,608,235			10,608,235
20	KY Fuel Adjustment Clause	201,000	13,948,000	440-445	14,149,000	
44	TOTAL	484,621,798	69,940,881		45,079,813	509,482,866

Page 232

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

The information below includes the rate order or document number, if applicable and the period of amortization for each regulatory asset listed on page 232.

ARO Generation Coal Combustion Residuals
Order/docket number :
KPSC 2020-00349
VSCC PUR 2019-00060
Amortization Period: Amortization period for closed plants is from July 2016 through June 2026 and amortization period for open plants is from July 2016 extending through June 2041.

ASC 715 - Pension and Postretirement
Order/docket number :
KPSC 2020-00349
FERC AI07-1-000
VSCC PUR 2019-00060
Amortization Period : Ongoing

Plant Outage Normalization
Order/docket number :
KPSC 2020-00349
Amortization Period : July 2021 to June 2029

Pension Gain/Loss Amortization - 15 Year
Order/docket number:
KPSC 2020-00349
Amortization Period : Ongoing

ASC 740 - Income Taxes
Order/docket number :
KPSC 2020-00349
VSCC PUR 2019-00060
Amortization Period : Ongoing

Forward Starting Swaps Losses
Order/docket number :
KPSC 2020-00349
VSCC PUR 2019-00060
Amortization Period : September 2015 to October 2045

Asset Retirement Obligation
Order/docket number :
KPSC 2020-00349
FERC ER08-1588-000
VSCC PUR 2019-00060
Amortization Period : Ongoing
Summer Storm 2018
Order/docket number :
KPSC 2020-00349
Amortization Period : May 2019 to April 2029

Municipal Formula Rate True-Up
Order/docket number:
FERC ER-13-2428
Amortization Period : Ongoing

Rate Case Expenses
Order/docket number :
KPSC 2020-00349
Amortization Period : July 2021 through June 2024

AMI Capital- KY Electric
Order/docket number
KPSC 2020-00349

Off-System Sales Tracker
Order/docket number :
KPSC 2020-00349
807 KAR 5:056
Amortization Period : Ongoing

AMI O&M - KY Electric
Order/docket number
KPSC 2020-00349

Utility Settlement
Order/docket number:
KPSC 2021-00462

2023 Wind Storm
Order/docket number:
KPSC 2023-00093

Environmental Cost Recovery

Order/docket number:
KRS 278.183
Amortization Period : Ongoing

Generation Capital
Order/docket number:
KPSC 2022-00402

May 2024 Storms
Order/docket number:
KPSC 2024-00181

September 2024 Storms
Order/docket number:
KPSC 2024-00329
KY Fuel Adjustment Clause
Order/docket number:
807 KAR 5:056
Amortization Period : Ongoing

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Miscellaneous Deferred Debits	13,802	24,110	142, 128	26,587	11,325
2	Finance Expense		348,762	181, 428, 923	286,502	62,260
3	Key Man Life Insurance	28,123,804	1,182,215			29,306,019
4	Unamortized Debt Expense	1,409,920	292,331	930.2	289,109	1,413,142
5	Advanced Contract Payments		15,098,833	107	1,344,709	13,754,124
6	Pole Attachment Application	198,361	4,168,737	142, 174	4,367,098	0
7	Cane Run 7 LTPC Asset	16,773,287	10,057,640	107, 108, 553	22,220,150	4,610,777
8	Brown 6 and 7 LTSA Asset	1,817,030	607,252			2,424,282
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	48,336,204				51,581,929

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Interest Rate Swaps	7,113,022	6,754,332
3	Other Post Retirement & Employment Benefits	10,627,003	10,406,231
4	Regulatory Tax Adjustments	153,077,156	146,971,361
5	Coal Combustion Residual ARO	6,169,572	5,359,749
6	Excess Deferred Taxes	9,028,616	8,675,829
7	Workers' Compensation	663,425	604,934
8	Environmental Cost Recovery		1,483,777
9	Vacation Pay	1,119,972	1,227,591
10	R&D Costs - Section 174	2,690,028	
11	Leases	5,158,232	6,158,100
12	Air Permit Fees	729,018	895,940
13	State Tax Credit Carryforward	3,927,198	3,507,452
14	Asset Retirement Obligation	10,217,371	10,719,709
15	Valuation Allowances	(2,310,750)	(1,848,600)
16	Demand Side Management	354,041	2,500,988
17	Fuel Adjustment Clause KY		1,263,967
7	Other	1,443,086	3,321,481
8	TOTAL Electric (Enter Total of lines 2 thru 7)	210,006,990	208,002,841
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other Deductions	323,403	323,411
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	[(a)]210,330,393	[(b)]208,326,252

Notes

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Balance at Beginning of Year	$	221,787,021
Less Debits to:		
Account 410.1		13,855,354
Account 410.2		4
Other Balance Sheet Accounts		6,773,133
Plus Credits to:		
Account 411.1		9,171,759
Account 411.2		104
Balance at End of Year	$	210,330,393

(b) Concept: AccumulatedDeferredIncomeTaxes

Balance at Beginning of Year	$	210,330,393
Less Debits to:		
Account 410.1		5,097,194
Account 410.2		1
Other Balance Sheet Accounts		8,699,721
Plus Credits to:		
Account 411.1		11,792,766
Account 411.2		9
Balance at End of Year	$	208,326,252

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	Common Stock, Without Par Value	80,000,000			37,817,878	308,139,978				
6	Total	80,000,000			37,817,878	308,139,978				
7	Preferred Stock (Account 204)									
8	Perferred Stock, Without Par Value	5,300,000								
9	Preference Stock, Without Par Value	2,000,000								
14	Total	7,300,000								

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-03-18	Year/Period of Report End of: 2024/ Q4

Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
c. Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
d. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	1,000,358,083
15.1	Capital Contributions	126,000,000
15.2	Return of Capital to Parent	(103,000,000)
16	Ending Balance Amount	1,023,358,083
17	**Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	1,023,358,083

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Expenses on Common Stock	321,289
22	TOTAL	321,289

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a)principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	[a] Pollution Control Bonds:												
3	Carroll County 2002 Series A, due 02/01/2032, Variable	221	20,930,000		120,138			05/23/2002	02/01/2032	05/23/2002	02/01/2032	20,930,000	770,399
4	Carroll County 2002 Series B, due 02/01/2032, Variable	221	2,400,000		83,078			05/23/2002	02/01/2032	05/23/2002	02/01/2032	2,400,000	88,607
5	Mercer County 2002 Series A, due 02/01/2032, Variable	221	7,400,000		92,678			05/23/2002	02/01/2032	05/23/2002	02/01/2032	7,400,000	273,206
6	Muhlenberg County 2002 Series A, due 02/01/2032, Variable	221	2,400,000		93,078			05/23/2002	02/01/2032	05/23/2002	02/01/2032	2,400,000	88,037
7	Carroll County 2004 Series A, due 10/01/2034, 1.750%	221	50,000,000		1,795,795			10/20/2004	10/01/2034	10/20/2004	10/01/2034	50,000,000	875,000
8	Carroll County 2006 Series B, due 10/01/2034, 2.125%	221	54,000,000		2,013,646			02/23/2007	10/01/2034	02/23/2007	10/01/2034	54,000,000	1,147,500
9	Carroll County 2008 Series A, due 02/01/2032, 2.000%	221	77,947,405		1,569,861			10/17/2008	02/01/2032	10/17/2008	02/01/2032	77,947,405	1,558,948
10	Carroll County 2016 Series A, due 09/01/2042, 1.550%	221	96,000,000		1,446,180			08/25/2016	09/01/2042	08/25/2016	09/01/2042	96,000,000	1,488,000
11	Carroll County 2018 Series A, due 02/01/2026, 3.375%	221	17,875,000		580,514			09/05/2018	02/01/2026	09/05/2018	02/01/2026	17,875,000	603,281
12	Trimble County 2023 Series A, due 06/01/2054, 4.700%	221	60,000,000		711,006			12/06/2023	06/01/2054	12/06/2023	06/01/2054	60,000,000	2,820,000
13	[b] First Mortgage Bonds:												
14	2010 due 11/01/2040, 5.125%	221	750,000,000		7,480,434		8,137,500	11/16/2010	11/01/2040	11/16/2010	11/01/2040	750,000,000	38,437,500
15	2013 due 11/15/2043, 4.650%	221	250,000,000		2,773,770		1,800,000	11/14/2013	11/15/2043	11/14/2013	11/15/2043	250,000,000	10,187,368
16	2015 due 10/01/2025, 3.300%	221	250,000,000		2,014,576		107,500	09/28/2015	10/01/2025	09/28/2015	10/01/2025	250,000,000	9,659,230
17	2015 due 10/01/2045, 4.375%	221	550,000,000		5,907,847	(5,535,000)	207,500	09/28/2015	10/01/2045	09/28/2015	10/01/2045	550,000,000	25,051,258

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
18	2020 due 06/01/2050, 3.300%	221	500,000,000		5,482,003		2,455,000	06/03/2020	06/01/2050	06/03/2020	06/01/2050	500,000,000	16,500,000
19	2023 due 04/15/2033, 5.450%	221	400,000,000		3,528,990		912,000	03/20/2023	04/15/2033	03/20/2023	04/15/2033	400,000,000	21,800,000
20	Subtotal		3,088,952,405		35,693,594	(5,535,000)	13,619,500					3,088,952,405	131,348,334
21	Reacquired Bonds (Account 222)												
22													
23													
24													
25	Subtotal												
26	Advances from Associated Companies (Account 223)												
27													
28													
29													
30	Subtotal												
31	Other Long Term Debt (Account 224)												
32	Mid-Term Debt:												
33		224											
33	Subtotal												
33	TOTAL		3,088,952,405									3,088,952,405	[(c)] 131,348,334

Page 256-257

FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription

Pollution control series bonds are obligations of KU, issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates KU to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds.

(b) Concept: ClassAndSeriesOfObligationCouponRateDescription

Proceeds from KU's First Mortgage Bonds issued in 2010 were used to repay the loans from a PPL subsidiary and for general corporate purposes. Proceeds from KU's First Mortgage Bond issued in 2013 were used for capital expenditures and general corporate purposes. Proceeds from KU's First Mortgage Bonds issued in 2015 were used to pay maturing debt, pay down short-term debt, and general corporate purposes. The First Mortgage Bonds were issued at a discount. Proceeds from KU's First Mortgage Bonds issued in 2020 were used to repay the maturing 2010 First Mortgage Bonds. The First Mortgage Bonds were issued at a discount. Proceeds from KU's First Mortgage Bonds issued in 2023 were used to repay short-term debt and for other general corporate purposes. The First Mortgage Bonds were issued at a discount.

As of December 31, 2024, all the Company's long-term debt is collateralized by a first mortgage lien on substantially all the assets of the Company in Kentucky.

(c) Concept: InterestExpenseOnLongTermDebtIssued

The amount reported of $131,348,334 represents the balance in Account 427. The difference between the reported amount and the sum of Account 427 and 430 is due to the $2,019,701 in Account 430, which is related to Kentucky Utilities' allocation of interest related to intercompany debt with an affiliate.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	355,591,111
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	15,661,919
6	Over/Under Collections - VA Fuel Clause	917,000
7	Environmental Cost Recovery	6,939,000
8	Demand Side Management	8,605,000
9	Fuel Adjustment Clause KY	5,267,000
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal Income Taxes: Utility Operating Income	87,597,714
11	Amortization of Regulatory Asset/Liability Associated with Net Forward Starting Swaps	960,356
12	Amortization of Storm Regulatory Assets	479,197
13	Capitalized Interest	30,048,002
14	Coal Combustion Residual ARO	8,460,061
15	Contingent Liabilities	669,028
16	Customer Advances for Construction	18,664,968
17	Investment Tax Credit	262,886
18	Non-Deductible Expenses	2,275,051
19	Plant Outage Normalization	5,129,794
20	R & D Costs - Section 174	8,897,404
21	Other	4,040,330
14	Income Recorded on Books Not Included in Return	
15	Investment Tax Credit	1,944,696
16	Muni True-Up Regulatory Asset	60,683
17	AFUDC Flow Through	6,985,145
18	AFUDC Debt	4,014,390
19	Deductions on Return Not Charged Against Book Income	
20	Federal Income Taxes: Other Income and Deductions	1,008,280

Line No.	Particulars (Details) (a)	Amount (b)
21	Provision for Deferred Income Taxes	13,144,225
22	May 2024 Storms	4,998,332
23	September 2024 Storms	10,608,236
24	AMI Regulatory Assets and Liabilities	1,391,741
25	Cost of Removal	31,933,122
26	Life Insurance	1,182,215
27	Pensions	6,475,314
28	Post Employment Benefits	514,378
29	Post Retirement Benefits	370,479
30	Tax Over Book Depreciation, Net and Repairs	50,883,023
31	Other	2,196,307
27	Federal Tax Net Income	422,755,255
28	Show Computation of Tax:	
29	Federal Tax Net Income	422,755,255
30	21% Rounded	88,778,604
31	Less: Tax Credits and Adjustments to Prior Years' Taxes to Accrual	2,189,170
32	Total	86,589,434
	Page 261	

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	[a] Income	Income Tax	Federal	2024	3,272,112	0	86,546,915	85,219,617		4,599,410		87,597,714			(1,050,799)
2					0	0				0					
3	**Subtotal Federal Tax**				3,272,112	0	86,546,915	85,219,617		4,599,410		87,597,714			(1,050,799)
4	Income	Income Tax	Kentucky	2024	144,035	0	17,453,327	16,549,983		1,047,379		17,706,029			(252,702)
5	Public Service Commission	Other License And Fees Tax	Kentucky	2024	0	1,250,497	2,620,428	2,739,863		0	1,369,932	2,620,428			
6	**Subtotal State Tax**				144,035	1,250,497	20,073,755	19,289,846		1,047,379	1,369,932	20,326,457			(252,702)
7	Kentucky and Virginia	Property Tax	Kentucky and Virginia	2024	27,005,843	0	48,151,427	45,627,661		29,529,609		46,059,635			2,091,792
8	**Subtotal Property Tax**				27,005,843	0	48,151,427	45,627,661		29,529,609		46,059,635			2,091,792
9	Federal and Kentucky Unemployment Insurance	Unemployment Tax	Federal and Kentucky	2024	19,109	0	64,386	61,782		21,713		101,143			(36,757)
10	**Subtotal Unemployment Tax**				19,109	0	64,386	61,782		21,713		101,143			(36,757)
11	Kentucky Use Tax	Sales And Use Tax	Kentucky	2024	548,105	0	7,195,649	7,048,747		695,007		42,844			7,152,805
12	Virginia Use Tax	Sales And Use Tax	Virginia	2024	16,284	0	326,225	306,369		36,140					326,225
13	**Subtotal Sales And Use Tax**				564,389	0	7,521,874	7,355,116		731,147		42,844			7,479,030

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
14	Miscellaneous	Miscellaneous Other Tax	Federal and Kentucky	2024	0	0				0		76,694			(76,694)
15	**Subtotal Miscellaneous Other Tax**				0	0				0		76,694			(76,694)
16	FICA	Payroll Tax	Federal	2024	704,787	0	7,370,273	7,406,233		668,827		9,504,140			(2,133,867)
17	**Subtotal Payroll Tax**				704,787	0	7,370,273	7,406,233		668,827		9,504,140			(2,133,867)
18	**Subtotal Other Taxes And Fees**				0	0				0					
40	TOTAL				31,710,275	1,250,497	169,728,630	164,960,255		36,598,085	1,369,932	163,708,627			6,020,003

Page 262-263

Page 262-263

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfTaxesAccruedPrepaidAndCharged

Segregation of Other	Other (I)	Page 117 Other Inc & Deductions 408.2 - 409.2	Other Accounts
Income	$ (1,050,799)	$ (1,008,280)	$ (42,519)
FICA	(2,133,867)	—	(2,133,867)
Total Federal Tax	(3,184,666)	(1,008,280)	(2,176,386)
Income	(252,702)	(252,702)	—
Public Service Commission	—	—	—
Total State Tax	(252,702)	(252,702)	—
Kentucky and Virginia	2,091,792	396	2,091,396
Total Property Tax	2,091,792	396	2,091,396
Federal and Kentucky Unemployment Insurance	(36,757)	—	(36,757)
Total Unemployment Tax	(36,757)	—	(36,757)
Kentucky Use Tax	7,152,805	—	7,152,805
Virginia Use Tax	326,225	—	326,225
Total Sales and Use Tax	7,479,030	—	7,479,030
Miscellaneous	(76,694)	—	(76,694)
Total Miscellaneous Tax	(76,694)	—	(76,694)
TOTAL	$ 6,020,003	$ (1,260,586)	$ 7,280,589

Reconciliation to Page: 114, Line No.: 14, Column: c

Other:		
Electric Total	$ 163,708,627	
Less Federal Income	(87,597,714)	
Less State Income	(17,706,029)	Form 1 114 -14
Total	$ 58,404,884	$ 58,404,884

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%									
4	7%									
5	10%									
6	15%	76,812,015			420	1,627,919		75,184,096		63 years
7	Various	6,229,585	411.4	262,886	420	316,776		6,175,695		25 and 63 years
8	TOTAL Electric (Enter Total of lines 2 thru 7)	83,041,600		262,886		1,944,695		81,359,791		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL	83,041,600		262,886		1,944,695		81,359,791		

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Deferred Compensation	399			35	434
2	Uncertain Tax Position - Federal	645,314			42,519	687,833
3	Long Term Retainage	26,128	232	26,128	606,849	606,849
4	Uncertain Tax Position - Interest	62,388			53,560	115,948
47	TOTAL	734,229		26,128	702,963	1,411,064

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)										
18	Classification of TOTAL										
19	Federal Income Tax										
20	State Income Tax										
21	Local Income Tax										

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	[(a)]996,194,931	128,645,602	139,153,912			182/190/254/283	5,680,944	182/190/254/283	21,590,649	[(b)]1,001,596,326
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	996,194,931	128,645,602	139,153,912				5,680,944		21,590,649	1,001,596,326
6	Other	(1,061,890)	416,959	16,839							(661,770)
9	TOTAL Account 282 (Total of Lines 5 thru 8)	995,133,041	129,062,561	139,170,751				5,680,944		21,590,649	1,000,934,556
10	Classification of TOTAL										
11	Federal Income Tax	819,629,889	103,266,784	116,208,525				4,824,831		19,510,063	821,373,380
12	State Income Tax	175,502,952	25,795,777	22,962,226				856,113		2,080,586	179,560,976
13	Local Income Tax										

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2023, is $5,282,844 and the Coal Combustion Residual ARO balance is $3,558,737.

The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2023, is ($378,014,790). Please see Footnote 6, Income and Other Taxes, within the Notes to Financial Statements for additional detail.

The Lease right-of-use assets balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2023, is $5,153,226.

(b) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2024, is $4,736,393 and the Coal Combustion Residual ARO balance is $2,742,236.

The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2024, is ($359,407,397). Please see Footnote 6, Income and Other Taxes, within the Notes to Financial Statements for additional detail.

