

Rick E. Lovekamp

Sr. Manager Regulatory Strategy/Policy
State Regulation and Rates
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Jeff Cline
Procedure Development Coordinator
Division of General Administration Filings Branch
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601-8294

March 31, 2026

**RE: Kentucky Public Service Commission Annual Financial and Statistical Report,
Kentucky Public Service Commission Annual Report for Major Natural Gas Companies**

Dear Mr. Cline:

On March 19, 2026, pursuant to 807 KAR 5:006, Sec. 4, Louisville Gas and Electric Company ("LG&E") electronically filed with the Commission the 2025 Annual Financial and Statistical Report. LG&E is submitting its FERC Form 1: Annual Report of Major Electric Utilities and the Annual Report for Major Natural Gas Companies via e-mail to PSCED@ky.gov.

Should you require any additional information about these matters, please contact me or Kelly Ann Couch at 502-627-2768.

Sincerely,

A handwritten signature in blue ink, reading 'Rick E. Lovekamp', is positioned above the printed name.

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)

Louisville Gas and Electric Company

Year/Period of Report
End of: 2025/ Q4

FERC FORM NO. 1 (REV. 02-04)

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.	

500 Louisville Gas and Electric Company 01/01/2025 - 12/31/2025

Principal Payment and Interest Information

	Amount	Yes/No
Amount of Principal Payment During Calendar Year	\$300,000,000.00	
Is Principal Current?	Y	
Is Interest Current?	Y	

**LOUISVILLE GAS AND ELECTRIC COMPANY
ADDITIONAL INFORMATION TO BE FURNISHED WITH
2025 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)	<u>INFORMATION NOT AVAILABLE</u>
Number of Farms Served (A farm is any agricultural operating unit consisting of 3 acres or more)	<u>INFORMATION NOT AVAILABLE</u>
Number of KWH sold to all Rural Customers	<u>INFORMATION NOT AVAILABLE</u>
Total Revenue from all Rural Customers	<u>INFORMATION NOT AVAILABLE</u>

LINE DATA

Total number of Miles of Wire Energized (Located in Kentucky)	<u>12,739</u>
Total number of Miles of Pole line (Located in Kentucky)	<u>7,471</u>

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

Bullitt, Hardin, Henry, Jefferson, Meade, Oldham, Shelby, Spencer and Trimble

500 Louisville Gas and Electric Company 01/01/2025 - 12/31/2025

Supplemental Electric Information

	Revenues	KWHs Sold	Customers
Residential (440)	\$542,031,712.00	4,362,948,095	388,146
Commercial and Industrial Sales			
Small (or Comercial)	\$431,524,947.00	3,648,765,020	47,260
Large (or Industrial)	\$178,424,353.00	2,301,734,972	550
Public St and Hwy Lighting (444)	\$1,334,293.00	5,868,229	502
Other Sales to Public Authorities (445)	\$107,471,117.00	1,062,044,851	4,809
Sales to Railroads and Railways (446)			
Interdepartmental Sales (448)			
Total Sales to Ultimate Customers	\$1,260,786,422.00	11,381,361,167	441,267
Sales For Resale (447)	\$54,632,916.00	1,362,320,000	16
Total Sales of Electricity	\$1,315,419,338.00	12,743,681,167	441,283

**LOUISVILLE GAS AND ELECTRIC COMPANY
NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES
SUPPLEMENTAL INFORMATION TO 2025 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)	12/31/2025
2. Total Regular Full-Time Employees	621
3. Total Part-Time and Temporary Employees	7
4. Total Employees	628

Additional Requested Information

Utility Name Louisville Gas and Electric Company

FEIN# (Federal Employer Identification Number)

6	1	-	0	2	6	4	1	5	0
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Contact Person Michael J. Shurer II

Contact Person's E-Mail Address Mshurer@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 Louisville Gas and Electric Company		02 Year/ Period of Report End of: 2025/ 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) 820 West Broadway, Louisville, KY 40202		
05 Name of Contact Person Michael J. Shurer		06 Title of Contact Person Manager, Regulatory Reporting
07 Address of Contact Person (Street, City, State, Zip Code) 645 Hamilton Street, Suite 700, Allentown, PA		
08 Telephone of Contact Person, Including Area Code (610) 774-2772	09 This Report is An Original / A Resubmission (1) ☒ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 03/19/2026

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) 03/19/2026
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.

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)

Louisville Gas and Electric 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, 2025, to and including December 31, 2025

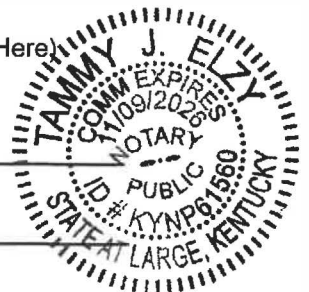
Christopher M. Garrett
 (Signature of Officer)

subscribed and sworn to before me, a Notary Public, in and for
 the State and County named in the above this 19th day of March, 2026

(Apply Seal Here)

My Commission expires November 9, 2026

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



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

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

- 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
- 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.)

<u>Schedules</u>	<u>Pages</u>
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

- 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.

- 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>.
- 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:

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

- 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.
- 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.
- 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.
- 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.
- 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).
- 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.
- For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.
- Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
- 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.
- Schedule specific instructions are found in the applicable taxonomy and on the applicable 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

- 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

FERC FORM NO. 1 (ED. 03-07)

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 Louisville Gas and Electric Company		02 Year/ Period of Report End of: 2025/ 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) 820 West Broadway, Louisville, KY 40202		
05 Name of Contact Person Michael J. Shurer		06 Title of Contact Person Manager, Regulatory Reporting
07 Address of Contact Person (Street, City, State, Zip Code) 645 Hamilton Street, Suite 700, Allentown, PA		
08 Telephone of Contact Person, Including Area Code (610) 774-2772	09 This Report is An Original / A Resubmission (1) ☒ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 03/19/2026
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) 03/19/2026
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: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	None
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	None
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	
22	Materials and Supplies	227	
23	Allowances and Environmental Credits	228	
24	Extraordinary Property Losses	230a	None
25	Unrecovered Plant and Regulatory Study Costs	230b	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	None
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	None
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
49	Transmission of Electricity by ISO/RTOs	331	None
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	None
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	
63.1	Renewable Generating Plant Statistics	404	
64	Hydroelectric Generating Plant Statistics	406	
65	Pumped Storage Generating Plant Statistics	408	None
66	Generating Plant Statistics Pages	410	
66.1	Energy Storage Operations (Large Plants)	414	None
66.2	Energy Storage Operations (Small Plants)	419	None
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		

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ 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 2701 Eastpoint Pkwy, Louisville, KY 40223			
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: 1913-07-02 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 and natural gas services in Metro Louisville and adjacent territory in Kentucky.			
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: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ 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.			
Louisville Gas and Electric Company (LG&E) 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: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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)
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Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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	President	John R. Crockett III			
2	Vice President-Finance and Accounting	Christopher M. Garrett			
3	Vice President-Generation	David L. Tummonds		2025-07-01	
4	Vice President-Customer Service	Shannon L. Montgomery			
5	Vice President and Chief Operating Officer	Thomas A. Jessee			

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

[\(a\)](#) Concept: OfficerTitle

Officers listed include the named executive officers by resolution of the Board of Directors.

Salary information for all officers is on file in the office of the respondent.

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

DIRECTORS

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| 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). |
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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	BOARD OF DIRECTORS AT DECEMBER 31, 2025			
2	John R. Crockett III, President	820 West Broadway, Louisville, KY 40202		
3	Joseph P. Bergstein, Jr., PPL Corporation Executive Vice President and Chief Financial 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 and Chief Legal Officer	645 West Hamilton St. Allentown PA 18101		
6	FORMER DIRECTORS DURING 2025			
7	Angela K. Gosman, PPL Corporation Executive Vice President and Chief Human Resources Officer	645 West Hamilton St. Allentown PA 18101		
8	Francis X. Sullivan, PPL Corporation Executive Vice President and Chief Operating Officer	645 West Hamilton St. Allentown PA 18101		
9	Dean A. Del Vecchio, PPL Corporation Executive Vice President and Chief Technology & Innovation Officer	645 West Hamilton St. Allentown PA 18101		

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ 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	

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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
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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	20250310-5077	03/10/2025	ER25-1542-000	Annual Informational Attachment O Filing of Louisville Gas and Electric Company, et al. Under ER25-1542	Attachment O - Schedule 7, 8, and 10
2	20250310-5077 - Schedule 1	03/10/2025	ER25-1542-000	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

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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)
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Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ 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. ES24-32-000 to issue, from time to time, from May 31, 2024 through June 17, 2026, (a) up to \$750 million in the form of money pool debt, commercial paper or any other type of short-term loan and (b) up to \$750 million in the form of certain long-term debt. The Respondent participates in an intercompany money pool agreement. At December 31, 2025, the Respondent had no borrowings under the money pool. At December 31, 2025, the Respondent had a \$600 million credit facility syndicated with a group of banks that expires in December 2029. This facility was initially authorized by the KPSC at Case No. 2015-00138. The KPSC authorized the most recent extension of the facility at Case No. 2023-00398. At December 31, 2025, the Respondent had no cash borrowings under this facility. At December 31, 2025, the Respondent maintained a commercial paper program for up to \$600 million. Commercial paper issuances are supported by the Respondent's syndicated credit facility based on available capacity. The Respondent had no commercial paper outstanding at December 31, 2025. On August 4, 2025, the Respondent issued \$700 million of 5.85% First Mortgage Bonds due 2055 that settled on August 13, 2025. The issuance was authorized by the KPSC at Case No. 2023-00398. On January 29, 2026, the Respondent amended its \$600 million syndicated credit facility to expire in December 2030. The amendment to this facility is authorized at Case No. 2023-00398. See Note 8 of the Notes to Financial Statements for further discussion of financing activities.			
7. On March 28, 2025, in connection with an office relocation, LG&E changed its principal office address to 820 West Broadway, Louisville, KY 40402.			
8. During the first quarter of 2025, exempt and non-exempt employees received routine wage increases in accordance with annual salary reviews. During the fourth quarter of 2025, the LG&E IBEW employees received wage increases.			
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 31, 2025, David Sinclair resigned as Vice President-Energy Supply and Analysis. Effective April 1, 2025, Charles R. Schram was elected Vice President-Energy Supply and Analysis. Effective April 4, 2025, Francis X. Sullivan resigned as a Director. Effective May 31, 2025, Mary C. Whelan resigned as Vice President-Communications and Corporate Responsibility. Effective July 1, 2025, David L. Tummonds was elected Vice President-Generation. Effective July 1, 2025, Steven B. Turner resigned as Vice President-Generation. Effective September 5, 2025, an updated board of directors was elected comprising of Vincent Sorgi, Joseph P. Bergstein, Jr., Wendy E. Stark and John R. Crockett III.			
14. LG&E is a participant in a cash pooling arrangement, but its proprietary capital ratio is above 30 percent.			