The Lease right-of-use assets balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2024, is $6,144,036.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Interest Rate Swaps	5,968,361	25,179	623,477							5,370,063
4	Regulatory Tax Adjustments	7,913,631					182	516,024	182	1,092,312	8,489,919
5	Coal Combustion Residual ARO	53,204,132	263,258	2,367,366							51,100,024
6	Excess Deferred Taxes	598,513									598,513
7	Pension - Regulatory Asset	27,143,300	3,798,284	1,248,209							29,693,375
8	Asset Retirement Obligation	4,934,527	1,092,926	44,137							5,983,316
9	Fuel Adjustment Clause KY	50,150	764,008	814,158							
10	Rate Case Expenses	52,766	15,059	41,781							26,044
11	Pensions	10,147,256	2,931,791	3,866,275							9,212,772
12	Other	3,114,170	2,608,736	1,459,433			282	247,214	282	51,915	4,068,174
13	Loss on Reacquired Debt	1,727,222	6,323	156,571							1,576,974
14	Plant Outage Normalization Regulatory Asset	7,091,127	53,863	1,333,746							5,811,244
15	Casualty Loss - Storm Damages	3,386,304	4,062,739	288,460							7,160,583
16	Utility Settlement Regulatory Asset	1,871,250	292,817	11,825							2,152,242
9	TOTAL Electric (Total of lines 3 thru 8)	127,202,709	15,914,983	12,255,438				763,238		1,144,227	131,243,243
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)
18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	127,202,709	15,914,983	12,255,438				763,238		1,144,227	131,243,243
20	Classification of TOTAL										
21	Federal Income Tax	101,560,378	12,955,619	9,966,778				425,124		937,838	105,061,933
22	State Income Tax	25,642,331	2,959,364	2,288,660				338,114		206,389	26,181,310
23	Local Income Tax										

NOTES

Page 276-277

Page 276-277

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	[(a)] ASC 740- Income Taxes	554,896,276	410/411/190/282	23,067,098	87,395	531,916,573
2	ASC 715 - Pension and Postretirement	37,206,778	926 / 107	492,496	690,646	37,404,928
3	Forward Starting Swaps Gains	28,509,104	427	1,437,632		27,071,472
4	Environmental Cost Recovery		440-445	2,709,000	8,656,000	5,947,000
5	DSM Cost Recovery	1,419,000	440-445	798,000	9,403,000	10,024,000
6	AMI Legacy Meters	308,869			1,346,845	1,655,714
7	VA Fuel Component	41,000	440-445	437,000	1,354,000	958,000
8	AMI O&M - KY Electric	2,626,203			4,458,684	7,084,887
9	KY Fuel Adjustment Clause		440-445	6,305,000	11,371,000	5,066,000
10	Off-Systems Sales Tracker		440-445	443,000	443,000	
11	Municipal Formula Rate True-Up		440-445	142,984	142,984	
41	TOTAL	625,007,230		35,832,210	37,953,554	627,128,574

Page 278

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The information below includes the rate order or document number, if applicable and the period of amortization for each regulatory liability listed on page 278.

ASC 740 - Income Taxes
Order/docket number:
KPSC 2020-00349
VSCC PUR 2019-00060
Amortization Period : Ongoing

ASC 715 - Pension and Postretirement
Order/docket number:
KPSC 2020-00349
FERC AI07-1-000
VSCC PUR 2019-00060
Amortization Period : Ongoing

Forward Starting Swap Gains
Order/docket number:
KPSC 2020-00349
VSCC PUR 2019-00060
Amortization Period : September 2015 to October 2045

Environmental Cost Recovery
Order/docket number:
KRS 278.183
Amortization Period : Ongoing

DSM Cost Recovery
Order/docket number:
KRS 278.285
Amortization Period : Ongoing

AMI Legacy Meters
Order/docket number:
KPSC 2020-00349

VA Fuel Component
Order/docket number:
Title 56 of the Code of Virginia Chapter 10, Section 56-249.6
Amortization Period : Ongoing

AMI O&M - KY Electric
Order/docket number:
KPSC 2020-00349

KY Fuel Adjustment Clause
Order/docket number:
807 KAR 5:056
Amortization Period : Ongoing

Off-System Sales Tracker
Order/docket number:
KPSC 2020-00349
807 KAR 5:056
Amortization Period : Ongoing

Municipal Formula Rate True-Up
Order/docket number:
FERC ER-13-2428
Amortization Period : Ongoing

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

Electric Operating Revenues

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	749,372,939	708,998,367	6,258,346	5,858,490	473,342	469,424
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	505,153,361	485,294,778	4,153,959	3,922,244	87,625	87,147
5	Large (or Ind.) (See Instr. 4)	444,434,092	449,564,007	6,196,783	6,084,477	1,688	1,710
6	(444) Public Street and Highway Lighting	7,101,636	7,623,733	19,347	20,565	1,530	1,513
7	(445) Other Sales to Public Authorities	158,805,637	152,540,698	1,594,400	1,533,434	9,909	9,818
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	[(a)]1,864,867,665	1,804,021,583	18,222,835	17,419,210	574,094	569,612
11	(447) Sales for Resale	51,676,625	40,108,363	1,312,423	936,584	16	16
12	TOTAL Sales of Electricity	1,916,544,290	1,844,129,946	19,535,258	18,355,794	574,110	569,628
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	1,916,544,290	1,844,129,946	19,535,258	18,355,794	574,110	569,628
15	Other Operating Revenues						
16	(450) Forfeited Discounts	3,894,151	3,639,956				
17	(451) Miscellaneous Service Revenues	1,512,985	2,444,360				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	10,498,469	5,063,216				

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[b]1,261,277	[d]1,167,437				
22	(456.1) Revenues from Transmission of Electricity of Others	[c]36,559,293	[e]30,492,757				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
25.1	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	53,726,175	42,807,726				
27	TOTAL Electric Operating Revenues	1,970,270,465	1,886,937,672				

Line12, column (b) includes $ [f](17,830,916.00) of unbilled revenues.
Line12, column (d) includes [g]35,930 MWH relating to unbilled revenues

Page 300-301

Page 300-301

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: SalesToUltimateConsumers

Lighting Service, Restricted Lighting Service, Lighting Energy Service & Traffic Energy Services provided to customers are unmetered sales. These customers are charged according to the tariff rates through rate schedules LS, RLS, LE & TE and are included in each customer class, with a majority of the unmetered sales recorded in FERC 444, Public Street and Highway Lighting .

(b) Concept: OtherElectricRevenue

East Kentucky Power Cooperative	$	377,283
Renewable Energy Credit		290,302
Other items less than $250,000 each		593,692
Total for Other Electric Revenues (456)	$	1,261,277

(c) Concept: RevenuesFromTransmissionOfElectricityOfOthers

East Kentucky Power Cooperative	$	16,857,651
Kentucky Municipal Energy Agency		6,779,719
Owensboro Municipal Utilities		3,586,445
Kentucky Municipal Power Agency		3,719,048
Tennessee Valley Authority		2,036,553
Midcontinent Independent System Operator		1,023,901
Louisville Gas and Electric Company		594,900
City of Bardstown		912,910
City of Nicholasville		892,981
Other items less than $250,000 each		155,185
Total for Revenues from Transmission of Electricity of Others (456.1)	$	36,559,293

(d) Concept: OtherElectricRevenue

East Kentucky Power Cooperative	$	374,882
Other items less than $250,000 each		792,555
Total for Other Electric Revenues (456)	$	1,167,437

(e) Concept: RevenuesFromTransmissionOfElectricityOfOthers

East Kentucky Power Cooperative	$	13,871,231
Kentucky Municipal Energy Agency		5,993,028
Owensboro Municipal Utilities		3,042,608
Kentucky Municipal Power Agency		2,852,486
Tennessee Valley Authority		1,628,406
Midcontinent Independent System Operator		1,030,488
Louisville Gas and Electric Company		337,442
City of Bardstown		803,303
City of Nicholasville		772,016
Other items less than $250,000 each		161,749
Total for Revenues from Transmission of Electricity of Others (456.1)	$	30,492,757

(f) Concept: RevenueFromSalesOfElectricityUnbilled

The net unbilled revenue represents the following:

Base Revenue	$	4,122,000
Fuel Adjustment Clause		(5,267,000)
Demand Side Management		(8,605,000)
Environmental Cost Recovery		(6,939,000)
Off-System Sales Tracker		(316,000)
Levelized Fuel Factor		(917,000)
Solar Capacity Charge		91,084
Net Unbilled	$	(17,830,916)

(g) Concept: MegawattHoursOfElectricitySoldUnbilled

Unbilled revenues and MWH represent the net change in unbilled revenues and MWH from the previous period, therefore the change could be positive or negative.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Page 302

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Service - KY (440)	5,903,831	[b]703,851,005	449,574	13,132	0.1192
2	Residential Time-of-Day E - KY (440)	1,748	[c]189,732	107	16,336	0.1085
3	Residential Time-of-Day D - KY (440)	12	[d]2,371	1	12,000	0.1976
4	General Service - KY (440)	1,409	[e]213,214	943	1,494	0.1513
5	Lighting Service - KY (440)	17,830	[f]5,087,318	38,376	465	0.2853
6	Restricted Lighting Service - KY (440)	1,678	[g]330,618	2,163	776	0.1970
7	Residential Service - VA (440)	319,712	45,215,477	22,575	14,162	0.1414
8	General Service - VA (440)	81	12,465	146	555	0.1539
9	Private Outdoor Lighing - VA (440)	2,277	849,068	4,659	489	0.3729
10	Street Lighting Service - VA (440)	123	29,262	5	24,600	0.2379
11	Duplicate Customers (440)			(45,207)		
12	[a]Reclassifications and Adjustments (440)	24	6,264			0.2610
41	TOTAL Billed Residential Sales	6,248,725	755,786,794	473,342	13,201	0.1210
42	TOTAL Unbilled Rev. (See Instr. 6)	9,621	(6,413,855)			(0.6667)
43	TOTAL	6,258,346	749,372,939	473,342	13,222	0.1197

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfNumberAndTitleOfRateSchedule
Includes current and prior period reclassifications between FERC accounts and net billing adjustments. Negative amounts are due to adjustments or the net presentation of unbilled volumes.
(b) Concept: ResidentialSalesBilled
Includes Fuel Adjustment Clause of ($161,334)
(c) Concept: ResidentialSalesBilled
Includes Fuel Adjustment Clause of ($103)
(d) Concept: ResidentialSalesBilled
Includes Fuel Adjustment Clause of ($2)
(e) Concept: ResidentialSalesBilled
Includes Fuel Adjustment Clause of ($200)
(f) Concept: ResidentialSalesBilled
Includes Fuel Adjustment Clause of ($1,371)
(g) Concept: ResidentialSalesBilled
Includes Fuel Adjustment Clause of ($66)

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Service - KY (442)	576	[b]67,581	191	3,016	0.1173
2	General Service - KY (442)	1,555,577	[c]243,616,624	76,850	20,242	0.1566
3	All Electric School - KY (442)	12,416	[d]1,434,459	69	179,942	0.1155
4	Power Service - KY (442)	1,243,435	[e]142,509,547	3,250	382,595	0.1146
5	Time of Day Secondary Svc - KY (442)	791,824	[f]66,488,866	366	2,163,454	0.0840
6	Time of Day Primary Service - KY (442)	271,907	[g]21,728,764	47	5,785,255	0.0799
7	Retail Transmission Service - KY (442)	56,715	[h]3,092,084	2	28,357,500	0.0545
8	Lighting Service - KY (442)	39,502	[i]9,692,399	18,714	2,111	0.2454
9	Restricted Lighting Service - KY (442)	6,530	[j]1,457,463	2,344	2,786	0.2232
10	Lighting Energy Service - KY (442)	949	[k]72,065	53	17,906	0.0759
11	Elec Vehicle Charging Svc - KY (442)	60	[l]11,968	11	5,455	0.1995
12	Outdoor Sports Lighting Svc - KY (442)	77	[m]14,279	1	77,000	0.1854
13	General Time of Day Service - KY (442)	727	[n]94,056	24	30,292	0.1294
14	Residential Service - VA (442)	2,099	283,937	176	11,926	0.1353
15	General Service - VA (442)	60,445	8,749,953	3,488	17,329	0.1448
16	Power Service - VA (442)	66,507	7,346,925	127	523,677	0.1105
17	Time of Day Secondary Svc - VA (442)	17,946	1,845,226	7	2,563,714	0.1028
18	Time of Day Primary Service - VA (442)	12,438	1,707,936	6	2,073,000	0.1373
19	Private Outdoor Lighing - VA (442)	1,038	338,218	878	1,182	0.3258
20	Street Lighting Service - VA (442)	8	1,890	1	8,000	0.2363
21	Duplicate Customers (442)			(18,980)		
22	[a]Reclassifications and Adjustments (442)	592	79,708			0.1346
41	TOTAL Billed Small or Commercial	4,141,368	510,633,948	87,625	47,262	0.1233
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	12,591	(5,480,587)			(0.4353)
43	TOTAL Small or Commercial	4,153,959	505,153,361	87,625	47,406	0.1216

Page 304

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfNumberAndTitleOfRateSchedule

Includes current and prior period reclassifications between FERC accounts and net billing adjustments. Negative amounts are due to adjustments or the net presentation of unbilled volumes

(b) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Includes Fuel Adjustment Clause of $80

(c) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Includes Fuel Adjustment Clause of ($155,420)

(d) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Includes Fuel Adjustment Clause of $1,225

(e) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Includes Fuel Adjustment Clause of ($144,603)

(f) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Includes Fuel Adjustment Clause of ($102,388)

(g) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Includes fuel adjustment clause of $9,544

(h) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Includes fuel adjustment clause of ($146,285)

(i) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Includes fuel adjustment clause of ($1,990)

(j) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Includes fuel adjustment clause of ($113)

(k) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Includes Fuel Adjustment Clause of $105

(l) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Includes Fuel Adjustment Clause of $(238)

(m) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Includes Fuel Adjustment Clause of $7

(n) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Includes Fuel Adjustment Clause of ($1,527)

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	General Service - KY (442)	60,284	[b]8,146,677	738	81,686	0.1351
2	Power Service - KY (442)	130,323	[c]17,372,200	357	365,050	0.1333
3	Time of Day Secondary Svc - KY (442)	788,932	[d]69,325,193	258	3,057,876	0.0879
4	Time of Day Primary Service - KY (442)	3,095,610	[e]223,671,804	163	18,991,472	0.0723
5	Retail Transmission Service - KY (442)	1,505,210	[f]98,069,188	18	83,622,778	0.0652
6	Fluctuating Load Servcie - KY (442)	532,440	[g]22,210,498	1	532,440,000	0.0417
7	Lighting Service - KY (442)	1,788	[h]371,398	654	2,734	0.2077
8	Restricted Lighting Service - KY (442)	608	[i]99,586	111	5,477	0.1638
9	Special Contract - KY (442)		219,934	1		
10	General Service - VA (442)	1,362	179,926	36	37,833	0.1321
11	Power Service - VA (442)	10,828	1,730,120	10	1,082,800	0.1598
12	Time of Day Secondary Svc - VA (442)	1,350	170,104	1	1,350,000	0.1260
13	Time of Day Primary Service - VA (442)	53,678	6,089,401	7	7,668,286	0.1134
14	Retail Transmission Service - VA (442)	4,578	891,367	2	2,289,000	0.1947
15	Private Outdoor Lighing - VA (442)	20	6,694	34	588	0.3347
16	Duplicate Customers (442)			(703)		
17	[a]Reclassifications and Adjustments (442)	2	4,914			2.4570
41	TOTAL Billed Large (or Ind.) Sales	6,187,013	448,559,004	1,688	3,665,292	0.0725
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	9,770	(4,124,912)			(0.4222)
43	TOTAL Large (or Ind.)	6,196,783	444,434,092	1,688	3,671,080	0.0717

Page 304

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfNumberAndTitleOfRateSchedule

Includes current and prior period reclassifications between FERC accounts and net billing adjustments. Negative amounts are due to adjustments or the net presentation of unbilled volumes.

(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled

Includes Fuel Adjustment Clause of ($7,520)

(c) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled

Includes Fuel Adjustment Clause of $1,625

(d) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled

Includes Fuel Adjustment Clause of ($8,414)

(e) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled

Includes Fuel Adjustment Clause of $225,053

(f) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled

Includes Fuel Adjustment Clause of $1,343,849

(g) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled

Includes fuel adjustment clause of $991,739

(h) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled

Includes fuel adjustment clause of ($142)

(i) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled

Includes fuel adjustment clause of ($21)

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	General Service - KY (444)		[b]635	782		
2	Lighting Service - KY (444)	15,870	[c]6,307,801	993	15,982	0.3975
3	Restricted Lighting Service - KY (444)	2,217	[d]640,559	113	19,619	0.2889
4	Lighting Energy Service - KY (444)	214	[e]16,171	20	10,700	0.0756
5	Traffic Energy Service - KY (444)	990	[f]115,264	602	1,645	0.1164
6	Private Outdoor Lighing - VA (444)	49	16,867	14	3,500	0.3442
7	Street Lighting Service - VA (444)	606	172,191	29	20,897	0.2841
8	Duplicate Customers (444)			(1,023)		
9	[a]Reclassifications and Adjustments (444)	(437)	(49,852)			0.1141
41	TOTAL Billed Public Street and Highway Lighting	19,509	7,219,636	1,530	12,751	0.3701
42	TOTAL Unbilled Rev. (See Instr. 6)	(162)	(118,000)			0.7284
43	TOTAL	19,347	7,101,636	1,530	12,645	0.3671

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfNumberAndTitleOfRateSchedule

Includes current and prior period reclassifications between FERC accounts and net billing adjustments. Negative amounts are due to adjustments or the net presentation of unbilled volumes.

(b) Concept: PublicStreetAndHighwayLightingBilled

Includes fuel adjustment clause of $0

(c) Concept: PublicStreetAndHighwayLightingBilled

Includes fuel adjustment clause of $2,884

(d) Concept: PublicStreetAndHighwayLightingBilled

Includes fuel adjustment clause of $1,701

(e) Concept: PublicStreetAndHighwayLightingBilled

Includes fuel adjustment clause of ($15)

(f) Concept: PublicStreetAndHighwayLightingBilled

Includes fuel adjustment clause of $169

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Service - KY (445)	4,874	[b]650,645	691	7,054	0.1335
2	Volunteer Fire Department - KY (445)	1,131	[c]130,990	66	17,136	0.1158
3	General Service - KY (445)	135,914	[d]21,022,499	5,753	23,625	0.1547
4	All Electric School - KY (445)	108,078	[e]12,276,255	332	325,536	0.1136
5	Power Service - KY (445)	285,740	[f]34,644,074	683	418,360	0.1212
6	Time of Day Secondary Svc - KY (445)	257,844	[g]23,965,443	165	1,562,691	0.0929
7	Time of Day Primary Service - KY (445)	650,334	[h]48,567,335	47	13,836,894	0.0747
8	Retail Transmission Service - KY (445)	49,833	[i]3,110,082	1	49,833,000	0.0624
9	Lighting Service - KY (445)	20,214	[j]6,231,442	3,373	5,993	0.3083
10	Restricted Lighting Service - KY (445)	2,944	[k]975,450	390	7,549	0.3313
11	Lighting Energy - KY (445)	3,764	[l]285,697	92	40,913	0.0759
12	Traffic Energy Service - KY (445)	1,052	[m]130,793	536	1,963	0.1243
13	Outdoor Sports Lighting Svc - KY (445)	309	[n]100,728	5	61,800	0.3260
14	Residential Service - VA (445)	663	96,970	63	10,524	0.1463
15	General Service - VA (445)	13,407	1,915,907	690	19,430	0.1429
16	Power Service - VA (445)	14,617	1,732,886	37	395,054	0.1186
17	Time of Day Secondary Svc - VA (445)	2,495	269,320	2	1,247,500	0.1079
18	Time of Day Primary Service - VA (445)	15,136	1,333,260	2	7,568,000	0.0881
19	Private Outdoor Lighing - VA (445)	669	216,936	295	2,268	0.3243
20	Street Lighting Service - VA (445)	752	210,976	45	16,711	0.2806
21	School Service - VA (445)	20,048	2,574,873	128	156,625	0.1284
22	Water Pumping Service - VA (445)	651	55,179	15	43,400	0.0848
23	Duplicate Customers (445)			(3,502)		
24	[a]Reclassifications and Adjustments (445)	(180)	1,459			(0.0081)
41	TOTAL Billed Other Sales to Public Authorities	1,590,289	160,499,199	9,909	160,489	0.1009
42	TOTAL Unbilled Rev. (See Instr. 6)	4,111	(1,693,562)			(0.4120)
43	TOTAL	1,594,400	158,805,637	9,909	160,904	0.0996

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfNumberAndTitleOfRateSchedule
Includes current and prior period reclassifications between FERC accounts and net billing adjustments. Negative amounts are due to adjustments or the net presentation of unbilled volumes.
(b) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of ($965)
(c) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of $60
(d) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of $3,513
(e) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of $3,638
(f) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of ($16,271)
(g) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of $528
(h) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of $46,696
(i) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of $7,438
(j) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of $671
(k) Concept: OtherSalesToPublicAuthoritiesBilled
Includes Fuel Adjustment Clause of ($402)
(l) Concept: OtherSalesToPublicAuthoritiesBilled
Includes Fuel Adjustment Clause of $122
(m) Concept: OtherSalesToPublicAuthoritiesBilled
Includes Fuel Adjustment Clause of $194
(n) Concept: OtherSalesToPublicAuthoritiesBilled
Includes Fuel Adjustment Clause of ($8)

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	18,186,904	1,882,698,581	574,094	31,679	0.1035
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	35,931	(17,830,916)			(0.4963)
43	TOTAL - All Accounts	18,222,835	1,864,867,665	574,094	31,742	0.1023

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

   SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

   LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

   OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

   AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	City of Bardstown	RQ	[(af)] 185	29	29	30	183,375	6,058,274	1,000,550	[(bq)] 4,919,335	11,978,159
2	City of Nicholasville	RQ	[(ag)] 157	29	29	29	170,205	5,910,066	919,071	[(br)] 4,421,139	11,250,276
3	Altop Energy Trading LLC	[(c)] OS	[(ah)] (3)				18		734		734
4	Associated Electric Cooperative Inc.	[(d)] OS	[(ai)] (3)				1,063		41,542		41,542
5	Big Rivers Electric Corp.	[(e)] OS	[(aj)] (17)							[(bs)] 88	88
6	Constellation Generation Company, LLC	[(f)] OS	[(ak)] (3)				473		28,957		28,957
7	Dominion Energy South Carolina, Inc.	[(g)] OS	[(al)] (3)				85		3,769		3,769

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW) Average Monthly NCP Demand (e)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
8	Duke Energy Carolinas, LLC	[(h)] OS	[(am)] (3)				586		27,148		27,148
9	Duke Energy Florida, LLC	[(i)] OS	[(an)] (3)				155		8,307		8,307
10	Dynasty Power, Inc.	[(j)] OS	[(ao)] (3)				34		1,477		1,477
11	East Kentucky Power Cooperative	[(k)] OS	[(ap)] (SA 4)				18		543	[(bt)] 162,870	163,413
12	ETC Endure Energy, LLC	[(l)] OS	[(aq)] (3)				2		71		71
13	Hoosier Energy Rural Electric Coop	[(m)] OS	[(ar)] (17)							[(bu)] 962	962
14	[(a)] Indiana Municipal Power Agency	[(n)] OS	[(as)] (CB SA4)				838		27,807		27,807
15	Indiana Municipal Power Agency	[(o)] OS	[(at)] (SA 3)				239		7,375		7,375
16	Kentucky Municipal Energy Agency	[(p)] OS	[(au)] (CB 23)				88		3,078		3,078
17	Kentucky Municipal Energy Agency	[(q)] OS	[(av)] (SA 23)				3,690		114,747	[(bv)] 516,174	630,921
18	Kentucky Municipal Power Agency	[(r)] OS	[(aw)] (SA13) (17)				903		31,753	[(bw)] 282,407	314,160
19	[(b)] Louisville Gas and Electric Company	SF	[(ax)] (RS 508)				821,872		19,296,212		19,296,212
20	Louisville Gas and Electric Company	[(s)] OS	[(ay)] (17)							[(bx)] 5,818	5,818
21	Macquarie Energy, LLC	[(t)] OS	[(az)] (3)				11,844		738,735		738,735
22	Midcontinent Independent System Operat.	[(u)] OS	[(ba)] (3)				34,988		2,277,058		2,277,058
23	North Carolina Electric Membership Corporation	[(v)] OS	[(bb)] (3)				1,851		76,245		76,245
24	Owensboro Municipal Utilities	[(w)] OS	[(bc)] (CB 15)				470		31,943		31,943
25	Owensboro Municipal Utilities	[(x)] OS	[(bd)] (SA 15)				1,290		40,547	[(by)] 299,060	339,607
26	PJM Settlement, Inc.	[(y)] OS	[(be)] (3)				51,392		2,844,909		2,844,909
27	Rainbow Energy Marketing Corporation	[(z)] OS	[(bf)] (3)				15,693		871,284		871,284
28	Southern Company Services, Inc.	[(aa)] OS	[(bg)] (3)				1,452		63,863		63,863
29	Tennessee Valley Authority	[(ab)] OS	[(bh)] (3)				5,830		313,904		313,904
30	Tennessee Valley Authority	[(ac)] OS	[(bi)] (SA 11)				21		652	[(bz)] 19,584	20,236
31	The Energy Authority	[(ad)] OS	[(bj)] (3)				3,331		145,961		145,961
32	The Energy Authority	[(ae)] OS	[(bk)] (10)				590		22,376		22,376
33	City of Bardstown	AD	185					[(bm)] 130,383	[(bo)] (61,745)		68,638
34	City of Nicholasville	AD	157					[(bn)] 128,752	[(bp)] (61,148)		67,604
35	Appalachian Power Company	RQ	[(bl)] 408				27		2,411	[(ca)] 1,577	3,988
15	Subtotal - RQ						353,607	11,968,340	1,922,032	9,342,051	23,232,423
16	Subtotal-Non-RQ						958,816	259,135	26,898,104	1,286,963	28,444,202

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW) Average Monthly NCP Demand (e)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
17	Total						1,312,423	12,227,475	28,820,136	10,629,014	51,676,625
Page 310-311											

Page 310-311

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale

Indiana Municipal Power Agency has a 12.88% ownership interest in LG&E's and KU's Trimble County Generating Unit No. 2.

(b) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale

KU and LG&E are owned by LKE.

(c) Concept: StatisticalClassificationCode

Market Based Sales

(d) Concept: StatisticalClassificationCode

Market Based Sales

(e) Concept: StatisticalClassificationCode

Schedule 2 Reactive Supply and Voltage Control

(f) Concept: StatisticalClassificationCode

Market Based Sales

(g) Concept: StatisticalClassificationCode

Market Based Sales

(h) Concept: StatisticalClassificationCode

Market Based Sales

(i) Concept: StatisticalClassificationCode

Market Based Sales

(j) Concept: StatisticalClassificationCode

Market Based Sales

(k) Concept: StatisticalClassificationCode

Schedule 4 Energy Imbalance Service
Schedule 2 Reactive Supply and Voltage Control
Schedule 12 Distribution of Penalty Revenues.

(l) Concept: StatisticalClassificationCode

Market Based Sales

(m) Concept: StatisticalClassificationCode

Schedule 2 Reactive Supply and Voltage Control
Schedule 12 Distribution of Penalty Revenues

(n) Concept: StatisticalClassificationCode

Cost Based Sales

(o) Concept: StatisticalClassificationCode

Schedule 9 Generator Imbalance

(p) Concept: StatisticalClassificationCode

Cost Based Sales

(q) Concept: StatisticalClassificationCode

Schedule 4 Energy Imbalance Service
Schedule 2 Reactive Supply and Voltage Control
Schedule 3 Regulation and Frequency Response Service
Schedule 5 Operating Reserve-Spinning Reserve Service
Schedule 6 Operating Reserve-Supp. Reserve Service
Schedule 12 Distribution of Penalty Revenues

(r) Concept: StatisticalClassificationCode

Schedule 4 Energy Imbalance Service
Schedule 2 Reactive Supply and Voltage Control
Schedule 3 Regulation and Frequency Response Service
Schedule 5 Operating Reserve-Spinning Reserve Service
Schedule 6 Operating Reserve-Supp. Reserve Service
Schedule 12 Distribution of Penalty Revenues

(s) Concept: StatisticalClassificationCode
Schedule 2 Reactive Supply and Voltage Control
(t) Concept: StatisticalClassificationCode
Market Based Sales
(u) Concept: StatisticalClassificationCode
Market Based Sales
(v) Concept: StatisticalClassificationCode
Market Based Sales
(w) Concept: StatisticalClassificationCode
Cost Based Sales
(x) Concept: StatisticalClassificationCode
Schedule 4 Energy Imbalance Service Schedule 2 Reactive Supply and Voltage Control Schedule 3 Regulation and Frequency Response Service Schedule 5 Operating Reserve-Spinning Reserve Service Schedule 6 Operating Reserve-Supp. Reserve Service Schedule 12 Distribution of Penalty Revenues
(y) Concept: StatisticalClassificationCode
Market Based Sales
(z) Concept: StatisticalClassificationCode
Market Based Sales
(aa) Concept: StatisticalClassificationCode
Market Based Sales
(ab) Concept: StatisticalClassificationCode
Market Based Sales
(ac) Concept: StatisticalClassificationCode
Schedule 4 Energy Imbalance Service Schedule 2 Reactive Supply and Voltage Control Schedule 12 Distribution of Penalty Revenues
(ad) Concept: StatisticalClassificationCode
Market Based Sales
(ae) Concept: StatisticalClassificationCode
Cost Based Sales
(af) Concept: RateScheduleTariffNumber
Rate Schedule FERC No. 185.
(ag) Concept: RateScheduleTariffNumber
Rate Schedule FERC No. 157.
(ah) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(ai) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(aj) Concept: RateScheduleTariffNumber
(17) LG&E and KU Joint ProForma Open Access Transmission Tariff Attachment F ProForma NITSA
(ak) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(al) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(am) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(an) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(ao) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(ap) Concept: RateScheduleTariffNumber
(SA 4) LG&E and KU Joint ProForma Open Access Transmission Tariff - Attachment F NITSA FERC No. 4

(aq) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(ar) Concept: RateScheduleTariffNumber
(17) LG&E and KU Joint ProForma Open Access Transmission Tariff - Attachment F ProForma NITSA
(as) Concept: RateScheduleTariffNumber
(CB SA4) LG&E and KU CBR Tariff Service Agreement No. 4
(at) Concept: RateScheduleTariffNumber
(SA 3) LG&E and KU Joint Pro Forma Open Access Transmission Tariff Attachment A Long-Term Firm PTP Transmission Service Agreement FERC No. 3
(au) Concept: RateScheduleTariffNumber
(10) LG&E and KU CBR Tariff ProForma Service Agreement
(av) Concept: RateScheduleTariffNumber
(SA 23) LG&E and KU Joint ProForma Open Access Transmission Tariff - Attachment F NITSA FERC No. 23
(aw) Concept: RateScheduleTariffNumber
(17) Effective 9/6/2023 executed ProForma Attachment F NITSA.
(ax) Concept: RateScheduleTariffNumber
(RS 508) Effective June 4, 2018 LG&E and KU Joint Rate Schedule No. 508 Amended and Restated Power Supply System Agreement.
(ay) Concept: RateScheduleTariffNumber
(17) LG&E and KU Joint ProForma Open Access Transmission Tariff Attachment F ProForma NITSA
(az) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(ba) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(bb) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(bc) Concept: RateScheduleTariffNumber
(10) LG&E and KU CBR Tariff ProForma Service Agreement
(bd) Concept: RateScheduleTariffNumber
(SA 15) LG&E and KU Joint ProForma Open Access Transmission Tariff - Attachment F NITSA FERC No. 15
(be) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(bf) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(bg) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(bh) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(bi) Concept: RateScheduleTariffNumber
(SA 11) LG&E and KU Joint ProForma Open Access Transmission Tariff - Attachment F NITSA FERC No. 11
(bj) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(bk) Concept: RateScheduleTariffNumber
(10) LG&E and KU CBR Tariff ProForma Service Agreement
(bl) Concept: RateScheduleTariffNumber
Appalachian Power Company Rate Schedule FERC No. 408. KU d/b/a Old Dominion Power is making wholesale Borderline Service sales to Appalachian Power Company for purposes of accommodating Appalachian Power Company retail sales to the High Knob residential customers at rates consistent with ODP's Virginia Commission approved retail tariff as may be amended from time to time (consistent with precedent for such borderline agreements as provided for under the rules and order of the Commission).
(bm) Concept: DemandChargesRevenueSalesForResale
2023 correction made in 2024
(bn) Concept: DemandChargesRevenueSalesForResale
2023 correction made in 2024
(bo) Concept: EnergyChargesRevenueSalesForResale
2023 correction made in 2024
(bp) Concept: EnergyChargesRevenueSalesForResale

2023 correction made in 2024
(bq) Concept: OtherChargesRevenueSalesForResale
Amounts include RQ's related to $181,444 for direct assignment charge and $4,737,891 for wholesale municipal fuel adjustment clause.
(br) Concept: OtherChargesRevenueSalesForResale
Amounts include RQ's related to $8,880 for direct assignment charge and $4,412,259 for wholesale municipal fuel adjustment clause.
(bs) Concept: OtherChargesRevenueSalesForResale
Transmission revenues-Schedule 2, $89; Transmission revenue credits-Schedule 12, $.1
(bt) Concept: OtherChargesRevenueSalesForResale
Transmission revenues-Schedule 2, $164,432; Transmission revenue credits-Schedule 12, $1,562
(bu) Concept: OtherChargesRevenueSalesForResale
Transmission revenues-Schedule 2, $970; Transmission revenue credits-Schedule 12, $8.
(bv) Concept: OtherChargesRevenueSalesForResale
Transmission revenues-Schedule 2, $65,723; Schedule 3, $109,914; Schedule 5, $170,367; Schedule 6, $170,367; Transmission revenue credits-Schedule 12, $197
(bw) Concept: OtherChargesRevenueSalesForResale
Transmission revenues-Schedule 2, $36,663; Schedule 3, $59,975; Schedule 5, $92,961; Schedule 6, $92,961; Transmission revenue credits-Schedule 12, $153
(bx) Concept: OtherChargesRevenueSalesForResale
Schedule 2 transmission revenues
(by) Concept: OtherChargesRevenueSalesForResale
Transmission revenues-Schedule 2, $38,161; Schedule 3, $63,678; Schedule 5, $98,701; Schedule 6, $98,701; Transmission revenue credits-Schedule 12, $181
(bz) Concept: OtherChargesRevenueSalesForResale
Transmission revenues-Schedule 2, $19,973; Transmission revenue credits-Schedule 12, $389
(ca) Concept: OtherChargesRevenueSalesForResale
Amounts include RQ's related to $660 for direct assignment charge and $917 for wholesale municipal fuel adjustment clause.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	4,358,803	4,768,245
5	(501) Fuel	356,822,559	332,148,174
6	(502) Steam Expenses	9,841,936	16,092,812
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	7,359,160	6,924,268
10	(506) Miscellaneous Steam Power Expenses	28,653,030	26,854,256
11	(507) Rents		
12	(509) Allowances	1,385	1,249
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	407,036,873	386,789,004
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	11,447,688	10,921,485
16	(511) Maintenance of Structures	8,360,704	8,350,590
17	(512) Maintenance of Boiler Plant	37,269,054	36,311,118
18	(513) Maintenance of Electric Plant	10,248,103	8,510,690
19	(514) Maintenance of Miscellaneous Steam Plant	3,178,740	2,308,534
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	70,504,289	66,402,417
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	477,541,162	453,191,421
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	108,338	74,062
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	108,338	74,062
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	15,346	7,265
54	(542) Maintenance of Structures	313,971	245,069
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant	305,587	229,744
57	(545) Maintenance of Miscellaneous Hydraulic Plant	13,611	23,879
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	648,515	505,957
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	756,853	580,019
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	657,801	691,804
63	(547) Fuel	123,739,527	118,869,871
64	(548) Generation Expenses	823,764	730,079
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	6,075,827	5,580,452
66	(550) Rents	8,231	8,672
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	131,305,150	125,880,878
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,314,253	932,628

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
70	(552) Maintenance of Structures	1,174,396	1,036,522
71	(553) Maintenance of Generating and Electric Plant	8,530,666	5,902,353
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	3,118,367	2,725,572
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	14,137,682	10,597,075
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	145,442,832	136,477,953
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	52,777,410	53,019,918
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	2,251,996	2,468,669
78	(557) Other Expenses	221,423	(131,503)
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	55,250,829	55,357,084
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	678,991,676	645,606,477
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,021,635	2,122,289
85	(561.1) Load Dispatch-Reliability	354,143	314,415
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,678,483	2,696,513
87	(561.3) Load Dispatch-Transmission Service and Scheduling	681,844	636,370
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	732,897	597,138
90	(561.6) Transmission Service Studies	76,329	549
91	(561.7) Generation Interconnection Studies	64,501	(2,563)
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,129,922	1,314,611
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	907,859	1,027,544
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	3,454,180	4,026,347
97	(566) Miscellaneous Transmission Expenses	34,132,810	36,293,875
98	(567) Rents	273,865	352,039
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	46,508,468	49,379,127
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		618
104	(569.2) Maintenance of Computer Software	1,623,587	1,552,735
105	(569.3) Maintenance of Communication Equipment		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,053,646	2,039,300
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	8,778,987	7,508,692
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	252,370	190,482
111	TOTAL Maintenance (Total of Lines 101 thru 110)	11,708,590	11,291,827
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	58,217,058	60,670,954
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	2,960	2,178
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	2,960	2,178
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software	35,982	25,812
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	35,982	25,812
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	38,942	27,990
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,328,967	2,589,104
135	(581) Load Dispatching		
136	(582) Station Expenses	1,195,998	1,443,097
137	(583) Overhead Line Expenses	6,548,942	7,439,247
138	(584) Underground Line Expenses	1,970,527	1,808,499
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	9,725,923	10,763,937
141	(587) Customer Installations Expenses	670	198

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
142	(588) Miscellaneous Expenses	8,791,504	8,126,019
143	(589) Rents		
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	30,562,531	32,170,101
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	21,059	19,040
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	523,937	875,849
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	22,247,777	25,070,725
150	(594) Maintenance of Underground Lines	332,645	360,353
151	(595) Maintenance of Line Transformers	39,490	72,856
152	(596) Maintenance of Street Lighting and Signal Systems		
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant	799,720	892,503
155	TOTAL Maintenance (Total of Lines 146 thru 154)	23,964,628	27,291,326
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	54,527,159	59,461,427
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	4,239,028	4,115,259
160	(902) Meter Reading Expenses	5,573,230	7,938,703
161	(903) Customer Records and Collection Expenses	19,061,158	19,669,571
162	(904) Uncollectible Accounts	3,594,541	2,541,887
163	(905) Miscellaneous Customer Accounts Expenses	4,379	130
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	32,472,336	34,265,550
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	317,771	418,147
168	(908) Customer Assistance Expenses	7,933,088	7,654,542
169	(909) Informational and Instructional Expenses	886,121	1,048,460
170	(910) Miscellaneous Customer Service and Informational Expenses	1,657,861	1,557,046
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	10,794,841	10,678,195
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	690,207	(1,327,477)
176	(913) Advertising Expenses	81,463	85,801
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	771,670	(1,241,676)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	28,380,458	31,133,454
182	(921) Office Supplies and Expenses	6,866,874	7,116,984
183	(Less) (922) Administrative Expenses Transferred-Credit	4,103,134	4,488,895
184	(923) Outside Services Employed	20,275,887	25,132,103
185	(924) Property Insurance	10,751,389	10,441,134
186	(925) Injuries and Damages	4,660,113	5,721,482
187	(926) Employee Pensions and Benefits	16,509,032	19,306,640
188	(927) Franchise Requirements	5,310	5,400
189	(928) Regulatory Commission Expenses	1,169,377	1,356,388
190	(929) (Less) Duplicate Charges-Cr.	5,310	5,400
191	(930.1) General Advertising Expenses	1,019,993	1,553,465
192	(930.2) Miscellaneous General Expenses	4,903,244	6,524,845
193	(931) Rents	2,573,203	3,054,446
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	93,006,436	106,852,046
195	Maintenance		
196	(935) Maintenance of General Plant	2,051,670	2,068,875
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	95,058,106	108,920,921
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	930,871,788	918,389,838
	Page 320-323		