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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	9,395,117,889	8,877,733,985
3	Construction Work in Progress (107)	200	701,160,536	450,392,475
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		10,096,278,425	9,328,126,460
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	3,273,910,792	3,065,963,718
6	Net Utility Plant (Enter Total of line 4 less 5)		6,822,367,633	6,262,162,742
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)		6,822,367,633	6,262,162,742
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)		1,519,174	1,519,174
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		337,223	337,223
19	(Less) Accum. Prov. for Depr. and Amort. (122)		63,360	63,360
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	594,286	594,286
23	Noncurrent Portion of Allowances and Environmental Credits	228		
24	Other Investments (124)			
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		52,531,465	44,491,788
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)		53,399,614	45,359,937
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		33,967,428	7,677,608
36	Special Deposits (132-134)			
37	Working Fund (135)		20,000	180,000
38	Temporary Cash Investments (136)		128,184,096	
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		155,229,110	135,872,407
41	Other Accounts Receivable (143)		27,021,281	22,056,328
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,472,463	4,005,943
43	Notes Receivable from Associated Companies (145)		35,521,438	40,181
44	Accounts Receivable from Assoc. Companies (146)		46,288,720	40,004,380
45	Fuel Stock (151)	227	58,414,190	64,356,398
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	67,969,700	62,447,577
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		

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)
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances and Environmental Credits (158.1, 158.2, 158.3, and 158.4)	228	129	130
53	(Less) Noncurrent Portion of Allowances and Environmental Credits	228		
54	Stores Expense Undistributed (163)	227	710,862	1,121,787
55	Gas Stored Underground - Current (164.1)		33,272,694	29,321,830
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		10,304,677	9,746,215
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)		19,374	59,930
60	Rents Receivable (172)		2,830,060	3,798,684
61	Accrued Utility Revenues (173)		97,310,268	87,526,223
62	Miscellaneous Current and Accrued Assets (174)		1,572,100	835,465
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)		693,163,664	461,039,200
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		20,041,076	14,212,438
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	84,592,466	83,137,184
72	Other Regulatory Assets (182.3)	232	421,945,508	412,171,805
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,444,018	5,654,871
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	17,082,019	10,001,058
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		8,166,501	9,229,847
82	Accumulated Deferred Income Taxes (190)	234	173,479,747	176,815,964
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		726,751,335	711,223,167
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		8,297,201,420	7,481,304,220
Page 110-111				

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: StoresExpenseUndistributed		
Balance at Beginning of Year	\$	1,121,787
Total Debits		3,313,239
Total Credits		(3,724,164)
Balance at End of Year	\$	710,862
(b) Concept: AccumulatedDeferredIncomeTaxes		
Balance at Beginning of Year	\$	176,815,964
Less Debits to:		
Account 410.1		15,418,167
Account 410.2		2,203
Other Balance Sheet Accounts		4,009,974
Plus Credits to:		
Account 411.1		15,814,939
Account 411.2		279,188
Balance at End of Year	\$	173,479,747
(c) Concept: StoresExpenseUndistributed		
Balance at Beginning of Year	\$	167,076
Total Debits		3,148,764
Total Credits		(2,194,053)
Balance at End of Year	\$	1,121,787
(d) Concept: AccumulatedDeferredIncomeTaxes		
Balance at Beginning of Year	\$	184,635,787
Less Debits to:		
Account 410.1		14,369,418
Account 410.2		66
Other Balance Sheet Accounts		6,035,855
Plus Credits to:		
Account 411.1		12,583,876
Account 411.2		1,640
Balance at End of Year	\$	176,815,964

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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	425,170,424	425,170,424
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	1,014,081,499	788,081,499
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	835,889	835,889
11	Retained Earnings (215, 215.1, 216)	118	1,777,877,524	1,669,268,425
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)		3,216,293,558	2,881,684,459
17	LONG-TERM DEBT			
18	Bonds (221)	256	2,889,200,000	2,489,200,000
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)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,972,504	4,058,348
24	Total Long-Term Debt (lines 18 through 23)		2,885,227,496	2,485,141,652
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		12,157,770	9,500,652
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		907,640	1,917,290
29	Accumulated Provision for Pensions and Benefits (228.3)		46,234,617	44,928,291
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities		4,128,253	3,397,503
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		76,768,444	88,318,463
35	Total Other Noncurrent Liabilities (lines 26 through 34)		140,196,724	148,062,199
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)			24,960,667
38	Accounts Payable (232)		274,847,085	171,018,064
39	Notes Payable to Associated Companies (233)		1,868	43,360,972
40	Accounts Payable to Associated Companies (234)		73,440,952	64,388,295
41	Customer Deposits (235)		36,637,242	35,548,418
42	Taxes Accrued (236)	262	60,493,583	39,581,673
43	Interest Accrued (237)		33,809,948	20,738,773
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		2,607,436	2,266,011
48	Miscellaneous Current and Accrued Liabilities (242)		24,942,937	24,650,665
49	Obligations Under Capital Leases-Current (243)		5,322,959	5,843,204

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)
50	Derivative Instrument Liabilities (244)		4,739,682	3,835,930
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		4,128,253	3,397,503
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)		512,715,439	432,795,169
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		11,218,487	8,854,723
57	Accumulated Deferred Investment Tax Credits (255)	266	29,208,187	29,721,459
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	13,810,927	2,822,688
60	Other Regulatory Liabilities (254)	278	495,959,088	512,555,543
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		867,522,795	858,872,549
64	Accum. Deferred Income Taxes-Other (283)		125,048,719	120,793,779
65	Total Deferred Credits (lines 56 through 64)		1,542,768,203	1,533,620,741
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		8,297,201,420	7,481,304,220
Page 112-113				

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 Utility 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)
17	Provision for Deferred Income Taxes (410.1)	234, 272	130,917,345	139,493,259			100,280,261	102,543,539	30,637,084	36,949,720		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	138,162,220	132,182,392			110,975,698	107,378,509	27,186,522	24,803,883		
19	Investment Tax Credit Adj. - Net (411.4)	266	(513,272)	(790,992)			(513,272)	(790,991)		(1)		
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)		17	35			17	35				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)											
24.1	(Less) Gains from Disposition of Environmental Credits (411.11)		357,525				357,525					
24.2	Losses from Disposition of Environmental Credits (411.12)											
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24.2)		1,344,977,118	1,244,798,366			1,025,727,754	979,841,060	319,249,364	264,957,306		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		406,298,618	392,052,613			310,481,678	298,307,507	95,816,940	93,745,106		
28	Other Income and Deductions											
29	Other Income											
30	Nonutility Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,707,040	2,810,510								
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,521,441	2,311,289								
33	Revenues From Nonutility Operations (417)		1,416,576	1,235,046								
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)		5,579,515	2,612,236								
38	Allowance for Other Funds Used During Construction (419.1)		13,525,202	6,515,647								

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 Utility 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)
66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)											
67	Interest on Debt to Assoc. Companies (430)		173,176	336,554								
68	Other Interest Expense (431)		4,467,300	2,171,935								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		7,609,857	3,323,116								
70	Net Interest Charges (Total of lines 62 thru 69)		114,062,892	103,401,988								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		309,209,099	297,195,694								
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										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		309,209,099	297,195,694								
Page 114-117												

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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		1,669,268,425	1,559,572,731
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1	Adjustments to Retained Earning 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)		309,209,099	297,195,694
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		(200,600,000)	(187,500,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(200,600,000)	(187,500,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,777,877,524	1,669,268,425
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)		1,777,877,524	1,669,268,425
	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 undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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)	309,209,099	297,195,694
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	294,917,787	284,522,665
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Plant and Regulatory Debits and Credits	31,696,812	32,390,117
5.2	Amortization of Debt Discount and Debt Issuance Costs	2,918,081	3,023,028
5.3	Amortization of Research and Development Projects		17,333
5.4	Provision for Pension and Postretirement Benefits	(312,190)	(1,545,789)
5.5	(Gain)/Loss on Sales of Assets	418,324	1,448
5.6	Other Deductions		
5.7	Other		
8	Deferred Income Taxes (Net)	(7,521,860)	7,309,293
9	Investment Tax Credit Adjustment (Net)	(513,272)	(790,992)
10	Net (Increase) Decrease in Receivables	(26,817,985)	(37,126,742)
11	Net (Increase) Decrease in Inventory	(2,499,684)	(13,501,583)
12	Net (Increase) Decrease in Allowances and Environmental Credits Inventory	1	2
13	Net Increase (Decrease) in Payables and Accrued Expenses	45,813,511	21,577,668
14	Net (Increase) Decrease in Other Regulatory Assets	(32,674,334)	(14,634,203)
15	Net Increase (Decrease) in Other Regulatory Liabilities	5,965,073	666,228
16	(Less) Allowance for Other Funds Used During Construction	13,525,202	6,515,647
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Net (Increase) Decrease in Prepayments and Other Assets	(558,462)	2,434,403
18.2	Net Increase (Decrease) in Customer Advances for Construction	2,363,764	2,319,461
18.3	Pension and Postretirement Funding	884,925	196,146
18.4	Net Increase (Decrease) in Other Liabilities	(665,823)	(1,184,292)
18.5	Net Increase (Decrease) in ARO Liabilities		
18.6	Net (Increase) Decrease in Special Funds	(3)	779,629
18.7	Other	3	(2)
18.8	Net (Increase) Decrease in Other Deferred Debits	(150,300)	(4,619,316)
18.9	Net Increase (Decrease) in Other Deferred Credits	10,988,239	1,093,116
18.10	Payments for Asset Retirement Obligations	(9,720,946)	(11,214,196)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	610,215,558	562,393,469
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(649,671,988)	(376,821,351)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant	(126,455,068)	(62,315,525)
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	(13,525,202)	(6,515,647)
31	Other (provide details in footnote):		
31.1	Costs of Removal of Utility Plant	(16,244,311)	(18,329,158)

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)
31.2	Proceeds from the settlements of insurance claims		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(778,846,165)	(450,950,387)
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	(35,481,256)	(40,181)
40	Contributions and Advances from Assoc. and Subsidiary Companies	(43,359,105)	43,357,322
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 and Environmental Credits Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Other	2	
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(857,686,524)	(407,633,246)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	699,797,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	LG&E and KU Energy LLC Equity Contribution	281,000,000	65,000,000
64.2	Issuance of Commercial Paper		
66	Net Increase in Short-Term Debt (c)		24,960,667
67	Other (provide details in footnote):		
67.1	Net Change in Restricted Cash	9,187,439	9,154,836
70	Cash Provided by Outside Sources (Total 61 thru 69)	989,984,439	99,115,503
72	Payments for Retirement of:		
73	Long-term Debt (b)	(300,000,000)	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Debt Issuance Costs	(7,638,890)	(508,372)
76.2	Net Change in Restricted Cash		
76.3	Acquisition of outstanding long-term debt		
76.4	Return of Capital to Parent	(55,000,000)	(76,000,000)
78	Net Decrease in Short-Term Debt (c)	(24,960,667)	
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(200,600,000)	(187,500,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	401,784,882	(164,892,869)
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)	154,313,916	(10,132,646)
88	Cash and Cash Equivalents at Beginning of Period	\$7,857,608	17,990,254
90	Cash and Cash Equivalents at End of Period	\$162,171,524	\$7,857,608

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Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: CashAndCashEquivalents			
Cash and cash equivalents are comprised of the following amounts:			
Cash (131)	\$		7,677,608
Working Fund (135)			180,000
Total Cash and Cash Equivalents	\$		7,857,608
(b) Concept: CashAndCashEquivalents			
Cash and cash equivalents are comprised of the following amounts:			
Cash (131)	\$		33,967,428
Working Fund (135)			20,000
Temporary Cash Investments (136)			128,184,096
Total Cash and Cash Equivalents	\$		162,171,524
(c) Concept: CashAndCashEquivalents			
Cash and cash equivalents are comprised of the following amounts:			
Cash (131)	\$		7,677,608
Working Fund (135)			180,000
Total Cash and Cash Equivalents	\$		7,857,608

[illegible]

As permitted by the FERC for the 2025 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, 2025 up to February 20, 2026, the date that LGE's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposed through March 19, 2026. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

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 Registrant's related activities and disclosures. Within combined disclosures, amounts are disclosed for any Registrant when significant.

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, Income Statement and Statement of Cash Flows	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 Intangibles.
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 Long-Term Assets
Payable and Accrued expenses	Reported in Accounts Payable (232), Customer Deposits (235), 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	Reported in Miscellaneous Deferred Debits (186)	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 Financing Activity on Statement of Cash Flows	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 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) on the Balance Sheet and Depreciation (403) on the Income Statement.	Reported in Regulatory Assets - Noncurrent - Other on the Balance Sheet and Operations and Maintenance Expense on the Income Statement.
Accounts receivable	Customer Accounts Receivable reported in (142) and Other Accounts Receivable reported in (143)	Reported in Total Accounts Receivable
Coal purchases and in-transit coal	Reported in Fuel Stock (151)	Reported in Material and Supplies
Long-term debt due within one year	Reported in Bonds (221)	Reported in Current Liabilities
Fuel Expenses	Reported in Operation Expenses	Reported in Fuel Expenses
Energy Purchases	Reported in Operation Expenses	Reported in Energy Purchases
Energy Purchases from Affiliates	Reported in Operation Expenses	Reported in Energy Purchases from Affiliates
Operation and maintenance expenses	Reported separately in Operation Expenses and in Maintenance Expenses	Reported in Other Operation & Maintenance
Land rights, franchises and consents	Reported in Utility Plant (101)	Reported in Other Intangibles
UTP Interest - Federal Income Tax	Reported in Other Interest Expense (431)	Reported in Provision for Income Tax
Prepaid Pension	Reported in Special Funds (128)	Reported in Other Noncurrent Assets
Interest Expense	Reported as Interest on Long-Term Debt	Reported as Interest Expense
KY Electric Retired Reg Asset Recovery	Reported in Unrecovered Plant and Regulatory Study Costs (182.2)	Reported in Regulatory Assets
Post-employment and post-retirement benefits payable	Reported in Accumulated Provision for Pensions and Benefits (228.3)	Reported in Other Noncurrent Liabilities
Natural gas pipeline inspection retesting costs incurred related to new federal regulations.	Reported in PP&E (101,107). Reported as Investing Activity on Statement of Cash Flows	Reported in Noncurrent Regulatory Assets. Reported as Operating Activity on Statement of Cash Flows.
Gas stored underground	Reported in Gas Stored Underground (164.1)	Reported in Material and Supplies
Intangible Assets related to Land Sale	Reported in Gross Additions to Common Utility Plant (108.9)	Reported as Other Intangibles. Reported as Operating Activities on Statement of Cash Flows

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.

(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. The if-converted method, which assumes the securities were converted to common stock at the start of the period (or issuance), is used to determine the dilutive effects of convertible 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
<u>PPL</u>				
2025	\$ 154	\$ 84	\$ 98	\$ 140 (b)
2024	130	109	85	154 (b)
2023	95	87	52	130 (b)
<u>PPL Electric</u>				
2025	\$ 41	\$ 33	\$ 35	\$ 39 (c)
2024	50	56	65	41 (c)
2023	33	52	35	50 (c)
<u>LG&E</u>				
2025	\$ 3	\$ 4	\$ 2	\$ 5
2024	6	4	7	3
2023	4	4	2	6
<u>KU</u>				
2025	\$ 2	\$ 5	\$ 3	\$ 4
2024	2	4	4	2
2023	3	3	4	2

(a) Primarily related to uncollectible accounts written off.
(b) Includes \$43 million, \$39 million and \$41 million related to other accounts receivable at December 31, 2025, 2024 and 2023.
(c) Includes \$2 million, \$2 million and \$3 million related to other accounts receivable at December 31, 2025, 2024 and 2023.

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 non-financial 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:

	2025	2024	2023
PPL	\$ 32	\$ 20	\$ 12
PPL Electric	13	9	7
LG&E	6	3	1
KU	8	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:

	2025		2024		2023	
PPL	3.06	%	3.20	%	3.26	%
PPL Electric	2.46	%	2.52	%	2.62	%
LG&E	3.69	%	4.02	%	4.00	%
KU	3.68	%	3.86	%	3.95	%

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 reporting 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.

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, 2025, 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 PPL Electric, LG&E, KU and RIE, 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 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, 2025, 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 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 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 payables were recorded:

	2025	2024
PPL Electric	\$ (27)	\$ (2)
LG&E	(7)	(2)
KU	(10)	(5)

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 gas supply clause.

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

	2025			
	PPL	PPL Electric	LG&E	KU
Fuel	\$ 157	\$ —	\$ 58	\$ 99
Natural gas stored underground	50	—	33	—
Materials and supplies	344	151	69	84
Total	\$ 551	\$ 151	\$ 160	\$ 183

	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

(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 Income Tax Disclosures

Effective December 31, 2025, the Registrants retrospectively adopted accounting guidance to improve income tax disclosures. The guidance requires enhanced disclosures about disaggregated rate reconciliation in eight specific categories, presented in both percentages and currency amounts. Further disaggregation by jurisdiction or nature of the item, or both, is required if over a 5% threshold. The utility industry has specific tax rate impacts due to federal and state rate-making requirements, which frequently exceed the 5% threshold. Accordingly, a ninth category is used to disaggregate the utility rate-making tax adjustments. The guidance also requires disclosure of the amount of income taxes paid disaggregated by federal, state, and foreign. See Note 6 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 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.

"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 RIE. "Corporate and Other" is presented to reconcile segment information to PPL's consolidated results and is not a reportable segment.

PPL's Chief Operating Decision Maker (CODM) is the CLC. 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 a reconciliation of segment net income to consolidated net income for the year ended December 31, 2025:

	Kentucky Regulated	Pennsylvania Regulated	Rhode Island Regulated	Total
Operating Revenues from external customers (a)	\$ 3,760	\$ 3,113	\$ 2,168	\$ 9,041
<i>Reconciliation of revenue</i>				
Corporate and other revenues				1
Total consolidated revenues				\$ 9,042
<i>Less:</i>				
Fuel	855	—	—	855
Energy Purchases	214	876	802	1,892
Operation and maintenance	818	630	851	2,299
Depreciation	717	413	177	1,307
Taxes, other than income	102	151	170	423
Other (income) expense - net	(53)	(48)	(33)	(134)
Interest (income) from affiliate	—	(9)	(3)	(12)
Interest expense	264	257	111	632
Income taxes	169	204	8	381
Segment net income	\$ 674	\$ 639	\$ 85	\$ 1,398
<i>Reconciliation of segment profit or loss to consolidated net income</i>				
Corporate and other net loss				(217)
Net Income				\$ 1,181

(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, 2025 are as follows:

	Kentucky Regulated	Pennsylvania Regulated	Rhode Island Regulated	Total Segments	Corporate and Other	Consolidated Total
<i>Other Segment Disclosures</i>						
Amortization (a)	\$ 43	\$ 48	\$ 1	\$ 92	\$ 12	\$ 104
Deferred income taxes and investment tax credits (b)	(9)	24	28	43	149	192
Expenditures for long lived assets	1,752	1,620	668	4,040	2	4,042

(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 a reconciliation of segment net income 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
<i>Reconciliation of revenue</i>				
Corporate and other revenues				—
Total consolidated revenues				\$ 8,462
<i>Less:</i>				
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)	(45)	(20)	(94)
Interest (income) from affiliate	—	(33)	(4)	(37)
Interest expense	240	246	95	581
Income taxes	160	176	22	358
Segment net income	\$ 620	\$ 574	\$ 109	\$ 1,303
<i>Reconciliation of segment profit or loss to consolidated net income</i>				
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
<i>Other Segment Disclosures</i>						
Amortization (a)	\$ 24	\$ 45	\$ 1	\$ 70	\$ 8	\$ 78
Deferred income taxes and investment tax credits (b)	2	129	38	169	27	196
Expenditures for long lived assets	1,088	1,229	495	2,812	(7)	2,805

(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 a reconciliation of segment net income 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
<i>Reconciliation of revenue</i>				
Corporate and other revenues				1
Total consolidated revenues				\$ 8,312
<i>Less:</i>				
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
<i>Reconciliation of segment profit or loss to consolidated net income</i>				
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
<i>Other Segment Disclosures</i>						
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 following provides Balance Sheet data for the segments and reconciliation to PPL's consolidated results as of:

	As of December 31,	
	2025	2024
Total Assets		
Kentucky Regulated	\$ 19,060	\$ 17,626
Pennsylvania Regulated	16,886	15,475
Rhode Island Regulated	7,510	7,055
Corporate and Other (a)	1,788	913
Total	\$ 45,244	\$ 41,069

(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 and include unbilled amounts, which represent the amounts due from customers as a result of customer's bills being rendered throughout the month, rather than at the end of the month. 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 being rendered throughout the month, rather than 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 being rendered throughout the month,

rather than 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:

	2025			
	PPL	PPL Electric	LG&E	KU
Operating Revenues (a)(b)	\$ 9,042	\$ 3,113	\$ 1,748	\$ 2,064
Revenues derived from:				
Alternative revenue programs (c)	153	21	(2)	—
Other (d)	(25)	(17)	(4)	(4)
Revenues from Contracts with Customers	\$ 9,170	\$ 3,117	\$ 1,742	\$ 2,060

	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

- (a) PPL includes \$2,168 million, \$2,024 million and \$1,851 million for the twelve months ended December 31, 2025, 2024, and 2023 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, 2023, \$146 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 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								
2025								
PA Regulated	\$ 1,656	\$ 448	\$ 56	\$ 54	\$ —	\$ —	\$ 903	\$ 3,117
RI Regulated (c)	1,249	671	83	86	—	—	213	2,302
KY Regulated	1,616	1,063	627	309	25	111	—	3,751
Total PPL	\$ 4,521	\$ 2,182	\$ 766	\$ 449	\$ 25	\$ 111	\$ 1,116	\$ 9,170
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
PPL Electric								
2025	\$ 1,656	\$ 448	\$ 56	\$ 54	\$ —	\$ —	\$ 903	\$ 3,117
2024	\$ 1,502	\$ 418	\$ 47	\$ 57	\$ —	\$ —	\$ 818	\$ 2,842
2023	\$ 1,649	\$ 444	\$ 55	\$ 54	\$ —	\$ —	\$ 796	\$ 2,998
LG&E								
2025	\$ 809	\$ 540	\$ 187	\$ 139	\$ —	\$ 67	\$ —	\$ 1,742
2024	\$ 754	\$ 518	\$ 188	\$ 147	\$ —	\$ 50	\$ —	\$ 1,657
2023	\$ 751	\$ 517	\$ 189	\$ 104	\$ —	\$ 47	\$ —	\$ 1,608
KU								
2025	\$ 807	\$ 523	\$ 440	\$ 169	\$ 25	\$ 96	\$ —	\$ 2,060
2024	\$ 756	\$ 510	\$ 447	\$ 176	\$ 23	\$ 64	\$ —	\$ 1,976
2023	\$ 707	\$ 484	\$ 448	\$ 168	\$ 22	\$ 46	\$ —	\$ 1,875

- (a) Primarily includes revenues from pole attachments, street lighting, other public authorities and other non-core businesses. For the years ended December 31, 2023, 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 2025 revenues would result in \$534 million of Residential, \$409 million of Commercial and \$83 million of Industrial for the Rhode Island Regulated segment being presented as "Other" for the year ended December 31, 2025. 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:

	2025	2024	2023
PPL (a)	\$ 101	\$ 103	\$ 79
PPL Electric (a)	32	52	47
LG&E	4	4	4
KU	5	4	2

- (a) 2024 and 2023 includes amounts impaired related to PPL Electric's billing issues. See Note 7 in PPL's 2024 Form 10-K for additional information.