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

   SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

   LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

   EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

   OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

   AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES: MegaWatt Hours Received (i)	POWER EXCHANGES: MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER: Demand Charges ($) (k)	COST/SETTLEMENT OF POWER: Energy Charges ($) (l)	COST/SETTLEMENT OF POWER: Other Charges ($) (m)	COST/SETTLEMENT OF POWER: Total (k+l+m) of Settlement ($) (n)
1	Associated Electric Cooperative, Inc.	[g] OS	[bc] (5)				44					532		532
2	Autozone, Inc	[h] OS	[bd] (12)				31					823		823
3	Carlisle Armory	[i] OS	[be] (12)				35					940		940
4	Core Controls	[j] OS	[bf] (12)				31					876		876
5	Carroll Co Bd of ED	[k] OS	[bg] (12)				16					418		418

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
6	Centre College	[l] OS	[bh] (12)				3					148		148
7	Department of Military Affairs	[m] OS	[bi] (12)				188					4,870		4,870
8	Douglas Langley	[n] OS	[bj] (12)				25					652		652
9	Dominion Energy South Carolina, Inc	[o] OS	[bk] (8)				26					357		357
10	Duke Energy Carolinas, LLC	[p] OS	[bl] (8)				3,353					42,496		42,496
11	Duke Energy Florida, LLC	[q] OS	[bm] (8)				13,043					157,954		157,954
12	East Kentucky Power Cooperative, Inc.	[r] OS	[bn] (11)				1,803					63,507		63,507
13	East Kentucky Power Cooperative, Inc.	[s] OS	[bo] (SA4)				73					2,468		2,468
14	Farmers Feed Mill	[t] OS	[bp] (12)				223					5,800		5,800
15	Fayette County Public Schools	[u] OS	[bq] (12)				35					908		908
16	Heath Elementary School	[v] OS	[br] (12)				63					1,886		1,886
17	[a] Indiana Municipal Power Agency	[w] OS	[bs] (SA3)				2,277					69,241		69,241
18	Kentucky Municipal Energy Agency	[x] OS	[bt] (SA23)				1,005					26,710		26,710
19	Kentucky Municipal Power Agency	[y] OS	[bu] (17)				1,473					43,444		43,444
20	J R Hoe and Son	[z] OS	[bv] (12)				1					37		37
21	Kentucky National Guard	[aa] OS	[bw] (12)				80					2,069		2,069
22	Link-Belt Cranes LP, LLLP	[ab] OS	[bx] (12)				4					110		110
23	Lyon Co Bd of ED	[ac] OS	[by] (12)				133					3,405		3,405
24	[b] Louisville Gas and Electric Company	[ad] SF	[bz] (RS 508)				1,124,088					30,395,534		30,395,534
25	North Carolina Electric Membership Corporation	[ae] OS	[ca] (9)				101					1,409		1,409
26	[c] Ohio Valley Electric Corporation - Demand	[af] OS	[cb] (6)								11,549,206			11,549,206
27	Ohio Valley Electric Corporation - Demand	[ag] AD	[cc] (6)										[cy] 93,086	93,086

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
28	[d] Ohio Valley Electric Corporation - Energy	[ah] OS	[cd] (6)				247,493					9,236,449		9,236,449
29	Ohio Valley Electric Corporation - Energy	[ai] AD	[ce] (6)										[gz] 128,725	128,725
30	Owensboro Municipal Utilities	[aj] OS	[cf] (SA15)				1,075					30,598		30,598
31	PJM Settlement, Inc.	[ak] OS	[cg] (16)				4,962					52,115		52,115
32	Southern Company Services, Inc.	[al] OS	[ch] (13)				1,464					20,410		20,410
33	Rockcastle Co High School	[am] OS	[ci] (12)				3					70		70
34	Russ County Library	[an] OS	[cj] (12)				22					583		583
35	Shelbyville Armory	[ao] OS	[ck] (12)				52					1,356		1,356
36	Swope Motors, Inc	[ap] OS	[cl] (12)				21					551		551
37	Swope Nissan, LLC	[aq] OS	[cm] (12)				65					1,656		1,656
38	Tiffany and Company	[ar] OS	[cn] (12)				80					2,067		2,067
39	Trinity Industrial Corp	[as] OS	[co] (12)				65					1,734		1,734
40	Tampa Electric Company	[at] OS	[cp] (8)				293					4,371		4,371
41	Tennessee Valley Authority	[au] OS	[cq] (RS28)				14,473					182,549		182,549
42	Tennessee Valley Authority	[av] OS	[cr] (4)				129					15,718		15,718
43	Tennessee Valley Authority	[aw] OS	[cs] (SA11)				106					2,977		2,977
44	The Energy Authority	[ax] OS	[ct] (14)				279					3,343		3,343
45	Waityn 4JC Mobilization	[ay] OS	[cu] (12)				8					208		208
46	[e] Simpsonville Solar	[az] OS	[cv] (12)									8,037		8,037
47	[f] Business Solar	[ba] OS	[cw] (12)									6,179		6,179
48	Net Metering Service - 2	[bb] OS	[cx] (12)				8,762					608,828		608,828
49	Inadvertent								403,834					
15	TOTAL						1,427,506		403,834		11,549,206	41,006,393	221,811	52,777,410

Page 326-327

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Indiana Municipal Power Agency has a 12.88% ownership interest in LG&E's Trimble County Generating Unit No. 1. They additionally have a 12.88% ownership interest in LG&E's and KU's Trimble County Generating Unit No. 2.

(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

KU and LG&E are owned by LKE.

(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Intercompany Power Agreement dated September 10, 2010. The Company owns 2.5% of the common stock of OVEC. Purchase of available energy and available power pursuant to Article 4 of the Amended and Restated Intercompany Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.

(d) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Intercompany Power Agreement dated September 10, 2010. The Company owns 2.5% of the common stock of OVEC. Purchase of available energy and available power pursuant to Article 4 of the Amended and Restated Intercompany Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.

(e) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Company Community Solar Share Program located in Simpsonville, Kentucky.

(f) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Makers Mark

(g) Concept: StatisticalClassificationCode

Market Based Purchases

(h) Concept: StatisticalClassificationCode

Small Capacity Cogeneration and Small Power Production Qualifying Facility

(i) Concept: StatisticalClassificationCode

Small Capacity Cogeneration and Small Power Production Qualifying Facility

(j) Concept: StatisticalClassificationCode

Large Capacity Cogeneration and Large Power Production Qualifying Facility

(k) Concept: StatisticalClassificationCode

Small Capacity Cogeneration and Small Power Production Qualifying Facility

(l) Concept: StatisticalClassificationCode

Small Capacity Cogeneration and Small Power Production Qualifying Facility

(m) Concept: StatisticalClassificationCode

Large Capacity Cogeneration and Large Power Production Qualifying Facility

(n) Concept: StatisticalClassificationCode

Small Capacity Cogeneration and Small Power Production Qualifying Facility

(o) Concept: StatisticalClassificationCode

Market Based Purchases

(p) Concept: StatisticalClassificationCode

Market Based Purchases

(q) Concept: StatisticalClassificationCode

Market Based Purchases

(r) Concept: StatisticalClassificationCode

Market Based Purchases

(s) Concept: StatisticalClassificationCode

Imbalance

(t) Concept: StatisticalClassificationCode

Small Capacity Cogeneration and Small Power Production Qualifying Facility

(u) Concept: StatisticalClassificationCode

Small Capacity Cogeneration and Small Power Production Qualifying Facility

(v) Concept: StatisticalClassificationCode

Large Capacity Cogeneration and Large Power Production Qualifying Facility
(w) Concept: StatisticalClassificationCode
Imbalance
(x) Concept: StatisticalClassificationCode
Imbalance
(y) Concept: StatisticalClassificationCode
Imbalance
(z) Concept: StatisticalClassificationCode
Small Capacity Cogeneration and Small Power Production Qualifying Facility
(aa) Concept: StatisticalClassificationCode
Large Capacity Cogeneration and Large Power Production Qualifying Facility
(ab) Concept: StatisticalClassificationCode
Small Capacity Cogeneration and Small Power Production Qualifying Facility
(ac) Concept: StatisticalClassificationCode
Small Capacity Cogeneration and Small Power Production Qualifying Facility
(ad) Concept: StatisticalClassificationCode
LG&E and KU PSSA - Amended in 2018
(ae) Concept: StatisticalClassificationCode
Market Based Purchases
(af) Concept: StatisticalClassificationCode
Available Energy and Available Power
(ag) Concept: StatisticalClassificationCode
Available Energy and Available Power
(ah) Concept: StatisticalClassificationCode
Available Energy and Available Power
(ai) Concept: StatisticalClassificationCode
Available Energy and Available Power
(aj) Concept: StatisticalClassificationCode
Imbalance
(ak) Concept: StatisticalClassificationCode
Market Based Purchases
(al) Concept: StatisticalClassificationCode
Market Based Purchases
(am) Concept: StatisticalClassificationCode
Small Capacity Cogeneration and Small Power Production Qualifying Facility
(an) Concept: StatisticalClassificationCode
Small Capacity Cogeneration and Small Power Production Qualifying Facility
(ao) Concept: StatisticalClassificationCode
Small Capacity Cogeneration and Small Power Production Qualifying Facility
(ap) Concept: StatisticalClassificationCode
Large Capacity Cogeneration and Large Power Production Qualifying Facility
(aq) Concept: StatisticalClassificationCode
Large Capacity Cogeneration and Large Power Production Qualifying Facility
(ar) Concept: StatisticalClassificationCode
Large Capacity Cogeneration and Large Power Production Qualifying Facility
(as) Concept: StatisticalClassificationCode
Small Capacity Cogeneration and Small Power Production Qualifying Facility
(at) Concept: StatisticalClassificationCode
Market Purchase
(au) Concept: StatisticalClassificationCode
Market Purchase
(av) Concept: StatisticalClassificationCode

Emergency Power Purchases
(aw) Concept: StatisticalClassificationCode
Imbalance
(ax) Concept: StatisticalClassificationCode
Market Based Purchases
(ay) Concept: StatisticalClassificationCode
Small Capacity Cogeneration and Small Power Production Qualifying Facility
(az) Concept: StatisticalClassificationCode
Large Capacity Cogeneration and Large Power Production Qualifying Facility
(ba) Concept: StatisticalClassificationCode
Large Capacity Cogeneration and Large Power Production Qualifying Facility
(bb) Concept: StatisticalClassificationCode
Residential Customers
(bc) Concept: RateScheduleTariffNumber
WSPP Agreement Effective 8/1/1996
(bd) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(be) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(bf) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(bg) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(bh) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(bi) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(bj) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(bk) Concept: RateScheduleTariffNumber
EEI Master Power Purchase and Sale Agreement dated 12/1/2003
(bl) Concept: RateScheduleTariffNumber
EEI Master Power Purchase and Sale Agreement dated 4/1/2004
(bm) Concept: RateScheduleTariffNumber
EEI Master Power Purchase and Sale Agreement dated 8/15/2023
(bn) Concept: RateScheduleTariffNumber
EEI Master Power Purchase and Sale Agreement dated 9/14/2006
(bo) Concept: RateScheduleTariffNumber
(SA4) LG&E and KU Joint ProForma Open Access Transmission Tariff Schedule 4. NITSA Service Agreement FERC No. 4
(bp) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(bq) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(br) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(bs) Concept: RateScheduleTariffNumber
(SA3) LG&E and KU Joint ProForma Open Access Transmission Tariff Schedule 9. LTF PTP Service Agreement FERC No. 3
(bt) Concept: RateScheduleTariffNumber
(SA23) LG&E and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4. NITSA Service Agreement FERC No. 23
(bu) Concept: RateScheduleTariffNumber
(17) LG&E and KU Joint Pro Forma OATT Schedule 4, effective 9/6/2023 executed ProForma Attachment F NITSA
(bv) Concept: RateScheduleTariffNumber

(12) KPSC Standard Rate Rider
(bw) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(bx) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(by) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(bz) Concept: RateScheduleTariffNumber
(RS 508) Effective June 4, 2018 LG&E and KU Joint Rate Schedule FERC No. 508 Amended and Restated Power Supply System Agreement.
(ca) Concept: RateScheduleTariffNumber
EEI Master Power Purchase and Sale Agreement dated 9/14/2006
(cb) Concept: RateScheduleTariffNumber
(6) Intercompany Power Agreement v 0.0.0 on file with the Commission. Amended and Restated Intercompany Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.
(cc) Concept: RateScheduleTariffNumber
(6) Intercompany Power Agreement v 0.0.0 on file with the Commission. Amended and Restated Intercompany Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.
(cd) Concept: RateScheduleTariffNumber
(6) Intercompany Power Agreement v 0.0.0 on file with the Commission. Amended and Restated Intercompany Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.
(ce) Concept: RateScheduleTariffNumber
(6) Intercompany Power Agreement v 0.0.0 on file with the Commission. Amended and Restated Intercompany Power Agreement among OVEC and Sponsoring Companies dated September 10, 2010.
(cf) Concept: RateScheduleTariffNumber
(SA15) LG&E and KU Joint ProForma Open Access Transmission Tariff Schedule 4. NITSA Service Agreement FERC No. 15
(cg) Concept: RateScheduleTariffNumber
(16) Operating Agreement of PJM Interconnection, LLC Rate Schedule FERC No. 24
(ch) Concept: RateScheduleTariffNumber
EEI Master Power Purchase and Sale Agreement dated 12/7/2007
(ci) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(cj) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(ck) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(cl) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(cm) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(cn) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(co) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(cp) Concept: RateScheduleTariffNumber
EEI Master Power Purchase and Sale Agreement dated 11/4/2024
(cq) Concept: RateScheduleTariffNumber
(RS28) FERC Electric Rate Schedule No. 28 Interchange Agreement effective 7/1/1977-11/6/2024
(cr) Concept: RateScheduleTariffNumber
(4) Contingency Reserve Sharing Agreement dated November 20, 2009.
(cs) Concept: RateScheduleTariffNumber
(SA11) LG&E and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4. NITSA Service Agreement FERC No. 11
(ct) Concept: RateScheduleTariffNumber
WSPP Agreement Effective 8/1/1996
(cu) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(cv) Concept: RateScheduleTariffNumber

(12) KPSC Standard Rate Rider
(cw) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(cx) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(cy) Concept: OtherChargesOfPurchasedPower
December 2023 true-up of accrual estimate for both energy and demand charges made in January 2024.
(cz) Concept: OtherChargesOfPurchasedPower
December 2023 true-up of accrual estimate for both energy and demand charges made in January 2024.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	Midwest ISO	Various	Various	OS	Joint OATT	Various	Various						1,023,901 [(c)]	1,023,901
2	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	FNO	Joint OATT	East Kentucky Power Cooperative	East Kentucky Power Cooperative	401	2,361,456	2,361,456	16,396,103			16,396,103
3	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	NF	Joint OATT	East Kentucky Power Cooperative	East Kentucky Power Cooperative	66	60,943	60,943		457,908		457,908
4	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	SFP	Joint OATT	East Kentucky Power Cooperative	East Kentucky Power Cooperative	28	1,426	1,426		3,639		3,639
5	Kentucky Municipal Power Agency	Midwest ISO	Kentucky Municipal Power Agency	FNO	SA 13	Various	LGEE.KMPA	89	486,038	486,038	3,719,048			3,719,048
6	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	FNO	SA 15	Owensboro Municipal Utilities	Various	97	621,442	621,442	3,577,784			3,577,784
7	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	LFP	SA 15	Owensboro Municipal Utilities	Various		924	924				
8	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	NF	SA 15	Owensboro Municipal Utilities	Various					8,662		8,662
9	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	FNO	Joint OATT	TVA	TVA	46	249,860	249,860	1,932,766			1,932,766
10	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	NF	Joint OATT	TVA	TVA		18,639	18,639		103,787		103,787
11	Big Rivers Electric Corporation	Big Rivers Electric Corporation	Big Rivers Electric Corporation	FNO	Joint OATT	Big Rivers Electric Corporation	Big Rivers Electric Corporation		1,991	1,991	9,394			9,394

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatt Hours Received (i)	TRANSFER OF ENERGY Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
12	Kentucky Municipal Energy Agency	Midwest ISO	Kentucky Municipal Energy Agency	FNO	Joint OATT	Various	LGEE.KYMEA	166	1,015,672	1,015,672	6,778,741			6,778,741
13	Kentucky Municipal Energy Agency	Midwest ISO	Kentucky Municipal Energy Agency	OS	Joint OATT	Various	LGEE.KYMEA						[d]66,533	66,533
14	Kentucky Municipal Energy Agency	Midwest ISO	Kentucky Municipal Energy Agency	NF	Joint OATT	Various	LGEE.KYMEA		104	104		979		979
15	Hoosier Energy	Midwest ISO	Hoosier Energy	FNO	Joint OATT	Midwest ISO	Hoosier Energy	2	19,848	19,848	99,228			99,228
16	[a] KU Transactions	Various	Various	NF	Joint OATT	Various	Various					1,319,067		1,319,067
17	[b] KU Transactions	Various	Various	SFP	Joint OATT	Various	Various				20,744			20,744
18	Appalachian Power Company	Various	Various	FNO	Joint OATT	Various	Various				423			423
19	City of Bardstown	Various	City of Bardstown	FNO	185	Various	City of Bardstown	23			912,910			912,910
20	City of Nicholasville	Various	City of Nicholasville	FNO	157	Various	City of Nicholasville	22			892,981			892,981
35	TOTAL							940	4,838,343	4,838,343	34,340,122	1,894,042	1,090,434	[e]37,324,598

Page 328-330

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority

KU and LG&E are owned by LKE.

(b) Concept: PaymentByCompanyOrPublicAuthority

KU and LG&E are owned by LKE.

(c) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

KU receives ongoing monthly payments from MISO in a Joint Party Settlement Agreement related to uncompensated MISO usage above the 1,000 MW contract right.

(d) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Falmouth fixed charges related to operating expenses and maintenance expenses.

(e) Concept: RevenuesFromTransmissionOfElectricityForOthers

Reconciliation of revenues from transmission of electricity of others to amount reported in electric operating revenues:

Schedule Page: 330.1, Line No.: 35, Column: n	$	37,324,598
Elimination of intracompany transmission revenues		(765,305)
Schedule Page: 300, Line No.: 22, Column: b	$	36,559,293

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
40	TOTAL				
Page 331					

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
   FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	EKPC	LFP					(l)273,321	273,321
2	(a)LG&E	NF	27,320	27,320		249,088	(m)9,062	258,150
3	(b)LG&E	SFP	116	116	667		(n)31	698
4	PJM Interconnect	LFP			2,903,620			2,903,620
5	PJM Interconnect	NF	1,714	1,714		1,564	(o)5,361	6,925
6	PJM Interconnect	OS					(p)63	63
7	Duke Energy Carolinas, LLC	NF				(c)1,935		1,935
8	Municipal Electric Authority of Georgia	NF				(d)331		331
9	South Carolina Public Service Authority	NF				(e)1,960		1,960
10	TVA	NF				(f)6,618		6,618
11	Georgia Transmission Corporation	NF				(g)313		313
12	Dominion Energy South Carolina, Inc	NF				(h)79		79
13	Southern Company Services, Inc	NF				(i)97		97
14	Duke Energy Progress, LLC	NF				(j)32		32
15	Duke Energy Florida, LLC	NF				(k)38		38
	TOTAL		29,150	29,150	2,904,287	262,055	287,838	3,454,180

Page 332

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

KU and LG&E are owned by LKE.

(b) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

KU and LG&E are owned by LKE.