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. The Registrants' contract liabilities are not material at December 31, 2025, 2024 and 2023.

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 2025, 2024 or 2023.

(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 2025, 2024 or 2023.

(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 2025, 2024 or 2023.

(KU)

KU is authorized to issue up to 5,300,000 shares of preferred stock and 2,000,000 shares of preference stock. KU had no preferred or preference stock issued or outstanding in 2025, 2024 or 2023.

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. The If-Converted Method is applied to the Exchangeable Senior Notes due 2028 and 2030 (Exchangeable Notes) issued in February 2023 and November 2025.

Incremental non-participating securities that have a dilutive impact are detailed in the table below. In 2025, these securities include forward sales of PPL common stock issued through an ATM Program and the number of shares needed to settle the conversion premium on the Exchangeable Notes. The forward sale agreements are dilutive under the Treasury Stock Method to the extent the average stock price of PPL's common shares exceeds the forward sale price prescribed in the agreements. See Note 8 for additional information on the ATM Program and the Exchangeable Senior Notes due 2030 and Note 8 in PPL's Annual Report on Form 10-K for the year ended December 31, 2023 for additional information on the Exchangeable Notes due 2028.

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:

	2025	2024	2023
Income (Numerator)			
Net income	\$ 1,181	\$ 888	\$ 740
Less amounts allocated to participating securities	2	2	1
Net income available to PPL common shareowners - Basic and Diluted	<u>\$ 1,179</u>	<u>\$ 886</u>	<u>\$ 739</u>
Shares of Common Stock (Denominator)			
Weighted-average shares - Basic EPS	739,406	737,756	737,036
Add incremental non-participating securities:			
Dilutive share-based payment awards (a)	2,724	2,097	1,130
Forward sale agreements	170	—	—
Exchangeable Notes	1,048	—	—
Weighted-average shares - Diluted EPS	<u>743,348</u>	<u>739,853</u>	<u>738,166</u>
Basic EPS			
Net Income available to PPL common shareowners	<u>\$ 1.60</u>	<u>\$ 1.20</u>	<u>\$ 1.00</u>
Diluted EPS			
Net Income available to PPL common shareowners	<u>\$ 1.59</u>	<u>\$ 1.20</u>	<u>\$ 1.00</u>

(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 the DRIP as follows (in thousands):

	2025	2024	2023
DRIP	762	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:			
	<u>2025</u>	<u>2024</u>	<u>2023</u>
Stock-based compensation awards	106	—	243
Forward sale agreements	10,040	—	—

6. Income and Other Taxes

(PPL)

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:

	2025	2024
Deferred Tax Assets		
Deferred investment tax credits	\$ 27	\$ 28
Regulatory liabilities	186	133
Income taxes due to customers	397	418
Accrued pension and postretirement costs	99	112
State loss carryforwards	181	224
Federal and state tax credit carryforwards	35	24
Internal Revenue Code Section 197 intangibles	67	72
Contributions in aid of construction	206	163
Bad debt	34	37
Other	130	114
Valuation allowances	(184)	(224)
Total deferred tax assets	<u>1,178</u>	<u>1,101</u>
Deferred Tax Liabilities		
Plant - net	4,105	3,898
Regulatory assets	432	432
Prepayments	49	39
Goodwill	52	38
Other	37	38
Total deferred tax liabilities	<u>4,675</u>	<u>4,445</u>
Net deferred tax liability	<u>\$ 3,497</u>	<u>\$ 3,344</u>

State deferred taxes are determined by entity and by jurisdiction. As a result, \$9 million and \$12 million of net deferred tax assets are shown as "Other noncurrent assets" on the Balance Sheets for 2025 and 2024.

At December 31, 2025, 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	\$ 4,281	\$ 181	\$ (181)	2026-2045
State charitable contributions	1	—	—	2026-2030
Foreign capital loss	8	2	(2)	Indefinite

	Gross	Deferred Tax Asset	Valuation Allowance	Expiration
Credit carryforwards				
Federal investment tax credit		\$ 26	\$ —	2045
Federal - other		2	—	2045
State recycling credit		6	—	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:

	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions	Balance at End of Period
2025	\$ 224	\$ 4	\$ —	\$ 44 (a)	\$ 184
2024	245	3	1	25 (b)	224
2023	213	54 (c)	—	22 (d)	245

(a) In 2025, PPL recorded a \$41 million decrease in a valuation allowance on a 2005 state net operating loss carryforward that expired in 2025.

(b) In 2024, PPL recorded a \$23 million decrease in a valuation allowance on a 2004 state net operating loss carryforward that expired in 2024.

(c) 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.

(d) In 2023, PPL recorded a \$22 million decrease in a valuation allowance on a 2003 state net operating loss carryforward that expired in 2023.

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, income tax cash payments and refunds by federal and state jurisdictions, and details of "Taxes, other than income" were as follows:

	2025	2024	2023
Income Tax Expense (Benefit)			
Current - Federal (a)	\$ 46	\$ 23	\$ (175)
Current - State	53	9	37
Total Current Expense (Benefit)	99	32	(138)
Deferred - Federal (a)	172	137	286
Deferred - State	27	64	48
Total Deferred Expense (Benefit), excluding operating loss carryforwards	199	201	334
Amortization of investment tax credit	(3)	(3)	(3)
Tax expense (benefit) of operating loss carryforwards			
Deferred - Federal	1	1	3
Deferred - State	(5)	(3)	(12)
Total Tax Expense (Benefit) of Operating Loss Carryforwards	(4)	(2)	(9)
Total income tax expense (benefit)	\$ 291	\$ 228	\$ 184
Total income tax expense (benefit) - Federal	\$ 216	\$ 158	\$ 111
Total income tax expense (benefit) - State	75	70	73
Total income tax expense (benefit)	\$ 291	\$ 228	\$ 184

(a) In 2025, 2024, and 2023, PPL purchased approximately \$153 million, \$27 million and \$300 million of renewable tax credits and recorded a current tax benefit and a deferred tax expense for utilization of approximately \$138 million, \$61 million and \$250 million of the credits, respectively.

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

	2025	2024	2023
Other comprehensive income	\$ (6)	\$ (8)	\$ (14)
Valuation allowance recorded to other comprehensive income	—	—	(1)
Total	\$ (6)	\$ (8)	\$ (15)

	2025	2024	2023
Reconciliation of Income Tax Expense (Benefit)			
Federal income tax on Income Before Income Taxes at statutory tax rate	\$ 309	\$ 234	\$ 194
Increase (decrease) due to:			
State income taxes, net of federal income tax benefit (a)	75	67	69
Tax credits (federal):			
Investment tax credits	(17)	(5)	(19)
Other tax credits	(1)	(5)	(7)
Subtotal	(18)	(10)	(26)
Utility rate-making tax adjustments (federal and state):			
Amortization of excess deferred taxes	(51)	(46)	(48)
AFUDC Equity	(20)	(10)	(6)
Flow-through rate-making (b)	(10)	(11)	(4)
Subtotal	(81)	(67)	(58)
Other	6	4	5
Total increase (decrease)	(18)	(6)	(10)
Total income tax expense	\$ 291	\$ 228	\$ 184

(a) Jurisdictions that make up the majority of state income taxes, net of federal effect, are Kentucky and Pennsylvania.

(b) Flow-through occurs when the regulator excludes deferred tax expense or benefit from recoverable costs when determining income tax expense.

Income tax cash payments (refunds) by federal and state jurisdictions:

	2025	2024	2023
Federal	\$ 66 (a)	\$ (149) (b)	\$ 252 (c)
Pennsylvania	20	21	24
Kentucky	6	4	4
Other states	1	1	1
Total	\$ 93	\$ (123)	\$ 281

(a) Includes purchase price of transferable tax credits of \$40 million.

(b) Includes refund for the carry-back of acquired transferable tax credits applied to the 2021 tax return of \$200 million and purchase price of transferable tax credits of \$20 million.

(c) Includes refund of \$55 million and purchase price of transferable tax credits of \$282 million.

	2025	2024	2023
Taxes, other than income			
State gross earnings and state gross receipts	\$ 214	\$ 167	\$ 195
Property and other	209	207	197
Total	\$ 423	\$ 374	\$ 392

(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:

	2025	2024
Deferred Tax Assets		
Accrued pension and postretirement costs	\$ 29	\$ 36
Contributions in aid of construction	156	120
Regulatory liabilities	57	40
Income taxes due to customers	177	184
Other	25	22
Total deferred tax assets	444	402
Deferred Tax Liabilities		
Electric utility plant - net	2,028	1,934
Regulatory assets	165	160
Prepayments	30	30
Other	2	4
Total deferred tax liabilities	2,225	2,128
Net deferred tax liability	\$ 1,781	\$ 1,726

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, income tax cash payments and refunds by federal and state jurisdictions, and details of "Taxes, other than income" were as follows:

	2025	2024	2023
Income Tax Expense			
Current - Federal	\$ 136	\$ 44	\$ 91
Current - State	44	4	31
Total Current Expense	180	48	122
Deferred - Federal	17	86	28
Deferred - State	7	42	18
Total Deferred Expense, excluding operating loss carryforwards	24	128	46
Total income tax expense	\$ 204	\$ 176	\$ 168
Total income tax expense - Federal	\$ 153	\$ 130	\$ 119
Total income tax expense - State	51	46	49
Total income tax expense	\$ 204	\$ 176	\$ 168

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
Reconciliation of Income Tax Expense (Benefit)						
Taxes at statutory tax rate	\$ 177	21.0 %	\$ 158	21.0 %	\$ 144	21.0 %
Increase (decrease) due to:						
State income taxes, net of federal income tax benefit (a)	52	6.1 %	47	6.2 %	48	7.1 %
Utility rate-making tax adjustments (federal and state):						
Amortization of excess deferred federal income taxes	(10)	(1.2) %	(10)	(1.3) %	(11)	(1.6) %
AFUDC Equity	(8)	(1.0) %	(6)	(0.7) %	(4)	(0.7) %
Flow-through rate-making (b)	(10)	(1.2) %	(11)	(1.5) %	(4)	(0.7) %
Subtotal	(28)	(3.4) %	(27)	(3.5) %	(19)	(3.0) %
Other	3	0.5 %	(2)	(0.2) %	(5)	(0.6) %
Total increase (decrease)	27	3.2 %	18	2.5 %	24	3.5 %
Total income tax expense	\$ 204	24.2 %	\$ 176	23.5 %	\$ 168	24.5 %

- (a) The jurisdiction that makes up the majority of state income taxes, net of federal effect, is Pennsylvania.
- (b) Flow-through occurs when the regulator excludes deferred tax expense or benefit from recoverable costs when determining income tax expense.

Income tax cash payments by federal and state jurisdictions:

	2025	2024	2023
Federal	\$ 109	\$ 62	\$ 68
Pennsylvania	20	21	24
Total	\$ 129	\$ 83	\$ 92

	2025	2024	2023
Taxes, other than income			
State gross receipts	\$ 144	\$ 122	\$ 136
Property and other	7	9	7
Total	\$ 151	\$ 131	\$ 143

(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:

	2025	2024
Deferred Tax Assets		
Contributions in aid of construction	\$ 17	\$ 18
Regulatory liabilities	18	18
Accrued pension and postretirement costs	—	4
Deferred investment tax credits	7	7
Income taxes due to customers	104	110
State tax credit carryforwards	5	6
Lease liabilities	4	4
Other	9	6
Valuation allowances	(5)	(6)
Total deferred tax assets	159	167
Deferred Tax Liabilities		
Plant - net	884	875
Regulatory assets	87	88
Lease right-of-use assets	4	4
Other	3	3
Total deferred tax liabilities	978	970
Net deferred tax liability	\$ 819	\$ 803

At December 31, 2025, LG&E had \$5 million of state credit carryforwards that expire in 2028 and a \$5 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, income tax cash payments and refunds by federal and state jurisdictions, and details of "Taxes, other than income" were:

	2025	2024	2023
Income Tax Expense (Benefit)			
Current - Federal	\$ 72	\$ 60	\$ 70
Current - State	14	11	13
Total Current Expense (Benefit)	86	71	83
Deferred - Federal	(10)	1	(15)
Deferred - State	3	6	2
Total Deferred Expense (Benefit)	(7)	7	(13)
Amortization of investment tax credit - Federal	(1)	(1)	(1)
Total income tax expense (benefit)	\$ 78	\$ 77	\$ 69
Total income tax expense (benefit) - Federal	\$ 61	\$ 60	\$ 54
Total income tax expense (benefit) - State	17	17	15
Total income tax expense (benefit)	\$ 78	\$ 77	\$ 69

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
Reconciliation of Income Tax Expense (Benefit)						
Taxes at statutory tax rate	\$ 81	21.0 %	\$ 79	21.0 %	\$ 70	21.0 %
Increase (decrease) due to:						
State income taxes, net of federal income tax benefit (a)	15	3.8 %	14	3.7 %	13	3.8 %
Utility rate-making tax adjustments (federal and state):						
Amortization of excess deferred taxes	(14)	(3.5) %	(13)	(3.4) %	(13)	(3.9) %
AFUDC Equity	(4)	(1.1) %	(2)	(0.4) %	(1)	(0.3) %
Subtotal	(18)	(4.6) %	(15)	(3.8) %	(14)	(4.2) %
Other	—	— %	(1)	(0.3) %	—	— %
Total increase (decrease)	(3)	(0.8) %	(2)	(0.4) %	(1)	(0.4) %
Total income tax expense	\$ 78	20.2 %	\$ 77	20.6 %	\$ 69	20.6 %

(a) The jurisdiction that makes up the majority of state income taxes, net of federal effect, is Kentucky.

Income tax cash payments by federal and state jurisdictions:

	2025	2024	2023
Federal	\$ 67	\$ 62	\$ 71
Kentucky	14	11	13
Total	\$ 81	\$ 73	\$ 84

	2025	2024	2023
Taxes, other than income			
Property and other	\$ 51	\$ 49	\$ 48
Total	\$ 51	\$ 49	\$ 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:

	2025	2024
Deferred Tax Assets		
Contributions in aid of construction	\$ 17	\$ 12
Regulatory liabilities	31	29
Deferred investment tax credits	20	20
Income taxes due to customers	117	124
State tax credit carryforwards	3	4
Lease liabilities	7	6
Other	8	4
Valuation allowances	(1)	(2)
Total deferred tax assets	202	197
Deferred Tax Liabilities		
Plant - net	1,085	1,053
Regulatory assets	56	55
Pension and postretirement costs	8	6
Lease right-of-use assets	7	6
Other	2	1
Total deferred tax liabilities	1,158	1,121
Net deferred tax liability	\$ 956	\$ 924

At December 31, 2025, KU had \$3 million of state credit carryforwards of which \$1 million will expire in 2028 and \$2 million that has an indefinite carryforward period. At December 31, 2025, KU had a \$1 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, income tax cash payments and refunds by federal and state jurisdictions, and details of "Taxes, other than income" were:

	2025	2024	2023
Income Tax Expense (Benefit)			
Current - Federal	\$ 83	\$ 87	\$ 73
Current - State	16	17	13
Total Current Expense (Benefit)	99	104	86
Deferred - Federal	(4)	(15)	(11)
Deferred - State	6	2	4
Total Deferred Expense (Benefit)	2	(13)	(7)
Amortization of investment tax credit - Federal	(2)	(2)	(2)
Total income tax expense (benefit)	\$ 99	\$ 89	\$ 77
Total income tax expense (benefit) - Federal	\$ 77	\$ 70	\$ 60
Total income tax expense (benefit) - State	22	19	17
Total income tax expense (benefit)	\$ 99	\$ 89	\$ 77

	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
Reconciliation of Income Tax Expense (Benefit)						
Taxes at statutory tax rate	\$ 104	21.0 %	\$ 93	21.0 %	\$ 82	21.0 %
Increase (decrease) due to:						
State income taxes, net of federal income tax benefit (a)	19	3.8 %	16	3.7 %	15	3.8 %
Utility rate-making tax adjustment (federal and state):						
Amortization of excess deferred federal and state income taxes	(18)	(3.6) %	(17)	(3.7) %	(17)	(4.3) %
AFUDC Equity	(5)	(1.0) %	(2)	(0.6) %	—	— %
Subtotal	(23)	(4.6) %	(19)	(4.3) %	(17)	(4.3) %
Other	(1)	(0.3) %	(1)	(0.4) %	(3)	(0.7) %
Total decrease	(5)	(1.1) %	(4)	(1.0) %	(5)	(1.2) %
Total income tax expense	\$ 99	19.9 %	\$ 89	20.0 %	\$ 77	19.8 %

(a) The jurisdiction that makes up the majority of state income taxes, net of federal effect, is Kentucky.

Income tax cash payments by federal and state jurisdictions:

	2025	2024	2023
Federal	\$ 78	\$ 85	\$ 65
Kentucky	15	16	12
Other	1	1	1
Total	\$ 94	\$ 102	\$ 78

	2025	2024	2023
Taxes, other than income			
Property and other	\$ 51	\$ 49	\$ 45
Total	\$ 51	\$ 49	\$ 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 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, 2025, 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)	2021 and prior	2021 and prior	n/a	n/a
Kentucky (state)	2020 and prior	2020 and prior	2020 and prior	2020 and prior

Other

One Big Beautiful Bill Act (All Registrants)

On July 4, 2025, President Trump signed into law the One Big Beautiful Bill Act. The Registrants are continuing to review the law to assess any material impacts to the financial statements.

Additionally, on July 7, 2025, President Trump issued an Executive Order directing the Treasury to take action to strictly enforce the termination of clean electricity tax credits under IRC Sections 45Y and 48E for wind and solar. On August 15, 2025, the IRS issued Notice 2025-42, primarily tightening the rules regarding when a solar project is considered to have commenced construction. In addition, the One Big Beautiful Bill Act included new rules addressing Foreign Entities of Concern (FEOC). These rules are supply-chain, foreign entity ownership and debt issuance restrictions that may limit eligibility for certain U.S. clean energy tax credits such as those provided for in IRC Sections 45Y and 48E.

On February 12, 2026, the Treasury and the IRS issued Notice 2026-15, which provides interim guidance on the FEOC restrictions on certain clean electricity tax credits. Additionally, the IRS is expected to issue further guidance on the tax provisions of the One Big Beautiful Bill Act. The Registrants do not currently anticipate these rules or guidance to result in limitations on its clean energy projects and associated tax credits but will continue to monitor closely.

Regulatory Treatment of the TCJA (LG&E)

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, LG&E's deferred taxes were remeasured based upon new federal or state corporate income tax rates. The changes in deferred taxes were 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 Electric and Gas jurisdictions, 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, LG&E 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 Kentucky final order in Case No. 2020-00350, LG&E 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 FERC Jurisdiction, LG&E 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, LG&E established a 15-year amortization period for unprotected excess ADIT in FERC Transmission formula rates.

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 12/31/24 (a)		2025 Amortization of Excess ADIT (b)		Unamortized Net Excess ADIT as of 12/31/25	
Plant Related (c):						
Account 282 - Property Related	\$	346,324,433	\$	14,500,629	\$	331,823,804
Account 282 - Coal Combustion Residual AROs		872,586		52,884		819,702
Account 190 - Net Operating Losses		(17,646,506)		(789,367)		(16,857,139)
Plant Related (c):	\$	329,550,513	\$	13,764,146	\$	315,786,367
Unprotected Non Plant Related:						
Account 190 - Other Temporary Differences	\$	—	\$	—	\$	—
Account 282 - Other Temporary Differences		—		—		—
Account 283 - Other Temporary Differences		—		—		—
Total Unprotected Non Plant Related	\$	—	\$	—	\$	—
Total Excess Deferred Tax	\$	329,550,513	\$	13,764,146	\$	315,786,367
Tax Gross-up Factor				\$		1,33245
Excess Deferred Tax Regulatory Liability				\$		420,767,977
Regulatory Liability on Unamortized Investment Tax Credits (ITC)				\$		9,710,118
Total Tax Regulatory Liability				\$		430,478,095
ASC 740 Regulatory Liability - FERC Form 1 page 278 Difference				\$		430,478,095

(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.

Prior to January 1, 2026, LG&E's and KU's Kentucky base rates were calculated based on 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. Effective January 1, 2026, pursuant to the KPSC rate case, Kentucky base rates are calculated based on a return on rate base (net utility plant plus certain regulatory assets and working capital less accumulated deferred income taxes and certain regulatory liabilities) and include recovery of applicable operations and maintenance expenses.

(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 leveled 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 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	
	2025	2024	2025	2024	2025	2024	2025	2024
Current Regulatory Assets:								
Gas supply clause	\$ 10	\$ 3	\$ —	\$ —	\$ 10	\$ 3	\$ —	\$ —
Rate adjustment mechanisms	86	95	—	—	—	—	—	—
Renewable energy certificates	21	14	—	—	—	—	—	—
Storm damage expense rider	53	68	53	68	—	—	—	—
Transmission service charge	61	44	—	27	—	—	—	—
ISR deferral	6	22	—	—	—	—	—	—
TCJA	40	21	40	21	—	—	—	—
Other	31	53	19	17	9	5	1	1
Total current regulatory assets	\$ 308	\$ 320	\$ 112	\$ 133	\$ 19	\$ 8	\$ 1	\$ 1
Noncurrent Regulatory Assets:								
Defined benefit plans	\$ 961	\$ 967	\$ 477	\$ 473	\$ 212	\$ 226	\$ 144	\$ 149
Plant outage costs	23	30	—	—	5	7	18	23
Net metering	164	147	—	—	—	—	—	—
Environmental cost recovery	102	96	—	—	—	—	—	—
Storm costs	113	113	42	22	24	20	38	29
Unamortized loss on debt	18	20	2	3	8	9	6	6
Terminated interest rate swaps	47	53	—	—	28	31	19	22
Accumulated cost of removal of utility plant	184	173	184	173	—	—	—	—
ARO's	263	280	—	—	73	75	190	205
RAR	76	83	—	—	76	83	—	—
Gas line inspections	24	24	—	—	22	22	2	2
Advanced metering infrastructure	67	28	—	—	28	14	39	14
IT system costs	18	—	18	—	—	—	—	—
Other	32	46	2	2	6	4	11	8
Total noncurrent regulatory assets	\$ 2,092	\$ 2,060	\$ 725	\$ 673	\$ 482	\$ 491	\$ 467	\$ 458
	PPL		PPL Electric		LG&E		KU	
	2025	2024	2025	2024	2025	2024	2025	2024
Current Regulatory Liabilities:								
Generation supply charge	\$ 45	\$ 52	\$ 45	\$ 52	\$ —	\$ —	\$ —	\$ —
Transmission service charge	17	—	17	—	—	—	—	—
Universal service rider	17	3	17	3	—	—	—	—
Transmission formula rate	62	1	23	—	—	—	—	—
Rate adjustment mechanisms	124	71	—	—	—	—	—	—
Energy efficiency	26	25	—	—	—	—	—	—
DSM	21	17	—	—	8	7	13	10
Environmental cost recovery	6	12	—	—	3	6	3	6
Revenue decoupling mechanism	55	10	—	—	—	—	—	—
Other	3	32	1	2	2	1	—	6
Total current regulatory liabilities	\$ 376	\$ 223	\$ 103	\$ 57	\$ 13	\$ 14	\$ 16	\$ 22
Noncurrent Regulatory Liabilities:								
Accumulated cost of removal of utility plant	\$ 1,043	\$ 1,022	\$ —	\$ —	\$ 334	\$ 314	\$ 415	\$ 408
Net deferred taxes	1,798	1,899	708	739	415	439	467	498
Defined benefit plans	342	294	120	100	23	24	69	65
Terminated interest rate swaps	52	54	—	—	26	27	26	27
Advanced metering infrastructure	30	13	—	—	10	4	20	9
Other	53	53	—	—	1	7	—	2
Total noncurrent regulatory liabilities	\$ 3,318	\$ 3,335	\$ 828	\$ 839	\$ 809	\$ 815	\$ 997	\$ 1,009

Following is an overview of selected regulatory assets and liabilities presented 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, 2025, the balances were \$72 million for PPL, \$41 million for LG&E and \$31 million for KU. As of December 31, 2024, the balances were \$79 million for PPL, \$44 million for LG&E and \$35 million for KU.