(c) Concept: EnergyChargesTransmissionOfElectricityByOthers

SEEM transmission losses directly related to actual transmission expenses occurred on the SEEM platform

(d) Concept: EnergyChargesTransmissionOfElectricityByOthers

SEEM transmission losses directly related to actual transmission expenses occurred on the SEEM platform

(e) Concept: EnergyChargesTransmissionOfElectricityByOthers

SEEM transmission losses directly related to actual transmission expenses occurred on the SEEM platform

(f) Concept: EnergyChargesTransmissionOfElectricityByOthers

SEEM transmission losses directly related to actual transmission expenses occurred on the SEEM platform

(g) Concept: EnergyChargesTransmissionOfElectricityByOthers

SEEM transmission losses directly related to actual transmission expenses occurred on the SEEM platform

(h) Concept: EnergyChargesTransmissionOfElectricityByOthers

SEEM transmission losses directly related to actual transmission expenses occurred on the SEEM platform

(i) Concept: EnergyChargesTransmissionOfElectricityByOthers

SEEM transmission losses directly related to actual transmission expenses occurred on the SEEM platform

(j) Concept: EnergyChargesTransmissionOfElectricityByOthers

SEEM transmission losses directly related to actual transmission expenses occurred on the SEEM platform

(k) Concept: EnergyChargesTransmissionOfElectricityByOthers

SEEM transmission losses directly related to actual transmission expenses occurred on the SEEM platform

(l) Concept: OtherChargesTransmissionOfElectricityByOthers

Schedule 1 and Schedule 2 charges

(m) Concept: OtherChargesTransmissionOfElectricityByOthers

Schedule 1 and Schedule 2 charges

(n) Concept: OtherChargesTransmissionOfElectricityByOthers

Schedule 1 and Schedule 2 charges.

(o) Concept: OtherChargesTransmissionOfElectricityByOthers

Schedule 1 and Schedule 2 charges.

(p) Concept: OtherChargesTransmissionOfElectricityByOthers

Black Start Service Charges

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	873,625
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	703,419
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	PPL Service Corporation:	
7	Stockholder and Debt Service Expenses	449,894
8	Miscellaneous:	
9	IT Prepaid Subscriptions	760,536
10	Software Subscriptions	254,332
11	Depreciation Reclass	1,025,605
12	Debt Expense for Revolvers	360,293
13	Commitment Fees on Revolvers	407,778
14	LG&E Center Move	64,842
15	Other Miscellaneous Expenses:	
16	6 Items <$5,000 each	
17	Various Vendors	2,920
46	TOTAL	4,903,244

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

1. Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
   Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
   For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			15,793,128		15,793,128
2	Steam Production Plant	230,445,226				230,445,226
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	1,518,176				1,518,176
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	32,650,672				32,650,672
7	Transmission Plant	42,393,405				42,393,405
8	Distribution Plant	47,296,741				47,296,741
9	Regional Transmission and Market Operation					
10	General Plant	14,648,166				14,648,166
11	Common Plant-Electric					
12	TOTAL	368,952,386		15,793,128		[(a)]384,745,514

B. Basis for Amortization Charges

[(b)] See footnote

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production Plant						
13	311 Structures and Improvements						
14	5623 Brown Unit 3 (311)	30,271	100 years	(4)%	3.29%	100-R2.5	8 years
15	5630 Brown Units 1-3 FGD (311)	45,606	100 years	(4)%	4.68%	100-R2.5	8 years
16	312 Boiler Plant Equipment						
17	5623 Brown Unit 3 (312)	504,729	65 years	(4)%	5.39%	65-R1.5	7 years, 11 months
18	5623 Brown Unit 3 Ash Pond (312)	19,802	100 years		4.05%	100-S4	0 years
19	5630 Brown Units 1-3 FGD (312)	336,174	65 years	(4)%	5.08%	65-R1.5	7 years, 11 months
20	314 Turbogenerator Units						
21	5623 Brown Unit 3 (314)	51,310	60 years	(4)%	5.5%	60-R1.5	7 years, 9 months
22	315 Accessory Electric Equipment						
23	5623 Brown Unit 3 (315)	16,347	70 years	(4)%	3.89%	70-R4	7 years, 11 months
24	5630 Brown Units 1-3 FGD (315)	29,236	70 years	(4)%	4.9%	70-R4	8 years
25	316 Miscellaneous Power Plant Equipment						
26	5623 Brown Unit 3 (316)	8,070	70 years	(4)%	3.5%	70-R1.5	7 years, 11 months

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DepreciationAndAmortization

Depreciation rates were updated effective July 1, 2021 based on a depreciation study dated June 30, 2020.

(b) Concept: BasisAmortizationCharges

B: Basis for Amortization Charges

Account	Rate	Plant Balance at 12/31/2024	Amortization	
130200	4%	55,919	2,030	
130300	21%	54,702,969	13,696,130	
130310	10%	14,448,869	1,453,556	
130330	21%	2,755,112	484,873	
130332	21%	679,660	15,244	
130340	21%	608,831	130,047	
130342	21%	222,011	11,248	
			15,793,128	Column (d)

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	FERC - Annual Charge	595,343		595,343		Electric	928	595,343				
2	KPSC Rate Case - 2020-00349 (Amort period: Jul 2021-Jun 2024)		211,486	211,486	211,486	Electric				928	211,486	
3	KPSC Rate Case - Ongoing					Electric			104,382			104,382
4	2024 VA LFF		4,459	4,459		Electric	928	4,459				
5	2024 Rate Case - VSCC Case No. PUR-2024-00052		322,722	322,722		Electric	928	322,722				
6	Other		35,367	35,367		Electric	928	35,367				
46	TOTAL	595,343	574,034	1,169,377	211,486			957,891	104,382		211,486	104,382

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:
   - A. Electric R, D and D Performed Internally:
     1. Generation
        - a. hydroelectric
          - i. Recreation fish and wildlife
          - ii. Other hydroelectric
        - b. Fossil-fuel steam
        - c. Internal combustion or gas turbine
        - d. Nuclear
        - e. Unconventional generation
        - f. Siting and heat rejection
     2. Transmission
        - a. Overhead
        - b. Underground
     3. Distribution
     4. Regional Transmission and Market Operation
     5. Environment (other than equipment)
     6. Other (Classify and include items in excess of $50,000.)
     7. Total Cost Incurred
   - B. Electric, R, D and D Performed Externally:
     1. Research Support to the electrical Research Council or the Electric Power Research Institute
     2. Research Support to Edison Electric Institute
     3. Research Support to Nuclear Power Groups
     4. Research Support to Others (Classify)
     5. Total Cost Incurred
3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	A(1)e: Generation: Unconventional	Wind Turbine	146,600	17,133	107, 930	163,734	
2	A(6): Other	Various R&D Internal Projects and Initiatives	715,347		107, 549, 930	715,347	
3	B(1) EPRI	General		5,200	930	5,200	
4	B(1) EPRI	Generation		619,850	107, 549	619,850	
5	B(1) EPRI	Distribution		107,494	588	107,494	
6	B(1) EPRI	Transmission		74,813	566	74,813	
7	B(4): Research Support to Others	Research related to the integration of intermittent renewables, energy storage, carbon capture, other technologies to improve operations and to reduce emissions or improve environmental sustainability.		305,195	107, 930	305,195	
8	Total		861,947	1,129,685		1,991,633	

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	24,392,710		
4	Transmission	5,561,865		
5	Regional Market			
6	Distribution	10,921,841		
7	Customer Accounts	11,682,445		
8	Customer Service and Informational	1,364,438		
9	Sales	3,291		
10	Administrative and General	22,075,999		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	76,002,589		
12	Maintenance			
13	Production	19,419,610		
14	Transmission	825,805		
15	Regional Market			
16	Distribution	2,854,650		
17	Administrative and General	706,458		
18	TOTAL Maintenance (Total of lines 13 thru 17)	23,806,523		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	43,812,320		
21	Transmission (Enter Total of lines 4 and 14)	6,387,670		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	13,776,491		
24	Customer Accounts (Transcribe from line 7)	11,682,445		
25	Customer Service and Informational (Transcribe from line 8)	1,364,438		
26	Sales (Transcribe from line 9)	3,291		
27	Administrative and General (Enter Total of lines 10 and 17)	22,782,457		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	99,809,112	29,059,598	128,868,710
29	Gas			
30	Operation			
31	Production - Manufactured Gas			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	99,809,112	29,059,598	128,868,710
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	41,248,148	30,661,014	71,909,162
69	Gas Plant			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	41,248,148	30,661,014	71,909,162
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,836,433	1,684,186	4,520,619
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,836,433	1,684,186	4,520,619
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Accounts Receivable	55,492	9,768	65,260
80	Fuel Stock			
81	Deferred Debits	4,667,479	21,734	4,689,213
82	Certain Civic, Political and Related Activities and Other	301,179	84,816	385,995
83	Accounts Receivable (Non-jurisdictional - Trimble County)	2,103,547	607,648	2,711,195
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	7,127,697	723,966	7,851,663
96	TOTAL SALARIES AND WAGES	151,021,390	62,128,764	213,150,154
Page 354-355				

Page 354-355

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	34,847	8,209		9,059
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(188,789)	(1,186,578)	(3,501,425)	(245,174)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	(153,942)	(1,178,369)	(3,501,425)	(236,115)
Page 397					

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	29,150	MWH	201,254	4,838,343	MWH	796,531
2	Reactive Supply and Voltage	29,150	MWH	86,521	4,838,343	MWH	326,012
3	Regulation and Frequency Response				2,124,180	MWH	233,567
4	Energy Imbalance	6,009	MWH	175,438	6,161	MWH	195,617
5	Operating Reserve - Spinning				2,124,180	MWH	362,029
6	Operating Reserve - Supplement				2,124,180	MWH	362,029
7	Other			[a]63			[b]1,023,901
8	Total (Lines 1 thru 7)	[c]64,309		463,276	[d]16,055,387		3,299,686

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedAmount

The amount consists of Black Start services charges from MISO. The other services amounts are not associated with a number of units or a unit of measure.

(b) Concept: AncillaryServicesSoldAmount

The amount consists of MISO Joint Party Settlement Payments. The other services amounts are not associated with a number of units or a unit of measure.

(c) Concept: AncillaryServicesPurchasedNumberOfUnits

The number of units per ancillary service type cover multiple schedules and should not be accumulated in total.

(d) Concept: AncillaryServicesSoldNumberOfUnits

The number of units per ancillary service type cover multiple schedules and should not be accumulated in total.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: Kentucky Utilities Company									
1	January	5,704	17	9	4,474	991	239			
2	February	4,141	19	9	3,207	695	239			
3	March	3,933	19	7	2,985	709	239			
4	Total for Quarter 1				10,666	2,395	717			
5	April	3,557	15	18	2,658	660	239			
6	May	4,146	21	17	3,092	815	239			
7	June	4,556	17	15	3,524	787	245			
8	Total for Quarter 2				9,274	2,262	723			
9	July	4,773	15	17	3,569	959	245			
10	August	4,644	28	17	3,517	882	245			
11	September	4,261	5	17	3,156	860	245			
12	Total for Quarter 3				10,242	2,701	735			
13	October	3,596	6	17	2,612	739	245			
14	November	3,746	21	20	2,802	699	245			
15	December	4,775	6	9	3,650	880	245			
16	Total for Quarter 4				9,064	2,318	735			
17	Total				39,246	9,676	2,910			

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: Enter System									
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-03-18	Year/Period of Report End of: 2024/ Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	18,222,835
3	Steam	14,276,313	23	Requirements Sales for Resale (See instruction 4, page 311.)	353,607
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	958,816
5	Hydro-Conventional	54,234	25	Energy Furnished Without Charge	52
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	28,680
7	Other	4,495,295	27	Total Energy Losses	1,093,192
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	18,825,842	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	20,657,182
10	Purchases (other than for Energy Storage)	1,427,506			
10.1	Purchases for Energy Storage				
11	Power Exchanges:				
12	Received	403,834			
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)	403,834			
15	Transmission For Other (Wheeling)				
16	Received	4,838,343			
17	Delivered	4,838,343			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	20,657,182			

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: Kentucky Utilities Company					
29	January	2,098,854	30,423	4,470	17	9
30	February	1,601,567	743	3,234	19	8
31	March	1,533,214	4,199	2,995	11	8
32	April	1,531,007	96,421	2,656	15	18
33	May	1,592,657	58,961	3,088	21	17
34	June	1,897,776	188,097	3,520	17	15
35	July	2,034,684	205,340	3,565	15	17
36	August	1,984,450	189,896	3,534	6	17
37	September	1,668,631	137,598	3,154	19	17
38	October	1,452,447	15,065	2,680	4	17
39	November	1,462,060	1,798	2,798	21	20
40	December	1,799,835	30,275	3,670	6	8
41	Total	20,657,182	958,816			

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: [a] Brown CT	Plant Name: [b] Cane Run NGCC	Plant Name: EW Brown	Plant Name: Ghent	Plant Name: [c] Haefling	Plant Name: [d] Paddy's Run 13 CT	Plant Name: [e] Trimble County	Plant Name: [f] Trimble County CT
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Combustion Turbine	Combined Cycle	Steam	Steam	Combustion Turbine	Combustion Turbine	[g] Steam	Combustion Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional	Conventional	Conventional	Outdoor	Conventional	Conventional	Conventional
3	Year Originally Constructed	1994	2015	1957	1973	1970	2001	2011	2002
4	Year Last Unit was Installed	2001	2015	1971	1984	1970	2001	2011	2004
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	781.43	630.24	464.00	2,226.06	41.40	83.75	509.09	783.67
6	Net Peak Demand on Plant - MW (60 minutes)	463	543	417	1,930	10	70	467	621
7	Plant Hours Connected to Load	175	5,200	7,745	7,833	2	268	5,354	1,117
8	Net Continuous Plant Capability (Megawatts)	726	516	412	1,919	24	69	445	626
9	When Not Limited by Condenser Water	726	516	412	1,919	24	69	445	626
10	When Limited by Condenser Water	0	0				0		0
11	Average Number of Employees	10	36	85	224	0	1	82	7
12	Net Generation, Exclusive of Plant Use - kWh	118,389,000	3,330,437,000	1,330,472,000	10,543,291,000	(163,000)	36,318,000	2,402,550,000	998,380,000
13	Cost of Plant: Land and Land Rights	333,128	6,243	3,539,910	21,381,408		6,286	1,907,103	26,174
14	Structures and Improvements	13,006,847	51,556,138	96,045,739	240,316,549	291,451	2,205,467	148,406,832	22,616,195
15	Equipment Costs	330,446,854	433,186,751	965,669,137	3,218,732,486	4,106,953	37,909,056	981,084,908	247,498,202
16	Asset Retirement Costs	239,745	69,574	45,687,754	14,335,847		32,134	26,180,212	145,677
17	Total cost (total 13 thru 20)	344,026,574	484,818,706	1,110,942,540	3,494,766,290	4,398,404	40,152,943	1,157,579,055	270,286,248
18	Cost per KW of Installed Capacity (line 17/5) Including	440.2526	769.2604	2,394.2727	1,569.9336	106.2416	479.4381	2,273.8201	344.8980
19	Production Expenses: Oper, Supv, & Engr	184,246	473,555	1,165,280	2,047,060			1,146,463	
20	Fuel	7,069,124	72,833,045	43,398,697	258,415,531	7,141	2,594,414	55,008,332	41,235,803
21	Coolants and Water (Nuclear Plants Only)		0						
22	Steam Expenses		0	5,892,390	5,293,505			(1,343,959)	
23	Steam From Other Sources		0						
24	Steam Transferred (Cr)		0						

Line No.	Item (a)	Plant Name: [a] Brown CT	Plant Name: [b] Cane Run NGCC	Plant Name: EW Brown	Plant Name: Ghent	Plant Name: [c] Haefling	Plant Name: [d] Paddy's Run 13 CT	Plant Name: [e] Trimble County	Plant Name: [f] Trimble County CT
25	Electric Expenses	152,277	5,874,250	1,330,419	5,013,622	150	44,896	1,015,119	828,018
26	Misc Steam (or Nuclear) Power Expenses		0	3,939,555	19,130,748			5,581,704	
27	Rents		0				8,231		
28	Allowances		0	94	1,291				
29	Maintenance Supervision and Engineering	302,590	990,612	2,920,181	7,166,521		21,051	1,319,335	
30	Maintenance of Structures	545,394	629,002	1,529,530	6,107,789			715,604	
31	Maintenance of Boiler (or reactor) Plant		0	7,208,174	25,473,392			4,587,488	
32	Maintenance of Electric Plant	1,174,718	8,929,486	820,375	6,539,388	41,321	403,546	2,888,339	1,020,555
33	Maintenance of Misc Steam (or Nuclear) Plant		0	787,637	1,454,333			739,002	
34	Total Production Expenses	9,428,349	89,729,950	68,992,332	336,643,180	48,612	3,072,138	71,657,427	43,084,376
35	Expenses per Net kWh	0.0796	0.0269	0.0519	0.0319	(0.2982)	0.0846	0.0298	0.0432

35	**Plant Name**	Brown CT	Brown CT	Cane Run NGCC	EW Brown	EW Brown	Ghent	Ghent	Haefling	Paddy's Run 13 CT	Trimble County	Trimble County	Trimble County CT
36	Fuel Kind	Gas	Oil	Gas	Coal	Oil	Coal	Oil	Gas	Gas	Coal	Gas	Gas
37	Fuel Unit	Mcf	bbl	Mcf	T	bbl	T	bbl	Mcf	Mcf	T	Mcf	Mcf
38	Quantity (Units) of Fuel Burned	1,436,317	716	21,000,984	693,288	2,481	4,769,406	16,365	859	375,500	1,423,723	118,402	10,065,138
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,025	3,333	1,065	11,333	3,333	11,991	3,333	1,024	1,065	10,699	1,065	1,065
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5	106	3	65	147	54	117	8	7	50	9	4
41	Average Cost of Fuel per Unit Burned	5	106	3	62	147	54	117	8	7	38	9	4
42	Average Cost of Fuel Burned per Million BTU	5	18	3	3	25	2	20	8	6	2	8	4
43	Average Cost of Fuel Burned per kWh Net Gen		(1)										
44	Average BTU per kWh Net Generation	12,429	(72,559)	6,716	11,811		10,849		(5,399)	11,011	12,680		10,737

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: PlantName

KU owns 47% of Brown CT Unit 5, a 123 MW unit, and 62% of Units 6 and 7, 177 MW each. The remaining percentages of Units 5, 6 and 7 are owned by LG&E. KU also owns 100% of Brown CT Units 8, 9, 10, and 11. Brown CT units 5, 6, 7, 8, 9, 10 and 11 are peak load service units. The information presented here represents KU's share.

(b) Concept: PlantName

KU owns 78% of Cane Run NGCC, a 829 MW unit, with the remaining percentage owned by LG&E. The information presented here represents KU's share.

(c) Concept: PlantName

Haefling turbines are peak load service units.

(d) Concept: PlantName

KU owns 47% of Paddy's Run Unit 13, a 178 MW unit, with the remaining percentage owned by LG&E. Paddy's Run Unit 13 is a peak load service unit. The information presented in here represents KU's share.

(e) Concept: PlantName

Partnership Expenses included in Column d:

Line No.: 19	Production Expenses: Oper, Supv & Engr	$	(382,155)
Line No.: 20	Fuel		(19,523,923)
Line No.: 22	Steam Expenses		417,719
Line No.: 25	Electric Expenses		(338,373)
Line No.: 26	Misc Steam Power Expenses		(1,860,570)
Line No.: 29	Maintenance Supervision and Engineering		(441,491)
Line No.: 30	Maintenance of Structures		(235,551)
Line No.: 31	Maintenance of Boiler Plant		(2,013,768)
Line No.: 32	Maintenance of Electric Plant		(757,940)
Line No.: 33	Maintenance of Misc Steam Plant		(246,334)
Line No.: 34	Total Production Expenses	$	(25,382,387)

Total Power Production Expenses per Schedule Page: 402-403, Sum of Line No.: 34, Columns (Plants): Brown CT, Cane Run NGCC, EW Brown, Ghent, Haefling, Paddy's Run 13 CT, Trimble County, Trimble County CT, Plus IMEA/IMPA Partnership Expenses	$	648,038,751
Operation and Maintenance Expenses on Retired Plants		248,224
Maintenance Expenses on Solar Plant per Schedule Page: 410-411, Column: j		79,407
IMEA-IMPA Partnership Expenses		(25,382,387)
Rounding	$	(1)
Total Power Production Expenses per Schedule Page: 320-321, Sum of Line No.: 21 & 74, Column: b	$	622,983,994

(f) Concept: PlantName

KU owns 71% of Trimble County CT Units 5 and 6 and 63% of Units 7, 8, 9 and 10. The remaining percentages for Units 5, 6, 7, 8, 9 and 10 are owned by LG&E. The total Nameplate Ratings for these units are 199 MW per unit and they are peak load service units. The information presented here represents KU's share.

(g) Concept: PlantKind

KU owns 60.75% of Trimble County Steam Unit 2, a 838 MW unit, with the remaining percentage owned by LG&E, IMEA and IMPA. The information presented here represents KU's share.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Dix Dam
1	Kind of Plant (Run-of-River or Storage)	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional
3	Year Originally Constructed	1923
4	Year Last Unit was Installed	1924
5	Total installed cap (Gen name plate Rating in MW)	33.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	32
7	Plant Hours Connect to Load	2,602
8	**Net Plant Capability (in megawatts)**	
9	(a) Under Most Favorable Oper Conditions	34
10	(b) Under the Most Adverse Oper Conditions	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	54,234,000
13	**Cost of Plant**	
14	Land and Land Rights	855,637
15	Structures and Improvements	4,275,193
16	Reservoirs, Dams, and Waterways	26,779,582
17	Equipment Costs	16,798,259
18	Roads, Railroads, and Bridges	190,033
19	Asset Retirement Costs	863,913
20	Total cost (total 13 thru 20)	49,762,617
21	Cost per KW of Installed Capacity (line 20 / 5)	1,481
22	**Production Expenses**	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Hydraulic Expenses	
26	Electric Expenses	
27	Misc Hydraulic Power Generation Expenses	108,338
28	Rents	

29	Maintenance Supervision and Engineering	15,346
30	Maintenance of Structures	313,970
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	305,587
33	Maintenance of Misc Hydraulic Plant	13,611
34	Total Production Expenses (total 23 thru 33)	756,852
35	Expenses per net kWh	0.0140

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	**Cost of Plant**	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	**Production Expenses**	
24	Operation Supervision and Engineering	
25	Water for Power	

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0
	Page 408-409	

Page 408-409

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
1	Brown Solar	2016	[(a)]6.10	6.2	9,552,000	15,600,084	2,557,391			42,449			
2	Simpsonville Solar	2019	[(b)]1.18	1.2	1,991,000	3,625,091	3,082,560			33,758			
3	Business Solar - Maker's Mark	2020	0.20	0.3	347,000	602,935	3,014,675			3,200			
4	Brown Wind	2023	[(c)]0.06		44,000	700,451	12,160,608						

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: InstalledCapacityOfPlant
The nameplate rating for Brown Photovoltaic Solar Unit represents 61% ownership of the 10 MW unit. The remaining percentage of the unit is owned by LG&E.
(b) Concept: InstalledCapacityOfPlant
The nameplate rating for Simpsonville Solar Array 1-5 represents 56% ownership of the 2.1 MW array. The remaining percentage of the array is owned by LG&E.
(c) Concept: InstalledCapacityOfPlant
The nameplate rating for Brown Wind Unit represents 64% ownership of the 0.9 MW unit. The remaining percentage of the unit is owned by LG&E.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (n) and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self- Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Account for Project Costs (p)
1																
2																
3																
4																
5																
6																
7																
8																
9																
10																
11																
12																
13																
14																
15																
16																
17																
18																
19																
20																
21																
22																
23																
24																
25																
26																
27																
28																
29																
30																
31																
32																
33																
34																

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self- Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Account for Project Costs (p)
35	TOTAL			0	0	0	0	0	0	0	0	0	0	0	0	

Line No.	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35	0	0	0

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR				
					Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
1									
2									
3									
4									
5									
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									

29									
30									
31									
32									
33									
34									
35									
36	TOTAL								

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Pocket	Pineville	500.00	500.00	ST	35.48		[(a)]0	954 mcm	3,117,591	15,708,717	18,826,308
2	Pocket	Phipps Bend	500.00	500.00	ST	21.39		[(b)]0	954 mcm	280,371	8,319,142	8,599,513
3	Ghent Plant	Brown North	345.00	345.00	ST	113.87		[(c)]0	795 mcm	2,495,681	17,718,239	20,213,920
4	Ghent Plant	Batesville	345.00	345.00	ST,SP	7.80		[(d)]0	954 mcm	379,474	6,217,395	6,596,869
5	Brown Plant	Elmer Smith	345.00	345.00	HF,SP,ST	176.42		[(e)]0	954 mcm	17,700,745	109,377,285	127,078,030
6	Brown North	K.U. Park	345.00	345.00	ST	102.47		2	954 mcm	1,111,580	26,077,449	27,189,029
7	Green River	AEC Buss	161.00	161.00	HF,SP,ST,WP	183.09		[(f)]0	556 mcm	1,284,447	44,092,825	45,377,272
8	Green River	Morganfield	161.00	161.00	HF,WP	55.38		[(g)]0	556 mcm	268,660	5,442,527	5,711,187
9	Elihu	Dorchester	161.00	161.00	HF,ST	86.06		[(h)]0	556 mcm	270,147	14,855,250	15,125,397
10	Lake Reba	Dorchester	161.00	161.00	HF,ST	99.15		1	556 mcm	559,988	13,761,966	14,321,954
11	Pineville	Harlan	161.00	161.00	HF,WP	48.34		[(i)]0	795 mcm	300,849	13,597,384	13,898,233
12	Pineville 149	Pineville 192	161.00	161.00	HF	0.12		1	954 mcm		205,543	205,543
13	East Ky. Power Cooperative	Taylor County	161.00	161.00	SP	3.97		1	556 mcm	261,988	630,042	892,030
14	Imboden	Harlan	161.00	161.00	HF,SP,WP,ST	43.82		[(j)]0	795 mcm	84,143	11,352,792	11,436,935
15	Ghent Plant	Brown Plant	138.00	138.00	ST	90.59		[(k)]0	954 mcm	419,701	8,793,404	9,213,105
16	Brown Plant	Green River	138.00	138.00	HF,SP,WP,ST	169.43		[(l)]0	556 mcm	450,190	17,885,724	18,335,914
17	Kenton	Rodburn	138.00	138.00	HF	45.74		1	397 mcm	98,119	19,397,402	19,495,521
18	Green River	Brown North	138.00	138.00	HF,SP,ST	173.88		[(m)]0	795 mcm	736,912	58,070,832	58,807,744
19	Fawkes	Rodburn	138.00	138.00	HF,ST,WP	64.58		1	556 mcm	579,168	20,124,690	20,703,858
20	Clifty Creek	Carrollton	138.00	138.00	HF,SP,ST,WP	144.71		[(n)]0	795 mcm	891,092	57,852,444	58,743,536
21	Brown Plant	Lake Reba	138.00	138.00	HF,SP	29.44		1	556 mcm	80,240	8,457,599	8,537,839
22	Brown Plant	Haefling	138.00	138.00	HF,SP,ST,WP	29.32		[(o)]0	795 mcm	256,943	5,902,673	6,159,616
23	Ghent Plant	Kenton Station	138.00	138.00	HF,WF	72.78		1	795 mcm	446,861	12,612,897	13,059,758
24	Ghent Plant	Adams	138.00	138.00	HF,SP,ST	56.77		[(p)]0	795 mcm	245,501	17,800,851	18,046,352
25	Hardin County	Rogersville	138.00	138.00	HF	10.24		1	795 mcm	245,093	2,569,509	2,814,602
26	Virginia City	Clinch River (AEP Int. Pt)	138.00	138.00	HF	7.89		1	795 mcm	344,980	4,788,455	5,133,435
27	69KV Lines		69.00	69.00	Various	2,194.63		[(q)]0	Various	10,471,878	692,812,489	703,284,367
28	Exp Applicable to All Lines											
36	TOTAL					4,067	0	11		43,382,342	1,214,425,525	1,257,807,867

Line No.	EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28	907,859	8,778,987	273,865	9,960,711
36	907,859	8,778,987	273,865	9,960,711

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(b) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(c) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(d) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(e) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(f) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(g) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(h) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(i) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(j) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(k) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(l) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(m) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(n) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(o) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(p) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.
(q) Concept: NumberOfTransmissionCircuits
Contains both single and double circuitry.

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)	Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	(q)
1																	
2																	
3																	
4																	
5																	
6																	
7																	
8																	
9																	
10																	
11																	
12																	
13																	
14																	
15																	
16																	
17																	
18																	
19																	
20																	
21																	
22																	
23																	
24																	
25																	
26																	

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
27																	
28																	
29																	
30																	
31																	
32																	
33																	
34																	
35																	
36																	
37																	
38																	
39																	
40																	
41																	
42																	
43																	
44	TOTAL		0		0	0	0										