(PPL)

RIE is subject to a pension rate adjustment mechanism whereby the difference in amounts allowed to be recovered in base rates and the 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 establish or request regulatory assets for expenses related to specific extraordinary storms from the PAPUC, the KPSC and the VSCC, 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 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)

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, 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. 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.

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

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.

IT System Costs

IT system costs represent expenditures incurred associated with implementing strategic information technology investments. As part of the ongoing rate case proceedings, PPL Electric has requested certain of these implementation costs to be treated as capital for ratemaking purposes to be recovered over the useful life of the associated IT asset. Recovery of these costs is subject to approval by the PAPUC, but PPL and PPL Electric believe recovery of these costs is probable.

(PPL, LG&E and KU)

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.

Terminated Interest Rate Swaps

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.

Plant Outage Costs

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 would 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.

Advanced Metering Infrastructure (AMI)

In 2021 base rate case 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, 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, and the remaining net book value of the retired legacy meters replaced by AMI. Additionally, LG&E and KU received approval to record regulatory liabilities comprised of meter reading and field service expense savings since their previous rate case and the cost of capital impact for legacy meters replaced and retired during the AMI implementation. Recovery and/or return of these costs was approved effective January 1, 2026 in the base rate case proceedings.

(PPL)

Energy Efficiency

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.

Net Metering

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.

Rate Adjustment Mechanisms

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.

Renewable Energy Certificates

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.

Environmental Cost Recovery

(PPL, LG&E and KU)

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 opportunity to roll-in ECR amounts to base rates each two-year period. The KPSC has authorized a 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.

(PPL)

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)

Gas Supply Clause

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.

RAR

The RAR rider was established by KPSC orders in 2021 to provide recovery of and return on the retirement costs of 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, 2025 represent the remaining retirement costs of Mill Creek Unit 1 to be recovered through April 2034.

Regulatory Matters

Rhode Island Activities (PPL)

Rate Case Proceeding

On November 26, 2025, RIE filed a request with the RIPUC for an increase in electric and natural gas base distribution rates, and approval of certain regulatory and accounting treatments. In its application, RIE seeks to implement a two-year rate plan. In the first year of the rate plan, RIE's proposed base distribution rates for electric and gas combined are designed to collect additional operating revenue of approximately \$181 million (\$66 million or 18.2% in electricity revenues and \$115 million or 36.4% in gas revenues). In the second year of the rate plan, RIE's proposed base distribution rates for electric and gas combined are designed to collect the proposed base distribution rate increases for electric and gas in the first year of the rate plan and additional operating revenues of approximately \$49 million (\$17 million or 3.6% in electricity revenues and \$32 million or 7.4% in gas revenues).

The application is based on a historical test year of September 1, 2024 through August 31, 2025 and requested an authorized ROE of 10.75%. Subject to RIPUC approval, new rates are expected to become effective on September 1, 2026. Certain counterparties have intervened in the proceeding. A ruling from the RIPUC is anticipated during the third quarter of 2026. PPL cannot predict the outcome of the proceeding.

Hold Harmless Implementation Agreement

As a condition of its approval of the acquisition of RIE in May 2022, the Rhode Island Division of Public Utilities and Carriers required PPL to hold harmless Rhode Island customers from the impact of future rate increases resulting from changes in Accumulated Deferred Income Taxes as a result of the Acquisition (the Hold Harmless Commitment). On June 13, 2025, an agreement was entered into by and among RIE, PPL, PPL Rhode Island Holdings and the Rhode Island Division of Public Utilities and Carriers Advocacy Section (the Hold Harmless Implementation Agreement) to satisfy the Hold Harmless Commitment by providing approximately \$155 million in miscellaneous bill credits issued to customers, with approximately \$74 million to be issued in the first quarter of 2026 and approximately \$81 million to be issued in the first quarter of 2027. The bill credits would be recorded as a reduction to revenue in the periods in which the credits are applied to customers' bills. On September 10, 2025, the Rhode Island Division of Public Utilities and Carriers issued an order confirming that RIE's provision of proposed miscellaneous bill credits as set forth in the Hold Harmless Implementation Agreement would satisfy the Hold Harmless Commitment. Also on September 10, 2025, the RIPUC opened a docket to evaluate the miscellaneous bill credit proposal set forth in the Hold Harmless Implementation Agreement, including the underlying rate accounting, and required RIE to file a tariff advice with the RIPUC, which RIE filed on October 2, 2025. After responding to discovery in that proceeding and before the evidentiary hearing was held or convened, RIE filed a notice of withdrawal of its tariff advice filing noting that it would hold in abeyance a comprehensive satisfaction of the Hold Harmless Commitment at this time. As a result of RIE's filing the notice of withdrawal, the Commission cancelled the evidentiary hearing. The docket remains open, but there has been no further activity since RIE's withdrawal of the tariff advice and the RIPUC's cancellation of the evidentiary hearing. PPL cannot predict whether there will be any further proceedings on the docket or the outcome of any further proceedings that may occur.

Winter Bill Volatility Docket

At an Open Meeting on November 24, 2025, the RIPUC approved several measures to help mitigate winter bill increases for electric customers. First, the RIPUC approved miscellaneous bill credits for all residential electric customers of \$23.54 per month for January, February, and March 2026. Second, the RIPUC paused the Storm Fund Replenishment Factor for usage on and after January 1, 2026, subject to further review through the 2026 Annual Retail Rate Filing. Third, the RIPUC paused the electric Energy Efficiency Charge for usage beginning January 1, 2026 through March 31, 2026. To offset the costs of the miscellaneous bill credits, the RIPUC directed RIE to apply the December 31, 2025 electric Energy Efficiency fund balance, net of any earned incentives, and directed RIE to transfer \$11 million from the storm fund balance. The RIPUC approved future cost recovery for RIE of any unfunded balance of the miscellaneous bill credits through future identified offsets and/or a reconciling recovery mechanism to be determined in conjunction with the 2026 electric retail rate filing to allow recovery by December 31, 2026. Any remaining unfunded balance shall accrue at RIE's weighted average cost of capital.

FY 2026 Gas ISR Plan

On March 28, 2025, the RIPUC approved the FY 2026 Gas ISR Plan of \$165 million, of which \$147 million is for capital investment spend and \$18 million is spend for paving costs as operation and maintenance (O&M), plus a potential additional \$15 million is available if certain regulations are implemented by the PHMSA. On March 31, 2025, the RIPUC approved RIE's compliance filing for rates effective April 1, 2025.

FY 2027 Gas ISR Plan

On December 22, 2025, RIE filed its FY 2027 Gas ISR Plan with the RIPUC with a budget of \$184 million that primarily included \$166 million of capital investment spend and \$17 million for spending on curb-to-curb paving. A decision from the RIPUC on the Plan is expected by March 31, 2026. RIE cannot predict the outcome of this matter.

FY 2026 Electric ISR Plan

On March 28, 2025, the RIPUC approved a FY 2026 Electric ISR Plan of \$219 million for capital investment spend (including \$88 million for Advanced Metering Functionality), \$14 million for vegetation operations and maintenance spend and \$1 million for Other O&M spend. On March 31, 2025, the RIPUC approved RIE's compliance filing for rates effective April 1, 2025.

FY 2027 Electric ISR Plan

On December 22, 2025, RIE filed its FY 2027 Electric ISR Plan with the RIPUC with a budget that primarily included \$154 million of capital investment spend (including \$18 million for Advanced Metering Functionality) and \$13 million of vegetation operation and maintenance spend. A decision from the RIPUC is expected by March 31, 2026. RIE cannot predict the outcome of this matter.

Kentucky Activities

(PPL, LG&E and KU)

Rate Case Proceedings

On May 30, 2025, LG&E and KU filed requests with the KPSC for an increase in annual electricity and gas revenues of approximately \$391 million (\$105 million and \$226 million in electricity revenues at LG&E and KU and \$60 million in gas revenues at LG&E) and approval of certain regulatory and accounting treatments. The revenue increases would be an increase of 8.3% and 11.5% in electricity revenues at LG&E and KU, and an increase of 14.0% in gas revenues at LG&E.

The applications were based on a forecasted test year of January 1, 2026 through December 31, 2026 and requested an authorized ROE of 10.95%. New interim rates became effective on January 1, 2026, subject to refund pursuant to the KPSC's final order. Certain counterparties have intervened in the proceedings.

On October 20, 2025, LG&E and KU filed with the KPSC a stipulation and recommendation (the agreement) regarding a proposed resolution of issues with a majority of the intervenors in the proceedings.

Under the agreement, the parties proposed that the KPSC should issue orders granting a revised increase in annual electricity and gas revenues of approximately \$235 million (\$58 million and \$132 million in electricity revenues at LG&E and KU and \$45 million in gas revenues at LG&E.) The agreement proposed a revised authorized ROE of 9.90%.

The agreement proposed a "stay out" commitment from LG&E and KU to refrain from effective base rate increases before August 1, 2028, subject to certain exceptions. In connection with the stay out period, the agreement also proposed the establishment of two new rate adjustment clause mechanisms, a Generation Cost Recovery Adjustment Clause (GCR) and a Sharing Mechanism Adjustment Clause (SM).

The proposed GCR mechanism would provide LG&E and KU recovery of and return on investment of covered costs (excluding fuel amounts, which LG&E and KU can recover via an existing rate mechanism) of relevant new generation and energy storage assets authorized in the 2022 and 2025 CPCN proceedings (excluding the Mill Creek Unit 6 NGCC, see "2025 CPCN" for more information regarding the Mill Creek Unit 6 NGCC) as they are placed in service.

The proposed SM mechanism would address any base rate revenue deficiency or surplus during the final thirteen months of the stay out period, July 2027 through July 2028, below or above a suggested ROE band of 9.40% to 10.15%. Any such base rate revenue deficiency or surplus would be collected from or returned to customers over a thirteen-month billing period beginning November 2028.

Following issuance of the 2025 CPCN Order, LG&E and KU filed supplemental testimony with the KPSC in the rate case proceedings seeking recovery of the Mill Creek Unit 2 stay open costs through a proposed additional rate adjustment clause mechanism. The agreement further proposed that LG&E and KU use regulatory deferral accounting for actual expenses above or below base rate levels for certain expenses including: pension and post-retirement benefits, storm restoration, vegetation management, transmission waivers and credits, and gas line or well activities, with recovery of such deferred asset or liability amounts to be addressed in future rate cases.

On February 16, 2026, the KPSC issued orders approving portions of the October 2025 stipulation and recommendation, with modifications.

The KPSC orders provide for increases in annual electricity and gas revenues of \$233 million (\$59 million and \$128 million in electricity revenues at LG&E and KU and \$46 million in gas revenues at LG&E.) The orders include authorized returns on equity of 9.775% for base rate purposes and 9.675% for capital rate adjustment mechanisms.

The KPSC orders approve LG&E's and KU's requests for establishment of certain new rate adjustment mechanisms or tariffs, with modifications:

- a temporary Pilot Generation Recovery Adjustment Clause (PGR) to provide recovery of and return on investment of applicable costs of certain new generation and storage assets being built or anticipated to be built by LG&E and KU as authorized in the 2022 CPCN proceeding;
- the inclusion in the PGR of recovery of and return on investment of certain costs associated with a potential extension of the operating life of LG&E's Mill Creek Unit 2 beyond its original 2027 retirement date; and
- an Extremely High Load Factor Tariff for future applicable customers, such as data centers, which includes requirements such as long-term contracts, minimum revenue payments and collateral security structures that help protect the interests of LG&E, KU and of other ratepayers.

The PGR mechanism is similar to the GCR proposed in the stipulation, but restructured by the KPSC to be a pilot adjustment mechanism with a term until the earlier of ten months following the submission of LG&E's and KU's next base rate proceeding or the effective date of new rates in such proceeding, with the expectation that the mechanism would be reviewed in such proceeding. The pilot mechanism will apply to the planned Mill Creek Unit 5, Brown Battery Energy Storage System, Mercer County Solar and Marion County Solar generation-related projects. The KPSC also included Mill Creek Unit 2's potential stay-open costs in the PGR in lieu of approving the stipulation's request for a stand-alone adjustment mechanism for such costs. Finally, the KPSC excluded from coverage under the PGR costs related to Mill Creek Unit 6 and Brown Unit 12 planned new generation assets due to their anticipated in-service dates falling outside of the estimated pilot mechanism's duration, but without prejudice to LG&E and KU seeking recovery of such costs in future proceedings.

The KPSC orders also approved, approved with modifications, or denied in some cases, other requested accounting and rate matters relating to regulatory assets or liabilities, depreciation rates, and other areas.

The rate changes have a retroactive effective date as of January 1, 2026. Consistent with authorized rate case procedures, LG&E and KU will refund to customers amounts billed in excess of the final approved rates within sixty days.

The KPSC orders did not approve the SM adjustment clause that had been requested in the stipulation and made no modifications to the stay out offer by LG&E and KU to refrain from effective base rate increases prior to August 2028.

LG&E and KU and all intervenors have rights to request rehearing or appeal of the orders of the KPSC and because the KPSC orders modified or denied terms of the proposed stipulation, LG&E and KU and all stipulating parties have the right to withdraw from the stipulation.

LG&E and KU continue to evaluate the details contained in the orders and related matters as they consider next steps. PPL, LG&E and KU cannot predict the outcome of this matter.

2025 CPCN

On February 28, 2025, LG&E and KU filed an application with the KPSC regarding certain future plans for new generation and generation-related construction matters. The proposals included in the application were intended to serve anticipated load growth, including from potential data center demand in LG&E's or KU's service territory. The proposals did not include retirements of coal or other fossil-fueled plants, which would require additional KPSC approval procedures under Kentucky legislation enacted in 2023 and 2024.

LG&E and KU submitted a joint application to the KPSC for approval of certain certificates of public 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 were expected to be \$3.7 billion. The application included proposals to build:

- a 645 MW NGCC generation unit at KU's E.W. Brown station (Brown Unit 12),
- a 645 MW NGCC generation unit at LG&E's Mill Creek station (Mill Creek Unit 6),
- a four-hour 400 MW (1600 MWh total) battery energy storage system (BESS) at LG&E's Cane Run station, and
- a selective catalytic reduction (SCR) environmental facility at KU's Ghent station Unit 2 (Ghent Unit 2).

The new NGCC units are anticipated to be wholly owned by LG&E and the BESS unit jointly owned by LG&E (32%) and KU (68%), 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 proposed Mill Creek Unit 6 NGCC is in addition to a new NGCC unit currently under construction at that location (Mill Creek Unit 5).

The filing also noted projected in service dates for the projects, including the Brown Unit 12 NGCC in 2030, the Mill Creek Unit 6 NGCC in 2031, the Cane Run BESS in 2028 and the Ghent Unit 2 SCR in 2028.

On July 29, 2025, LG&E and KU filed with the KPSC a stipulation and recommendation regarding a proposed resolution of issues with several of the intervenors in the CPCN proceeding (stipulation). The stipulation recommended to the KPSC the approval of the large majority of LG&E's and KU's requested generation-related projects and associated accounting matters, subject to certain changes. Under the stipulation, the parties agreed the KPSC should issue an order granting a CPCN for the proposed: (a) Brown Unit 12 NGCC; (b) Mill Creek Unit 6 NGCC; and (c) Ghent Unit 2 SCR. In addition, the proposal to build the \$775 million Cane Run BESS would be withdrawn without prejudice, the relevant costs regarding the proposed \$1.4 billion Mill Creek Unit 6 NGCC would be recovered through a new rate adjustment clause mechanism, the retirement date for the existing Mill Creek Unit 2 coal unit would be extended from 2027 to the operational date of the proposed Mill Creek Unit 6 NGCC or afterwards, subject to relevant future economic analysis, regulatory or environmental authorizations, and the relevant costs to continue to operate the Mill Creek Unit 2 coal unit would be recovered through a new rate adjustment clause mechanism. The stipulation also contained provisions relating to regulatory asset accounting, proposed data center tariffs, future renewable power requests-for-proposals and other matters. LG&E and KU would retain the right to seek approval of the potentially withdrawn Cane Run BESS or similar substitute project in future regulatory proceedings.

On October 28, 2025, the KPSC issued an order approving much of LG&E's and KU's July 2025 stipulation, with certain modifications. The order granted the requested CPCNs and site-related permits to construct the proposed Brown Unit 12 NGCC, Mill Creek Unit 6 NGCC, and Ghent Unit 2 SCR. The order authorized inclusion of relevant costs of the Ghent Unit 2 SCR in KU's existing environmental cost recovery rate mechanism. The order established a separate monitoring case to receive and consider information during the construction of Mill Creek Unit 6 NGCC.

The order approved requests regarding regulatory asset deferral accounting treatment for certain AFUDC related amounts and noted the KPSC's expectation that the stipulating parties would follow through with their commitments regarding tariffs and power supply contracts related to potential future data center or high load customers in LG&E's and KU's pending rate proceedings. The order also approved other elements of the stipulation or the originally-filed application, with minor modifications.

The KPSC decided not to approve LG&E's and KU's proposed new rate adjustment cost recovery mechanisms for certain costs associated with Mill Creek Unit 6 NGCC and costs associated with operating the Mill Creek Unit 2 coal plant beyond its original retirement date in 2027. However, the denials were without prejudice to resubmission and the KPSC encouraged the parties to provide additional evidence on such matters in separate proceedings. LG&E and KU provided such evidence addressing recovery of the Mill Creek Unit 2 stay open costs in their pending rate case proceedings. Recovery of Mill Creek Unit 6 costs will be addressed in a future proceeding. The KPSC declined to rule on the matter related to the retirement date of Mill Creek Unit 2 coal plant. The KPSC indicated that a request for a new retirement approval proceeding may be required should LG&E elect to operate Mill Creek Unit 2 beyond its existing approved retirement date and seek to later retire the unit.

In light of the conditional withdrawal in the stipulation, the order did not include a CPCN for the Cane Run BESS. LG&E and KU retain the right to seek approval of the Cane Run BESS project or similar substitute projects at any time in future regulatory proceedings.

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 (O&M) expenses portion of the costs incurred related to the storm. On March 19, 2025, the KPSC issued an order authorizing LG&E and KU to establish, for accounting purposes only, regulatory assets based on the jurisdictional incremental costs of extraordinary O&M expense incurred by LG&E and KU as a result of the 2025 winter storm, with recovery amounts and amortization thereof to be determined in subsequent base rate proceedings. LG&E and KU cannot predict the outcome of these matters. As of December 31, 2025, LG&E and KU had recorded regulatory assets related to the storm of \$2 million and \$7 million.

Mill Creek Unit 1 and Unit 2 RAR Application (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. On February 24, 2025, the KPSC issued an order approving LG&E's cost recovery for Mill Creek Unit 1 under the RAR of \$125 million and related amounts were included in bills beginning in May 2025.

LG&E anticipates the recovery of associated costs, including the remaining net book value, for Mill Creek Unit 2 through the RAR. The remaining net book value of Mill Creek Unit 2 was approximately \$199 million at December 31, 2025 and LG&E is continuing to depreciate using the current approved rates through its retirement date. LG&E expects to reclassify the net book value remaining at retirement to a regulatory asset to be amortized over a period of ten years in accordance with the RAR. There can be no assurance that these costs will be recovered in the amounts or over the time periods that LG&E expects. See the "2025 CPCN" and "Rate Case Proceedings" discussions above for information regarding potential changes in the retirement date of Mill Creek Unit 2.

Pennsylvania Activities (PPL and PPL Electric)

Rate Case Proceeding

On September 30, 2025, PPL Electric filed a request with the PAPUC for an increase in distribution base rates of approximately \$356 million, more than \$50 million of which is already included in customer bills through rate recovery mechanisms, and approval of certain regulatory and accounting treatments. The proposed increase in distribution base rates would increase PPL Electric's total annual revenue by approximately 8.6%. The application is based on a fully projected future test year of July 1, 2026 through June 30, 2027 and requested an authorized ROE of 11.3%. Subject to PAPUC approval, new rates are expected to become effective on July 1, 2026. Certain counterparties have intervened in the proceeding. A ruling from the PAPUC is anticipated during the second quarter of 2026. PPL and PPL Electric cannot predict the outcome of the proceeding.

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 February 28, 2025, the PAPUC issued its written order permitting PPL Electric to increase its DSIC cap from 5% to 7.5% for bills rendered on or after March 13, 2025 until the effective date of rates established in PPL Electric's next base rate case or the end of the PPL Electric's 2023-2027 Long-term Infrastructure Improvement Plan, whichever occurs first, at which time it will return to 5%.

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. On August 8, 2025, the D.C. Circuit Court of Appeals issued a procedural ruling vacating the FERC's prior orders and remanded the matter back to the FERC for further proceedings. 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 existing base rate levels.

Recovery of Transmission Costs (PPL)

NE-ISO allocates RIE's costs among transmission customers in New England, in accordance with the ISO Open Access Transmission Tariff (ISO-NE OATT).

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 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 RIPUC-approved and PAPUC-approved purchase of accounts receivable programs, RIE and PPL Electric purchase 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 2025, 2024 and 2023, RIE purchased \$314 million, \$299 million and \$235 million of accounts receivable from alternative suppliers.

During 2025, 2024 and 2023, PPL Electric purchased \$1.6 billion, \$1.5 billion and \$1.5 billion of accounts receivable from alternative suppliers.