Page 424-425

Page 424-425

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
1	A. O. Smith - Mt. Sterling	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
2	Adams - Georgetown	Transmission	Unattended	138.00	69.00	13.20	187	2	0	NONE	0	0
3	Alcalde - Somerset	Transmission	Unattended	345.00	161.00	13.20	448	1	0	NONE	0	0
4	American Avenue - Lexington	Transmission	Unattended	138.00	69.00	13.20	150	1	0	NONE	0	0
5	Arnold - Cumberland	Transmission	Unattended	161.00	69.00	13.20	56	1	0	NONE	0	0
6	Artemus - Pineville	Transmission	Unattended	161.00	69.00	13.20	56	1	0	NONE	0	0
7	Avon-Fayette	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
8	Bardstown-Campbellsville	Transmission	Unattended	138.00	69.00	13.20	149	1	0	NONE	0	0
9	Bardstown City-Campbellsville	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
10	Bardwell	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
11	Barlow	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
12	Beattyville - Richmond	Transmission	Unattended	161.00	69.00	13.20	90	1	0	NONE	0	0
13	Bevier - Earlington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
14	Bimble	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
15	Blackwell	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
16	Bluegrass Ordnance	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
17	Bond-Coeburn	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
18	Bonds Mill	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
19	Bonnieville - Horse Cave	Transmission	Unattended	138.00	69.00	13.20	33	1	0	NONE	0	0
20	Boone Avenue - Winchester	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
21	Boonesboro North - Winchester	Transmission	Unattended	138.00	69.00	13.20	150	1	0	NONE	0	0
22	Boyle County	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
23	Brodhead Switching	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
24	Bromley	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
25	Brown CT - Harrodsburg	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
26	Brown North - Harrodsburg	Transmission	Unattended	345.00	138.00	13.20	898	2	0	NONE	0	0
27	Brown Plant-Harrodsburg	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
28	Buchanan - Lexington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
29	Camargo - Mt. Sterling	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
30	Campbellsville 1 - Campbellsville	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
31	Carlisle	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
32	Carntown - Augusta	Transmission	Unattended	138.00	69.00	13.20	50	1	0	NONE	0	0
33	Carrollton - Carrollton	Transmission	Unattended	138.00	69.00	13.20	187	2	0	NONE	0	0
34	Cary Switching	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
35	Cawood - Harlan	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
36	Clark County - Winchester	Transmission	Unattended	138.00	69.00	13.20	93	1	0	NONE	0	0
37	Clinton	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
38	Clinton 12kV	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
39	Coleman Road - McCracken Co	Transmission	Unattended	161.00	0.00	0.00	0	0	0	NONE	0	0
40	Corbin East - Corbin	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
41	Corning 12KV	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
42	Corydon - Henderson	Transmission	Unattended	161.00	69.00	13.20	112	1	0	NONE	0	0
43	Crittendon County - Marion	Transmission	Unattended	161.00	69.00	13.20	112	1	0	NONE	0	0
44	Cynthiana	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
45	Danville East - Danville	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
46	Danville Industrial - Danville	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
47	Danville North - Danville	Transmission	Unattended	138.00	69.00	13.20	112	1	0	NONE	0	0
48	Daviess County	Transmission	Unattended	345.00	0.00	0.00	0	0	0	NONE	0	0
49	Delaplain - Georgetown	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
50	Delvinta	Transmission	Unattended	161.00	0.00	0.00	0	0	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
51	Dix Dam-Mercer	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
52	Donerail - Lexington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
53	Dow Corning West	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
54	Dorchester - Norton	Transmission	Unattended	161.00	69.00	13.20	187	2	0	NONE	0	0
55	Earlington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
56	Earlington North - Earlington	Transmission	Unattended	161.00	69.00	13.20	150	1	0	NONE	0	0
57	East Bernstadt - London	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
58	East Frankfort - Frankfort	Transmission	Unattended	138.00	69.00	13.20	224	2	0	NONE	0	0
59	Eastland - Lexington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
60	Eastview	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
61	Elihu - Somerset	Transmission	Unattended	161.00	69.00	13.20	187	2	0	NONE	0	0
62	Elizabethtown - Elizabethtown	Transmission	Unattended	138.00	69.00	13.20	149	1	0	NONE	0	0
63	Elizabethtown 5 - Elizabethtown	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
64	Eminence	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
65	Evarts	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
66	Fariston	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
67	Farley - Corbin	Transmission	Unattended	161.00	69.00	13.20	149	1	0	NONE	0	0
68	Farmers - Morehead	Transmission	Unattended	138.00	69.00	13.20	61	1	0	NONE	0	0
69	Fawkes - Richmond	Transmission	Unattended	138.00	69.00	13.20	299	2	0	NONE	0	0
70	Finchville	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
71	FMC - Lexington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
72	Frankfort - Frankfort	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
73	GE Lamp Works - Lexington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
74	Georgetown - Georgetown	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
75	Ghent Plant - Carrollton 1	Transmission	Unattended	345.00	138.00	0.00	450	1	0	NONE	0	0
76	Ghent Plant - Carrollton 2	Transmission	Unattended	345.00	138.00	25.00	448	1	0	NONE	0	0
77	Glendale Industrial	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
78	Glendale South	Transmission	Unattended	345.00	138.00	13.80	900	2	0	NONE	0	0
79	Goddard	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
80	Gorge Switching	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
81	Grahamville - Barlow	Transmission	Unattended	161.00	69.00	13.20	93	1	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
82	Green River Plant - Greenville 1	Transmission	Unattended	138.00	69.00	13.20	261	2	0	NONE	0	0
83	Green River Plant - Greenville 2	Transmission	Unattended	161.00	138.00	13.20	312	3	1	NONE	0	0
84	Green River Steel - Greenville	Transmission	Unattended	138.00	69.00	13.80	90	1	0	NONE	0	0
85	Greensburg - Campellsville	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
86	Haefling - Lexington	Transmission	Unattended	138.00	69.00	13.20	149	1	0	NONE	0	0
87	Hardesty - Earlington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
88	Hardin County - Elizabethtown 1	Transmission	Unattended	345.00	138.00	13.20	898	2	0	NONE	0	0
89	Hardin County - Elizabethtown 2	Transmission	Unattended	138.00	69.00	13.20	370	2	0	NONE	0	0
90	Hardinsburg - Hardinsburg	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
91	Harrodsburg	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
92	Harlan "Y" - Harlan	Transmission	Unattended	161.00	69.00	13.20	93	1	0	NONE	0	0
93	Higby Mill - Lexington	Transmission	Unattended	138.00	69.00	13.20	344	3	0	NONE	0	0
94	Hillside	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
95	Hodgenville	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
96	Hoover 1- Georgetown	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
97	Howards Branch	Transmission	Unattended	161.00	0.00	0.00	0	0	0	NONE	0	0
98	Hughes Lane - Lexington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
99	Hume Road	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
100	IBM	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
101	Imboden - Big Stone Gap	Transmission	Unattended	161.00	69.00	13.20	149	1	0	NONE	0	0
102	Indian Hill	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
103	Innovation Drive	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
104	Kenton - Maysville	Transmission	Unattended	138.00	69.00	13.20	145	2	0	NONE	0	0
105	Kentucky River	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
106	KU Park - Pineville	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
107	LaGrange East	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
108	Lancaster 2	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
109	Lake Reba - Richmond	Transmission	Unattended	138.00	69.00	13.20	149	1	0	NONE	0	0
110	Lake Reba Tap - Richmond	Transmission	Unattended	161.00	138.00	6.60	200	1	0	NONE	0	0
111	Lancaster Switching	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
112	Lansdowne - Lexington	Transmission	Unattended	138.00	69.00	13.20	112	1	0	NONE	0	0
113	Lawrence	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
114	Lebanon - Lebanon	Transmission	Unattended	138.00	69.00	13.20	93	1	0	NONE	0	0
115	Lebanon City	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
116	Leitchfield - Leitchfield	Transmission	Unattended	138.00	69.00	13.20	93	1	0	NONE	0	0
117	Leitchfield East	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
118	Lexington Plant - Lexington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
119	Livingston County	Transmission	Unattended	161.00	0.00	0.00	0	0	0	NONE	0	0
120	Lockport	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
121	London - London	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
122	Loudon Ave - Lexington	Transmission	Unattended	138.00	69.00	13.20	262	2	2	NONE	0	0
123	Lynch - Harlan	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
124	Lyon County	Transmission	Unattended	161.00	0.00	0.00	0	0	0	NONE	0	0
125	Manchester	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
126	Marion	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
127	Matanzas	Transmission	Unattended	161.00	138.00	13.20	400	2	0	NONE	0	0
128	Meldrum SW	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
129	Meredith	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
130	Middlesboro - Middlesboro	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
131	Midway - Versailles	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
132	Mill Creek	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
133	Millersburg - Millersburg	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
134	Morehead	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
135	Morehead East - Morehead	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
136	Morganfield - Morganfield	Transmission	Unattended	161.00	69.00	13.20	112	1	0	NONE	0	0
137	Mt. Vernon - Mt. Vernon	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
138	N.A.S.	Transmission	Unattended	345.00	138.00	0.00	450	1	0	NONE	0	0
139	Nebo - Nebo	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
140	Newtown	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
141	Nicholasville	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
142	North London -London	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
143	North Princeton - Princeton	Transmission	Unattended	161.00	0.00	0.00	0	0	0	NONE	0	0
144	Oak Hill	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
145	Ohio County - Beaver Dam	Transmission	Unattended	138.00	69.00	13.20	93	1	0	NONE	0	0
146	Okonite - Richmond	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
147	Paducah Primary - Paducah	Transmission	Unattended	161.00	0.00	0.00	0	0	0	NONE	0	0
148	Paint Lick	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
149	Paris	Transmission	Unattended	138.00	69.00	13.20	150	1	0	NONE	0	0
150	Paris 12kV	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
151	Parkers Mill	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
152	Paynes Mill	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
153	Pineville - Pineville 1	Transmission	Unattended	345.00	161.00	13.20	560	1	0	NONE	0	0
154	Pineville - Pineville 2	Transmission	Unattended	500.00	345.00	34.50	504	1	0	NONE	0	0
155	Pineville - Pineville 3	Transmission	Unattended	161.00	69.00	13.20	299	2	1	NONE	0	0
156	Pineville Switching - Pineville	Transmission	Unattended	161.00	0.00	0.00	0	0	0	NONE	0	0
157	Pisgah - Lexington	Transmission	Unattended	138.00	69.00	13.20	112	1	0	NONE	0	0
158	Pittsburg - London	Transmission	Unattended	161.00	69.00	13.20	112	1	0	NONE	0	0
159	Pocket - Pennington Gap	Transmission	Unattended	161.00	69.00	13.20	187	1	0	NONE	0	0
160	Pocket North - Pennington Gap	Transmission	Unattended	500.00	161.00	0.00	448	1	0	NONE	0	0
161	Princeton - Princeton	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
162	Race Street - Lexington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
163	Reynolds - Lexington	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
164	Richmond - Richmond	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
165	Richmond 3 (EKU)	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
166	Richmond 4	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
167	Richmond North	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
168	River Queen - Muhlenberg	Transmission	Unattended	161.00	69.00	13.20	112	1	0	NONE	0	0
169	Robbins	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
170	Rockwell - Winchester	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
171	Rocky Branch	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
172	Rodburn - Morehead	Transmission	Unattended	138.00	69.00	13.20	90	1	0	NONE	0	0
173	Rogersville - Radcliff	Transmission	Unattended	138.00	69.00	13.20	93	1	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
174	Rumsey	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
175	Scott County	Transmission	Unattended	138.00	69.00	13.20	93	1	0	NONE	0	0
176	Shadrack	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
177	Sharon	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
178	Shawnee Gas	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
179	Shelbyville - Shelbyville	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
180	Shrewsbury Sw	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
181	Simmons	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
182	Simpsonville - Shelbyville	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
183	Somerset N - Somerset	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
184	Somerset 1	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
185	South Paducah	Transmission	Unattended	161.00	69.00	13.20	50	1	0	NONE	0	0
186	Spears SW	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
187	Spencer Road - Mt. Sterling	Transmission	Unattended	138.00	69.00	13.20	89	2	0	NONE	0	0
188	Springfield - Campbellsville	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
189	St. Paul	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
190	Stanford	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
191	Stanford North	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
192	Stonewall - Lexington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
193	Sweet Hollow	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
194	Taylor County - Campellsville	Transmission	Unattended	161.00	69.00	13.20	90	1	0	NONE	0	0
195	Toyota North	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
196	Toyota South	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
197	Tyrone - Versailles	Transmission	Unattended	138.00	69.00	13.20	112	1	0	NONE	0	0
198	UK Medical Center - Lexington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
199	Viley Road - Lexington	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
200	Virginia City - Norton	Transmission	Unattended	138.00	69.00	13.20	120	1	0	NONE	0	0
201	Walker - Earlington	Transmission	Unattended	161.00	69.00	13.20	112	1	0	NONE	0	0
202	Warsaw	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
203	Warsaw East - Owenton	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
204	West Cliff - Harrodsburg	Transmission	Unattended	138.00	69.00	13.20	392	3	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
205	West Frankfort - Shelbyville 1	Transmission	Unattended	345.00	138.00	13.20	450	1	0	NONE	0	0
206	West Frankfort - Shelbyville 2	Transmission	Unattended	138.00	69.00	13.20	112	1	0	NONE	0	0
207	West Garrard - Lancaster	Transmission	Unattended	345.00	0.00	0.00	0	0	0	NONE	0	0
208	West Hickman - Lexington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
209	West Irvine - Irvine	Transmission	Unattended	161.00	69.00	13.20	56	1	0	NONE	0	0
210	West Lexington - Lexington	Transmission	Unattended	345.00	138.00	13.20	448	1	0	NONE	0	0
211	West Shelby	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
212	Wheatcroft	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
213	White Sulphur	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
214	Wickliffe - Barlow	Transmission	Unattended	161.00	69.00	13.20	93	1	0	NONE	0	0
215	Williamsburg Switching	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
216	Wilson Downing - Lexington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
217	Winchester	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
218	Wofford	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
219	Total Transmission			25,909.00	6,279.00	938.50	15839	94	4		0	0
220	A.O. Smith - Mt. Sterling	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
221	Adams 1	Distribution	Unattended	69.00	34.50	0.00	20	1	0	NONE	0	0
222	Adams 2	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
223	Airgas	Distribution	Unattended	138.00	13.80	0.00	22	1	0	NONE	0	0
224	Aisin	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
225	Alexander - Versailles	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
226	American Avenue - Lexington	Distribution	Unattended	69.00	12.47	0.00	36	2	0	NONE	0	0
227	Andover - Norton	Distribution	Unattended	69.00	34.50	0.00	22	1	0	NONE	0	0
228	Appalachia	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE		
229	Ashland Avenue - Lexington	Distribution	Unattended	69.00	4.16	0.00	28	2	0	NONE	0	0
230	Ashland Pipe - Lexington	Distribution	Unattended	69.00	12.47	0.00	20	2	0	NONE	0	0
231	Atoka	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
232	Augusta 12KV	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
233	Bardstown City	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
234	Bardstown Industrial	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
235	Barlow	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
236	Barton-Bardstown	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
237	Beaver Dam - Beaver Dam	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
238	Beaver Dam North - Beaver Dam	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
239	Belt Line - Lexington	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
240	Bevier - Earlington	Distribution	Unattended	69.00	34.50	0.00	14	2	0	NONE	0	0
241	Big Stone Gap - Big Stone Gap	Distribution	Unattended	69.00	12.47	0.00	42	3	0	NONE	0	0
242	Black Branch Road	Distribution	Unattended	138.00	12.47	0.00	28	1	0	NONE	0	0
243	Bond - Coeburn 1	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
244	Bond - Coeburn 2	Distribution	Unattended	69.00	23.00	0.00	22	1	0	NONE	0	0
245	Boone Avenue - Winchester	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
246	Boonesboro Park	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
247	Borg Warner - Earlington	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
248	Bryant Road - Lexington	Distribution	Unattended	69.00	12.47	0.00	67	3	0	NONE	0	0
249	Buchanan - Lexington	Distribution	Unattended	69.00	4.16	0.00	14	1	0	NONE	0	0
250	Buena Vista	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
251	Burnside - Somerset	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
252	Calloway	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
253	Camargo - Mt. Sterling	Distribution	Unattended	69.00	12.47	0.00	75	2	0	NONE	0	0
254	Camp Breckinridge	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
255	Campbellsville 1 - Campbellsville	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
256	Campbellsville Industrial - Campbellsville	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
257	Carlisle	Distribution	Unattended	69.00	12.47	0.00	14	2	0	NONE	0	0
258	Carntown - Augusta	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
259	Caron - London	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
260	Carrollton - Carrollton	Distribution	Unattended	69.00	12.47	0.00	19	2	0	NONE	0	0
261	Catrons Creek	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
262	Cawood - Harlan	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
263	Central City	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
264	Central City South	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
265	Clarkson	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
266	Clays Mill - Lexington	Distribution	Unattended	138.00	12.47	0.00	37	1	0	NONE	0	0
267	Clinch Valley - Norton	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
268	Clinton	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
269	Columbia - Columbia	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
270	Columbia South - Columbia	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
271	Corbin East - Corbin	Distribution	Unattended	69.00	12.47	0.00	36	2	0	NONE	0	0
272	Corbin US Steel	Distribution	Unattended	69.00	12.47	0.00	25	2	0	NONE	0	0
273	Corning 12KV	Distribution	Unattended	69.00	12.47	0.00	56	2	0	NONE	0	0
274	Corning Harrodsburg	Distribution	Unattended	69.00	12.47	0.00	15	7	0	NONE	0	0
275	Corporate Drive	Distribution	Unattended	69.00	12.47	0.00	60	2	0	NONE	0	0
276	Cynthiana	Distribution	Unattended	69.00	12.47	0.00	20	2	0	NONE	0	0
277	Cynthiana South	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
278	Danville Central - Danville	Distribution	Unattended	69.00	12.47	0.00	29	2	0	NONE	0	0
279	Danville East - Danville	Distribution	Unattended	69.00	12.47	0.00	29	2	0	NONE	0	0
280	Danville Industrial - Danville	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
281	Danville North - Danville	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
282	Danville West - Danville	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
283	Dark Hollow - Richmond	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
284	Dayhoit	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
285	Days Branch	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
286	Dayton - Walther - Carrollton	Distribution	Unattended	138.00	12.47	0.00	14	1	0	NONE	0	0
287	Delaplain - Georgetown 1	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
288	Delaplain - Georgetown 2	Distribution	Unattended	69.00	13.80	0.00	28	1	0	NONE	0	0
289	Denham Street - Somerset	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
290	Detroit Harvester - Paris	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
291	Donerail - Lexington	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
292	Dorchester - Norton 1	Distribution	Unattended	69.00	22.00	0.00	25	1	0	NONE	0	0
293	Dorchester - Norton 2	Distribution	Unattended	69.00	34.50	0.00	14	1	0	NONE	0	0
294	Dorchester - Norton 3	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
295	Dow Corning - Carrollton	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
296	Dozier Heights	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
297	Earlington - Earlington 1	Distribution	Unattended	69.00	34.50	0.00	20	1	0	NONE	0	0
298	Earlington - Earlington 2	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
299	East Bernstadt - London	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
300	East Stone Gap- Big Stone Gap	Distribution	Unattended	69.00	12.47	0.00	25	2	0	NONE	0	0
301	Eastland - Lexington	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
302	Eastview	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
303	Eddyville	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
304	Eddyville Prison	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
305	Elizabethtown Industrial - Elizabethtown	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
306	Eminence - Shelbyville	Distribution	Unattended	69.00	12.47	0.00	28	2	0	NONE	0	0
307	Esserville - Norton	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
308	Elizabethtown 2 - Elizabethtown	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
309	Elizabethtown 3 - Elizabethtown	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
310	Elizabethtown 4 - Elizabethtown	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
311	Elizabethtown 5 - Elizabethtown	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
312	Elizabethtown West - Elizabethtown	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
313	Evarts	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
314	Ewington - Mt. Sterling	Distribution	Unattended	69.00	12.47	0.00	36	2	0	NONE	0	0
315	Fairfield - Fairfield	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
316	Farmers	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
317	Ferguson South - Somerset	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
318	Finchville	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
319	Flemingsburg	Distribution	Unattended	138.00	12.47	0.00	14	1	0	NONE	0	0
320	Florida Tile - Lawrenceburg	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
321	FMC - Lexington	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
322	Forrestdale	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
323	Forks of Elkhorn - Georgetown	Distribution	Unattended	34.50	12.47	0.00	14	1	0	NONE	0	0
324	Frankfort - Frankfort	Distribution	Unattended	69.00	34.50	0.00	22	1	0	NONE	0	0
325	GE Lamp Works - Lexington	Distribution	Unattended	69.00	4.16	0.00	14	1	0	NONE	0	0
326	Georgetown - Georgetown	Distribution	Unattended	69.00	12.47	0.00	21	2	0	NONE	0	0
327	Ghent City	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
328	Ghent Plant	Distribution	Unattended	138.00	13.20	0.00	56	2	0	NONE	0	0
329	Glendale Temporary Construction	Distribution	Unattended	69.00	12.47	0.00	37	1	0	NONE	0	0
330	Glendale Industrial	Distribution	Unattended	138.00	24.70	0.00	540	6	0	NONE	0	0
331	Green River Steel	Distribution	Unattended	69.00	12.47	0.00	25	2	0	NONE	0	0
332	Green River	Distribution	Unattended	69.00	34.50	0.00	17	1	0	NONE	0	0
333	Greensburg - Campellsville	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
334	Greenville 12KV - Muhlenburg	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
335	Greenville 4KV - Muhlenburg	Distribution	Unattended	69.00	4.16	0.00	11	1	0	NONE	0	0
336	Greenville North - Muhlenburg	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
337	Guest River - Ramsey, VA	Distribution	Unattended	23.00	4.16	0.00	11	3	0	NONE	0	0
338	Haefling - Lexington	Distribution	Unattended	138.00	12.47	0.00	39	1	0	NONE	0	0
339	Haley - Lexington	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
340	Hamblin - Pennington Gap	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
341	Hamer- Appalachia	Distribution	Unattended	69.00	12.47	0.00	16	2	0	NONE	0	0
342	Hanson - Earlington	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
343	Hardesty - Earlington	Distribution	Unattended	69.00	34.50	0.00	13	1	0	NONE	0	0
344	Harlan - Harlan	Distribution	Unattended	69.00	12.47	0.00	21	2	0	NONE	0	0
345	Harlan Wye - Harlan	Distribution	Unattended	69.00	12.47	0.00	28	2	0	NONE	0	0
346	Harrodsburg East - Harrodsburg	Distribution	Unattended	69.00	12.47	0.00	20	2	0	NONE	0	0
347	Harrodsburg Industrial - Harrodsburg	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
348	Harrodsburg North	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
349	Hartford	Distribution	Unattended	69.00	4.16	0.00	11	1	0	NONE	0	0
350	Higby Mill - Lexington 1	Distribution	Unattended	138.00	12.47	0.00	37	1	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
351	Higby Mill - Lexington 2	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
352	Highsplint - Harlan	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
353	Hodgenville 12KV	Distribution	Unattended	69.00	12.47	0.00	19	2	0	NONE	0	0
354	Hoover 1- Georgetown	Distribution	Unattended	69.00	12.47	0.00	75	2	0	NONE	0	0
355	Hopewell - Corbin	Distribution	Unattended	69.00	12.47	0.00	36	2	0	NONE	0	0
356	Horse Cave	Distribution	Unattended	69.00	12.47	0.00	28	2	0	NONE	0	0
357	Horse Cave Industrial - Horse Cave	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
358	Hughes Lane - Lexington	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
359	Hume Road	Distribution	Unattended	69.00	12.47	0.00	60	2	2	NONE	0	0
360	IBM - Lexington	Distribution	Unattended	69.00	12.47	0.00	75	2	0	NONE	0	0
361	IBM North	Distribution	Unattended	138.00	12.47	0.00	27	1	0	NONE	0	0
362	Innovation Drive	Distribution	Unattended	138.00	12.47	0.00	75	2	0	NONE	0	0
363	Irvine - Richmond	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
364	Joyland - Lexington	Distribution	Unattended	69.00	12.47	0.00	36	2	0	NONE	0	0
365	Kawneer - Cynthiana	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
366	Kentenia	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
367	Kenton - Maysville	Distribution	Unattended	69.00	12.47	0.00	28	2	1	NONE	0	0
368	Kentucky State Hospital	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
369	Kentucky River	Distribution	Unattended	69.00	4.16	0.00	35	3	0	NONE	0	0
370	LaGrange East	Distribution	Unattended	69.00	12.47	0.00	36	2	0	NONE	0	0
371	LaGrange Penal - LaGrange	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
372	Lakeshore - Lexington	Distribution	Unattended	69.00	12.47	0.00	75	2	0	NONE	0	0
373	Lancaster - Danville	Distribution	Unattended	69.00	4.16	0.00	14	1	0	NONE	0	0
374	Lansdowne - Lexington	Distribution	Unattended	69.00	12.47	0.00	75	2	0	NONE	0	0
375	Lawrenceburg - Lawrenceburg	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
376	Lebanon - Lebanon	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
377	Lebanon East	Distribution	Unattended	69.00	12.47	0.00	28	2	0	NONE	0	0
378	Lebanon Industrial	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
379	Lebanon South - Lebanon	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
380	Lebanon Junction	Distribution	Unattended	161.00	12.47	0.00	45	2	0	NONE	0	0
381	Lebanon West	Distribution	Unattended	138.00	12.47	0.00	14	1	0	NONE	0	0
382	Leitchfield - Leitchfield	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
383	Leitchfield East - Leitchfield	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
384	Lemons Mill - Georgetown	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
385	Lexington Water Company 1	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
386	Lexington Water Company 2	Distribution	Unattended	69.00	4.16	0.00	11	1	0	NONE	0	0
387	Lexington Plant - Lexington	Distribution	Unattended	69.00	4.16	0.00	28	2	0	NONE	0	0
388	Liberty - Liberty	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
389	Liberty Road - Lexington	Distribution	Unattended	69.00	12.47	0.00	37	1	0	NONE	0	0
390	Liggett	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
391	Lockport	Distribution	Unattended	138.00	12.47	0.00	11	1	0	NONE	0	0
392	London - London	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
393	Loudon Avenue - Lexington	Distribution	Unattended	138.00	12.47	0.00	37	1	0	NONE	0	0
394	Manchester South	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
395	Marion South - Marion	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
396	Maysville East - Maysville	Distribution	Unattended	69.00	4.16	0.00	11	1	0	NONE	0	0
397	Maysville Mid - Maysville	Distribution	Unattended	69.00	4.16	0.00	14	1	0	NONE	0	0
398	McKee Road	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
399	Meldrum - Middlesboro	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
400	Metal & Thermit - Carrollton	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
401	Middlesboro #1	Distribution	Unattended	69.00	12.47	0.00	75	2	0	NONE	0	0
402	Middlesboro #2	Distribution	Unattended	69.00	12.47	0.00	28	2	0	NONE	0	0
403	Midway - Versailles	Distribution	Unattended	138.00	12.47	0.00	14	1	0	NONE	0	0
404	Mill Creek	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
405	Minor Farm	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
406	Morehead - Morehead 1	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
407	Morehead - Morehead 2	Distribution	Unattended	69.00	4.16	0.00	11	1	0	NONE	0	0
408	Morehead East - Morehead	Distribution	Unattended	69.00	4.16	0.00	11	1	0	NONE	0	0
409	Morehead West - Morehead	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
410	Morganfield City - Morganfield	Distribution	Unattended	69.00	4.16	0.00	11	1	0	NONE	0	0
411	Morganfield Industrial - Morganfield	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
412	Mount Sterling - Mt. Sterling	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
413	Mount Vernon - Mt. Vernon	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
414	Mount Vernon Tap- Mt Vernon	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
415	Muhlenburg Prison - Muhlenburg	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
416	Munfordville	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
417	New Haven	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
418	Newtown	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
419	Norton East - Norton	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
420	Nortonville	Distribution	Unattended	34.50	12.47	0.00	14	1	0	NONE	0	0
421	Oakhill - Earlington	Distribution	Unattended	69.00	34.50	0.00	20	1	0	NONE	0	0
422	Okonite - Richmond	Distribution	Unattended	69.00	12.47	0.00	36	2	0	NONE	0	0
423	Owingsville	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
424	Oxford - Georgetown	Distribution	Unattended	69.00	12.47	0.00	28	2	0	NONE	0	0
425	Paris - Paris	Distribution	Unattended	69.00	12.47	0.00	28	2	0	NONE	0	0
426	Parker Seal - Winchester	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
427	Parkers Mill	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
428	Paynes Mill- Versailles	Distribution	Unattended	69.00	12.47	0.00	37	1	0	NONE	0	0
429	Pepper Pike - Georgetown	Distribution	Unattended	34.50	12.47	0.00	14	1	0	NONE	0	0
430	Picadome - Lexington	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
431	Pineville	Distribution	Unattended	69.00	12.47	0.00	28	2	0	NONE	0	0
432	Pocket - Norton	Distribution	Unattended	69.00	34.50	0.00	25	4	0	NONE	0	0
433	Poor Valley - Pennington Gap	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
434	Powderly - Muhlenburg	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
435	Princeton - Princeton	Distribution	Unattended	69.00	34.50	0.00	13	1	0	NONE	0	0
436	Proctor & Gamble	Distribution	Unattended	69.00	4.16	0.00	14	1	0	NONE	0	0
437	Race Street - Lexington 1	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
438	Race Street - Lexington 2	Distribution	Unattended	69.00	4.16	0.00	21	2	0	NONE	0	0
439	Radcliff - Radcliff	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
440	Radcliff South- Radcliff	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
441	Red House	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
442	Reynolds - Lexington	Distribution	Unattended	138.00	12.47	0.00	77	2	0	NONE	0	0
443	Richmond	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
444	Richmond 2	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
445	Richmond 3 (EKU)	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
446	Richmond East	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
447	Richmond Industrial	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
448	Richmond South	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
449	Richmond North	Distribution	Unattended	138.00	12.47	0.00	37	1	0	NONE	0	0
450	Rineyville	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
451	Robbins	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
452	Rockwell - Winchester	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
453	Rogers Gap-Georgetown 1	Distribution	Unattended	138.00	12.47	0.00	28	1	0	NONE	0	0
454	Rogers Gap-Georgetown 2	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
455	Rogersville - Radcliff	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
456	Rose Hill	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
457	Rumsey - Earlington	Distribution	Unattended	69.00	34.50	0.00	13	1	0	NONE	0	0
458	Russell Springs	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
459	Salem - Earlington	Distribution	Unattended	69.00	34.50	0.00	14	1	0	NONE	0	0
460	Shadrack	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
461	Shannon Run	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
462	Sharon - Augusta	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
463	Shavers Chapel	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
464	Shawnee Gas	Distribution	Unattended	69.00	12.47	0.00	15	1	0	NONE	0	0
465	Shelbyville North	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
466	Shelbyville East	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
467	Shelbyville South	Distribution	Unattended	69.00	12.47	0.00	36	2	0	NONE	0	0
468	Shun Pike	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
469	Simpsonville - Shelbyville	Distribution	Unattended	69.00	12.47	0.00	25	2	0	NONE	0	0
470	Somerset 2	Distribution	Unattended	69.00	4.16	0.00	11	1	0	NONE	0	0
471	Somerset 3	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
472	Somerset South	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
473	Sonora	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
474	Springfield - Campbellsville	Distribution	Unattended	69.00	12.47	0.00	25	2	0	NONE	0	0
475	St. Paul	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
476	Stamping Ground	Distribution	Unattended	34.50	12.47	0.00	14	1	0	NONE	0	0
477	Stanford	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
478	Stanford North	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
479	Stonewall - Lexington	Distribution	Unattended	69.00	12.47	0.00	75	2	0	NONE	0	0
480	Sylvania - Winchester	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
481	Taylorsville - Shelbyville	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
482	Toms Creek	Distribution	Unattended	69.00	4.16	0.00	11	1	0	NONE	0	0
483	Totz	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
484	Toyota North	Distribution	Unattended	138.00	13.20	0.00	84	3	1	NONE	0	0
485	Toyota South	Distribution	Unattended	138.00	13.20	0.00	112	4	0	NONE	0	0
486	Trafton Avenue - Lexington 1	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
487	Trafton Avenue - Lexington 2	Distribution	Unattended	69.00	4.16	0.00	14	1	0	NONE	0	0
488	UK Scott Street	Distribution	Unattended	69.00	12.47	0.00	37	1	0	NONE	0	0
489	UK Medical Center - Lexington	Distribution	Unattended	69.00	12.47	0.00	75	2	0	NONE	0	0
490	UK West - Lexington	Distribution	Unattended	69.00	13.09	0.00	42	2	0	NONE	0	0
491	Union Underwear - Russell Springs	Distribution	Unattended	69.00	12.47	0.00	28	2	0	NONE	0	0
492	Uniontown	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
493	Vaksdahl Avenue	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
494	Verda - Harlan	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
495	Versailles West - Versailles	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
496	Versailles Bypass - Versailles	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
497	Viley Road - Lexington	Distribution	Unattended	138.00	12.47	0.00	77	2	0	NONE	0	0
498	Vine Street - Lexington	Distribution	Unattended	69.00	12.47	0.00	20	2	0	NONE	0	0
499	Waco	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
500	Waitsboro - Somerset	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
501	Warsaw East - Owenton	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
502	West Hickman - Lexington	Distribution	Unattended	69.00	12.47	0.00	45	2	0	NONE	0	0
503	West High Street - Lexington	Distribution	Unattended	69.00	12.47	0.00	75	2	0	NONE	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
504	West Shelby	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
505	Westvaco	Distribution	Unattended	69.00	13.80	0.00	67	3	0	NONE	0	0
506	White Sulphur-Georgetown	Distribution	Unattended	138.00	12.47	0.00	37	1	0	NONE	0	0
507	Whitley	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
508	Wickliffe	Distribution	Unattended	69.00	13.80	0.00	14	1	0	NONE	0	0
509	Wilson Downing - Lexington	Distribution	Unattended	69.00	12.47	0.00	75	2	0	NONE	0	0
510	Williamsburg South - Williamsburg	Distribution	Unattended	69.00	12.47	0.00	25	2	0	NONE	0	0
511	Wilmore - Versailles	Distribution	Unattended	69.00	12.47	0.00	18	2	0	NONE	0	0
512	Winchester Industrial - Winchester	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
513	Winchester Water	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
514	Wise - Norton	Distribution	Unattended	69.00	12.47	0.00	22	1	0	NONE	0	0
515	Woodlawn	Distribution	Unattended	69.00	12.47	0.00	14	1	0	NONE	0	0
516	177 Stations Less Than 10,000 KVA	Distribution	Unattended	0.00	0.00	0.00	796	222	122	NONE	0	0
517	Total Distribution			21,850.00	3,851.73	0.00	8464	625	126		0	0
518				0.00	0.00	0.00	0	0	0		0	0
519	* Unattended			0.00	0.00	0.00	0	0	0		0	0
520	Summary			0.00	0.00	0.00	0	0	0		0	0
521	Transmission 215			0.00	0.00	0.00	15839	94	6		0	0
522	Distribution 461			0.00	0.00	0.00	8464	625	126		0	0
523	Total 676 - 133 shared = 543			0.00	0.00	0.00	24303	719	132		0	0
524	Shared 133			0.00	0.00	0.00	0	0	0		0	0
525	Total											0

Page 426-427

Page 426-427

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Capital Expenditures	Louisville Gas and Electric Company	see footnote [(a)]	154,140,198
3	Direct-Indirect Labor	Louisville Gas and Electric Company	see footnote [(b)]	21,593,537
4	Equipment and Facilities	Louisville Gas and Electric Company	see footnote [(c)]	711,436
5	Materials and Fuels	Louisville Gas and Electric Company	see footnote [(d)]	91,508
6	Office and Administrative Services	Louisville Gas and Electric Company	see footnote [(e)]	68,633
7	Outside Services	Louisville Gas and Electric Company	see footnote [(f)]	214,279
8	Transmission	Louisville Gas and Electric Company	see footnote [(g)]	836,682
9	Capital Expenditures	LG&E and KU Services Company	see footnote [(h)]	25,279,247
10	Direct-Indirect Labor	LG&E and KU Services Company	see footnote [(i)]	72,958,032
11	Equipment and Facilities	LG&E and KU Services Company	see footnote [(j)]	13,172,017
12	Materials	LG&E and KU Services Company	see footnote [(k)]	973,156
13	Office and Administrative Services	LG&E and KU Services Company	see footnote [(l)]	3,942,212
14	Outside Services	LG&E and KU Services Company	see footnote [(m)]	13,817,285
15	Capital Expenditures	PPL Services Corporation	see footnote [(n)]	17,808,609
16	Direct-Indirect Labor	PPL Services Corporation	see footnote [(o)]	26,549,076
17	Equipment and Facilities	PPL Services Corporation	see footnote [(p)]	1,246,456
18	Materials	PPL Services Corporation	see footnote [(q)]	12,018
19	Office and Administrative Services	PPL Services Corporation	see footnote [(r)]	3,829,079
20	Outside Services	PPL Services Corporation	see footnote [(s)]	14,902,857
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Capital Expenditures	Louisville Gas and Electric Company	see footnote [(u)]	4,636,737
22	Direct-Indirect Labor	Louisville Gas and Electric Company	see footnote [(v)]	[(ai)]1,561,025

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
23	Equipment and Facilities	Louisville Gas and Electric Company	[w] see footnote	1,536,880
24	Materials and Fuels	Louisville Gas and Electric Company	[x] see footnote	40,775
25	Office and Administrative Services	Louisville Gas and Electric Company	[y] see footnote	153,947
26	Outside Services	Louisville Gas and Electric Company	[z] see footnote	495,747
27	Transmission	Louisville Gas and Electric Company	[aa] see footnote	548,568
28	Capital Expenditures	LG&E and KU Services Company	[ab] see footnote	315,309
29	Direct-Indirect Labor	LG&E and KU Services Company	[ac] see footnote	[am]2,055,082
30	Equipment and Facilities	LG&E and KU Services Company	[ad] see footnote	292,147
31	Materials	LG&E and KU Services Company	[ae] see footnote	5,102
32	Office and Administrative Services	LG&E and KU Services Company	[af] see footnote	41,362
33	Outside Services	LG&E and KU Services Company	[ag] see footnote	132,206
34	Capital Expenditures	PPL Services Corporation		
35	Direct-Indirect Labor	PPL Services Corporation	[ah] see footnote	2,737
36	Equipment and Facilities	PPL Services Corporation	[ai] see footnote	1,617,227
37	Office and Administrative Services	PPL Services Corporation	[aj] see footnote	1,696
38	Outside Services	PPL Services Corporation	[ak] see footnote	48,228
39	[t] See footnote for allocation process			
42				

Page 429

Name of Respondent: Kentucky Utilities Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/18/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 107 and 108

(b) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 182.3, 183.2, 184, 408.1, 426.4, 426.5, 500, 501, 502, 505, 506, 510, 511, 512, 513, 514, 546, 548, 549, 551, 552, 553, 554, 560, 562, 571, 580, 583, 588, 593, 597, 598, 901, 903, 908, 920, 925, 926, and 935

(c) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 163, 183.2, 184, 426.4, 426.5, 454, 493, 500, 501, 506, 510, 553, 560, 562, 566, 570, 571, 580, 582, 583, 586, 588, 590, 592, 593, 597, 901, 902, 903, 921, 931, and 935

(d) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 163, 426.4, 426.5, 506, 511-514, 553, 563, 570, 571, 580, 582, 586, 590, 592, 593, 597, 598, 902, and 921

(e) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 184, 426.4, 426.5, 500, 506, 510, 560, 571, 580, 586, 588, 593, 598, 901, 902, 908, 921, 930.2, and 935

(f) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 183.2, 184, 426.4, 506, 566, 571, 580, 583, 588, 880, 902, and 921

(g) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 565

(h) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 107, 108 and 184

(i) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 163, 174, 182.3, 183.2, 184, 188, 232, 408.1, 426.4, 426.5, 500, 501, 502, 506, 510, 513, 514, 556, 560, 561.1, 561.2, 561.3, 561.5, 561.6, 561.7, 562, 563, 566, 570, 571, 573, 580, 582, 583, 586, 588, 590, 592, 593, 595, 598, 901, 902, 903, 907, 908, 910, 920, 921, 925, 926, and 935

(j) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 163, 165, 183.2, 184, 403, 426.4, 426.5, 500, 501, 502, 506, 510, 511, 514, 556, 560, 561.1, 561.7, 562, 563, 566, 569.2, 570, 571, 573, 580, 582, 583, 586, 588, 590, 592, 593, 595, 598, 901, 902, 903, 907, 908, 910, 921, 923, 924, 926, 930.2, 931 and 935

(k) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 163, 580, 921, 930.2, and 935

(l) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 183.2, 184, 188, 426.1, 426.4, 426.5, 500, 501, 506, 510, 514, 549, 556, 560, 561.1, 561.2, 561.5, 562, 563, 566, 570, 571, 573, 580, 582, 583, 586, 588, 590, 592, 593, 598, 901, 902, 903, 907, 908, 910, 920, 921, 925, 926, 930.2, and 935

(m) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 165, 183.2, 184, 186, 188, 426.4, 426.5, 500, 506, 510, 511, 560, 561.5, 561.6, 561.7, 562, 563, 566, 569.2, 570, 571, 573, 580, 583, 586, 588, 593, 597, 598, 880, 901, 902, 903, 908, 910, 921, 923, 928, 930.2 and 935

(n) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 107 and 108

(o) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 163, 183, 184, 408.1, 426.4, 426.5, 500, 506, 549, 566, 580, 588, 593, 901, 903, 905, 908, 912, 920, 924, 925, 926 and 930.2

(p) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 901, 930.2 and 931

(q) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 163

(r) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 184, 234, 421, 426.4, 426.5, 500, 506, 549, 566, 588, 901, 903, 905, 908, 921, 924, 925, 930.2 and 935

(s) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 163, 184, 426.5, 506, 566, 569.2, 571, 588, 593, 901, 903, 908, 921, 923, 928, 930.2 and 935

(t) Concept: DescriptionOfNonPowerGoodOrService

Costs between Kentucky Utilities Company and Louisville Gas and Electric Company are either charged directly or are allocated by certain assignment methods described below that most accurately distribute the costs.

LG&E and KU Services Company (LKS) and PPL Services Corporation (PPL Services) either directly charge or allocate the costs of service among the affiliated companies using one of several methods that most accurately distributes the costs. The method of cost allocation varies based on the department rendering the service. Any of the methods may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes in the business. Rates are generally determined annually, semi-annually or monthly (based upon actual usage). The assignment methods used by LKS and PPL Services are as follows:

Book Enterprise Value Ratio – This ratio is calculated based on book enterprise value. The ratio is calculated on an annual basis.

Contract Ratio – This ratio is based on the sum of the physical amount (i.e., tons of coal, mmbtu of natural gas) of the contract for coal and natural gas fuel burned for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company and the denominator of which is for all operating companies. This ratio is calculated on an annual basis.

Departmental Charge Ratio – A specific department ratio based upon various factors. The departmental charge ratio typically applies to directly attributable costs such as departmental administrative, support, or material and supply costs, or a combination thereof, that benefit more than one affiliate and that require allocation using general measures of cost causation. Methods for assignment are department-specific depending on the type of service performed and are documented and monitored by the Budget Analysts for each department. The numerator and denominator vary by department. The ratio is based upon various factors such as labor hours, labor dollars, departmental or entity headcount, capital expenditures, operations and maintenance costs, retail energy sales, charitable contributions, generating plant sites, average allocation of direct reports, net book value of utility plant, total line of business assets, electric capital expenditures, substation assets and transformer assets. The Departmental Charge Ratio may only be used with appropriate prior approval and where other applicable ratios would not result in the fair assignment of costs. These ratios are calculated on an annual basis.

Facilities Ratio – This ratio is based on a two-tiered approach with one tier based on the number of employees by department or line of business and the other tier based on the applicable department or line of business ratio. The numerator for the number of employees is the number of employees by department or line of business at the facility and the denominator is the total employees at the facility. This ratio is calculated on an annual basis.

Generation Ratio – This ratio is based on the annual forecast of megawatt hours, the numerator of which is for an operating company and the denominator of which is for all operating companies. This ratio is calculated on an annual basis.

Insurance Policies Ratio – This ratio is based upon a composite percentage of individual insurance policies. This ratio is calculated on an annual basis.

Number of Controls Ratio – This ratio is based on the number of SOX controls for each operating segment, then by the number of SEC registrants within the operating segment. The ratio is calculated on an annual basis.

Number of Customers Ratio – This ratio is based on the number of retail electric and/or gas customers at year-end for the preceding year. This ratio is updated on an annual basis.

Number of Employees Ratio – This ratio is based on the number of employees benefiting from the performance of a service. This ratio is calculated on an annual basis.

Number of Items Processed Ratio – This ratio is based on the number of items processed. This ratio is updated on a monthly basis, based upon actual usage.

Number of Meters Ratio – This ratio is based on number of meters for each affiliate. This ratio is calculated on an annual basis.

Number of Network Users Ratio – This ratio is calculated using two steps. The first step is based upon the number of operational network users at each company at year-end for the preceding year. The second step allocates operational support group network users by number of customers. The result of each step is then added together. This ratio is updated on an annual basis.

Number of Operating Segments Ratio – This ratio is based on the number of applicable operating segments covered by PPL. For services provided by LKS, the operating segments are limited to LG&E and KU. This ratio is calculated on an annual basis.

Number of Plan Participants Ratio – This ratio is based upon the number of participants in the pension plan. This ratio is updated semi-annually.
Ownership Percentages – This ratio is based on the contractual ownership percentages of jointly-owned generating units, information technology, facilities and other capital projects. This ratio is updated as a result of a new jointly-owned capital project and is based on the benefit to the respective company. The numerator is the specific company’s forecasted usage. The denominator is the total forecasted usage of all respective companies.

Plan Assets Ratio – This ratio is based upon the split of plan assets in the pension. This ratio is updated semi-annually.

Rate Base Ratio – This ratio is based upon applicable rate base per entity at year-end for the preceding year. This ratio is updated on an annual basis.

Revenue Ratio – This ratio is based on the sum of the revenue for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company and the denominator of which is for all operating companies. This ratio is calculated on an annual basis.

Square Footage Ratio - This ratio is based on the square footage in a facility occupied by an operating segment. This ratio is updated on a monthly basis.

Statement of Values Ratio – This ratio is based on the insured value of property for each affiliate. This ratio is updated on an annual basis.

Total Assets Ratio – This ratio is based upon the total assets at year-end for the preceding year. This ratio is updated on an annual basis.

Total Spend Ratio – This ratio is based upon total O&M and capital spend per entity at year-end for the preceding year. This ratio is updated on an annual basis.

Total Utility Plant Assets Ratio – This ratio is based on the total utility plant assets at year-end for the preceding year, the numerator of which is for an operating company and the denominator of which is for all operating companies. In the event of joint ownership of a specific asset, ownership percentages are utilized to assign costs. This ratio is calculated on an annual basis.

Transmission Ratio – The Transmission Coordination Agreement (“TCA”) provides “the contractual basis for the coordinated planning, operation, and maintenance of the combined” LG&E and KU transmission system. Pursuant to the terms of the TCA, LG&E/KU “operate their transmission systems as a single control area.” The TCA establishes cost and revenue allocations between LG&E and KU. The Transmission Ratio is based upon Schedule A (Allocation of Operating Expenses of the Transmission System Operator) of the TCA. Transmission System Operator Company allocation percentages are calculated during June of each year to be effective July 1st of each year using the previous year’s summation of the Transmission Peak Demands as found in FERC Form 1 for KU and LG&E, page 400, line 17(b).

Vehicle Cost Allocation Ratio – Based on the costs associated with providing and operating transportation fleet for all affiliated companies including developing fleet policy, administering regulatory compliance programs, managing repair and maintenance of vehicles and procuring vehicles. Such rates are applied based on the specific equipment employment and the measured usage of services by the various company entities. This ratio is calculated monthly based on the actual transportation charges from the previous month. The numerator is the department labor charged to a specific company. The denominator is the total labor costs for the specific department. The ratio is then multiplied by the total transportation costs to determine the amount charged to each company.

(u) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 107, 108, and 184

(v) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounts charged include: 182.3, 183.2, 184, 408.1, 426.5, 500, 502, 505, 506, 510, 512, 546, 549, 551, 552, 553, 554, 560, 566, 580, 588, 597, 598, 901, 903, 908, 920, 922, 925, 926, and 935

(w) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 151, 165, 184, 426.5, 500, 502, 505, 506, 510, 512, 513, 549, 553, 554, 560, 566, 567.1, 580, 586, 588, 880, 901, 903, 921, 923, 931, and 935
(x) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 184, 188, 426.4, 426.5, 500, 506, 512, 554, 563, 566, 570, 571, 580, 583, 593, 597, 598, 818, 874, 887, 902, 921, 930.2, 935
(y) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 184, 426.5, 506, 510, 560, 566, 571, 580, 586, 588, 593, 803, 901, 902, 903, 921, 925 and 935
(z) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 163, 183.2, 184, 186, 426.4, 553, 566, 588, 880, 902, 921, 923 and 935
(aa) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 456.1
(ab) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 184
(ac) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 174, 184, 500, 566, 580, 901, 903, 920, 926 and 935
(ad) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 174, 184, 921, and 931
(ae) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 580, 921 and 935
(af) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 184, 426.5, 580, 588, 593, 903, 921, 925, and 935
(ag) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 184, 902, and 923
(ah) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 107 and 920
(ai) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 107 and 921
(aj) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 232
(ak) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
Accounts charged include: 923
(al) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies
A portion of labor overhead amounts are not included. Due to system configuration and functionality given the volume of transactions, labor overheads are not separately identifiable as services provided by or for affiliate, but are included as a reduction to the amount reported in line 3, Column d.
(am) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies
Most labor overhead amounts are not included. Due to system configuration and functionality given the volume of transactions, labor overheads are not separately identifiable as services provided by or for affiliate, but are included as a reduction to the amount reported in line 10, Column d.