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:

	December 31, 2025				December 31, 2024		
	Expiration Date	Capacity	Borrowed	Letters of Credit and Commercial Paper Issued (a)	Unused Capacity	Borrowed	Letters of Credit and Commercial Paper Issued (a)
PPL							
PPL Capital Funding (b)							
Syndicated Credit Facility (c)(d)(e)	Dec. 2029	\$ 1,500	\$ —	\$ 456	\$ 1,044	\$ —	\$ 138
Bilateral Credit Facility (c)(d)	Feb. 2026	100	—	—	100	—	—
Bilateral Credit Facility (c)(d)	Feb. 2026	100	—	17	83	—	15
Total PPL Capital Funding Credit Facilities		\$ 1,700	\$ —	\$ 473	\$ 1,227	\$ —	\$ 153
PPL Electric							
Syndicated Credit Facility (c)(d)	Dec. 2029	750	—	6	744	—	1
Total PPL Electric Credit Facilities		\$ 750	\$ —	\$ 6	\$ 744	\$ —	\$ 1
LG&E							
Syndicated Credit Facility (c)(d)	Dec. 2029	600	—	—	600	—	25
Total LG&E Credit Facilities		\$ 600	\$ —	\$ —	\$ 600	\$ —	\$ 25
KU							
Syndicated Credit Facility (c)(d)	Dec. 2029	600	—	—	600	—	140
Total KU Credit Facilities		\$ 600	\$ —	\$ —	\$ 600	\$ —	\$ 140

(a) Commercial paper issued reflects the undiscounted face value of the issuance.
(b) PPL Capital Funding's obligations are fully and unconditionally guaranteed by PPL.
(c) 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.

- (d) 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 2026 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.
- (e) Includes a \$400 million borrowing sublimit for RIE and a \$1.1 billion sublimit for PPL Capital Funding at December 31, 2025 and a \$250 million borrowing sublimit for RIE and a \$1 billion sublimit for PPL Capital Funding at December 31, 2024. At December 31, 2025, PPL Capital Funding had \$355 million of commercial paper outstanding and RIE had \$101 million commercial paper outstanding. At December 31, 2024, PPL Capital Funding had \$138 million of commercial paper outstanding and RIE had no commercial paper outstanding. RIE's obligations under the facility are not guaranteed by PPL.

(PPL)

In January 2026, PPL Capital Funding amended its existing \$1.50 billion syndicated credit facility to extend the termination date of certain commitments from December 6, 2029 to December 6, 2030.

(PPL and PPL Electric)

In January 2026, PPL Electric amended its existing \$750 million syndicated credit facility to extend the termination date of certain commitments from December 6, 2029 to December 6, 2030.

(PPL and LG&E)

In January 2026, LG&E amended its existing \$600 million syndicated credit facility to extend the termination date of certain commitments from December 6, 2029 to December 6, 2030.

(PPL and KU)

In January 2026, KU amended its existing \$600 million syndicated credit facility to extend the termination date of certain commitments from December 6, 2029 to December 6, 2030.

(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, 2025				December 31, 2024	
	Weighted - Average Interest Rate	Capacity	Commercial Paper Issuances (a)	Unused Capacity	Weighted - Average Interest Rate	Commercial Paper Issuances (a)
PPL Capital Funding (b)(c)	4.16%	\$ 1,600	\$ 355	\$ 1,245	4.76%	\$ 138
RIE (c)	4.21%	400	101	299	—	—
PPL Electric		750	—	750	—	—
LG&E		600	—	600	4.72%	25
KU		600	—	600	4.71%	140
Total		\$ 3,950	\$ 456	\$ 3,494		\$ 303

(a) Commercial paper issued reflects the undiscounted face value of the issuance.

(b) PPL Capital Funding's obligations are fully and unconditionally guaranteed by PPL.

(c) 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, 2025, had a total capacity of \$1.50 billion, with a \$400 million borrowing sublimit for RIE and a \$1.1 billion sublimit for PPL Capital Funding. At December 31, 2024, the borrowing sublimits were \$250 million for RIE and \$1 billion for 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 \$1.50 billion. PPL Capital Funding's commercial paper program is also backed by a separate bilateral credit facility for \$100 million.

(PPL Electric, LG&E and KU)

See Note 13 for a discussion of intercompany borrowings.

Long-term Debt (All Registrants)

			December 31,	
	Weighted-Average Rate (d)	Maturities (d)	2025	2024
<u>PPL</u>				
Senior Unsecured Notes	4.34 %	2026 - 2047	\$ 4,316	\$ 4,316
Senior Secured Notes/First Mortgage Bonds (a)(b)(c)	4.64 %	2026 - 2055	12,227	10,878
Exchangeable Senior Unsecured Notes	2.94 %	2028 - 2030	2,150	1,000
Junior Subordinated Notes	6.61 %	2067	480	480
Total Long-term Debt before adjustments			19,173	16,674
Long-term Debt, repurchased affiliate bonds			(84)	—
Unamortized premium and (discount), net			(58)	(57)
Unamortized debt issuance costs			(137)	(114)
Total Long-term Debt			18,894	16,503
Less current portion of Long-term Debt			904	551
Total Long-term Debt, noncurrent			\$ 17,990	\$ 15,952
<u>PPL Electric</u>				
Senior Secured Notes/First Mortgage Bonds (a)(b)	4.72 %	2027 - 2055	\$ 5,799	\$ 5,299
Total Long-term Debt Before Adjustments			5,799	5,299
Unamortized discount			(45)	(42)
Unamortized debt issuance costs			(47)	(43)
Total Long-term Debt			5,707	5,214
Less current portion of Long-term Debt			—	—
Total Long-term Debt, noncurrent			\$ 5,707	\$ 5,214
<u>LG&E</u>				
Senior Secured Notes/First Mortgage Bonds (a)(c)	4.52 %	2026 - 2055	\$ 2,889	\$ 2,489
Total Long-term Debt Before Adjustments			2,889	2,489
Unamortized discount			(4)	(4)
Unamortized debt issuance costs			(20)	(14)
Total Long-term Debt			2,865	2,471
Less current portion of Long-term Debt			90	300
Total Long-term Debt, noncurrent			\$ 2,775	\$ 2,171
<u>KU</u>				
Senior Secured Notes/First Mortgage Bonds (a)(c)	4.60 %	2026 - 2055	\$ 3,539	\$ 3,089
Total Long-term Debt Before Adjustments			3,539	3,089
Unamortized premium			4	4
Unamortized discount			(8)	(8)
Unamortized debt issuance costs			(25)	(19)
Total Long-term Debt			3,510	3,066
Less current portion of Long-term Debt			164	250
Total Long-term Debt, noncurrent			\$ 3,346	\$ 2,816

(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 \$14.6 billion and \$13.3 billion at December 31, 2025 and 2024.

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 \$6.4 billion and \$6.0 billion at December 31, 2025 and 2024.

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 \$8.0 billion and \$7.5 billion at December 31, 2025 and 2024.

(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 made 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, 2025, 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, 2025, 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, 2025.

The aggregate maturities of long-term debt, based on sinking fund requirements, stated maturities or earlier put dates, for the periods 2026 through 2030 and thereafter are as follows:

	PPL (a)	PPL Electric	LG&E	KU
2026	\$ 904	\$ —	\$ 90	\$ 164
2027	428	108	260	60
2028	1,350	—	—	—
2029	116	116	—	—
2030	2,181	—	—	—
Thereafter	14,110	5,575	2,539	3,315
Total	\$ 19,089	\$ 5,799	\$ 2,889	\$ 3,539

- (a) Reduced by \$84 million of repurchased affiliate bonds as of December 31, 2025. See "Open Market Repurchase Program" below for additional information.

Exchangeable Notes

(PPL)

In November 2025, PPL Capital Funding issued \$1.15 billion of 3.000% Exchangeable Senior Notes due 2030 (the Notes). PPL Capital Funding received proceeds of \$1.14 billion, net of underwriting fees, which were used to repay short-term debt and for general corporate purposes. The Notes are senior unsecured obligations of PPL Capital Funding, fully and unconditionally guaranteed on a senior unsecured basis by PPL. The Notes are scheduled to mature on December 1, 2030, unless earlier exchanged, redeemed or repurchased.

The Notes are exchangeable at an initial exchange rate of approximately 23.44 shares of PPL's common stock per \$1,000 principal amount (equivalent to an initial exchange price of approximately \$42.66 per share of common stock). The initial exchange rate is subject to adjustment, as provided in the indenture for anti-dilutive events and fundamental change and redemption provisions. Upon exchange of the Notes, PPL Capital Funding expects to redeem the aggregate principal amount of the Notes in cash. PPL Capital Funding will pay cash, deliver shares of common stock or a combination of cash and shares of common stock, at PPL Capital Funding's election, in respect of the remainder, if any, of its exchange obligation in excess of the aggregate principal amount of the Notes being exchanged. Prior to the close of business on the business day immediately preceding September 1, 2030, the Notes will be exchangeable at the option of the noteholders only upon the satisfaction of specified conditions and during certain periods described in the indenture pursuant to which the Notes were issued. On or after the close of business on the business day immediately preceding September 1, 2030 until the maturity date, the Notes will be exchangeable at the option of the noteholders at any time regardless of these conditions or periods.

PPL Capital Funding may not redeem the Notes prior to December 5, 2028. PPL Capital Funding may redeem for cash all or any portion of the Notes, at its option, on or after December 5, 2028, if the last reported sale price of the common stock has been at least 130% of the exchange price then in effect for at least 20 trading days (whether or not consecutive), during any 30 consecutive trading day period, at a redemption price equal to 100% of the principal amount of the Notes to be redeemed, plus any accrued and unpaid interest to, but excluding, the redemption date. No sinking fund is provided for the Notes.

Subject to certain conditions, holders of the Notes will have the right to require PPL Capital Funding to repurchase all or a portion of their Notes upon the occurrence of a fundamental change, as defined in the indenture pursuant to which the Notes were issued at a repurchase price of 100% of their principal amount plus any accrued and unpaid interest. In connection with certain corporate events or if PPL Capital Funding calls any Notes for redemption, PPL Capital Funding will, under certain circumstances, increase the exchange rate for noteholders who elect to exchange their Notes in connection with any such corporate event or exchange their Notes called for redemption.

Open Market Repurchase Program

In the fourth quarter of 2025, PPL repurchased \$84 million of affiliate bonds that included \$36 million of PPL Electric bonds, \$8 million of LG&E bonds and \$40 million of KU bonds. On a consolidated basis, PPL's repurchases have been accounted for as debt extinguishments and resulted in a pre-tax gain of \$18 million, net of unmortized debt issuance fees and discounts, which has been recorded as a reduction of Interest Expense on PPL's Consolidated Statements of Income. Intercompany interest expense related to the repurchased bonds was immaterial for the year ended December 31, 2025.

First Mortgage Bond Issuances

(PPL and PPL Electric)

In August 2025, PPL Electric issued \$500 million of 5.55% First Mortgage Bonds due 2055. PPL Electric received proceeds of \$491 million, net of discounts and underwriting fees, to be used to repay short-term debt and for other general corporate purposes.

(PPL and LG&E)

In August 2025, LG&E issued \$700 million of 5.85% First Mortgage Bonds due 2055. LG&E received proceeds of \$694 million, net of discounts and underwriting fees, to be used to repay short-term debt, the current portion of certain long-term debt and for other general corporate purposes.

(PPL and KU)

In August 2025, KU issued \$700 million of 5.85% First Mortgage Bonds due 2055. KU received proceeds of \$694 million, net of discounts and underwriting fees, to be used to repay short-term debt, the current portion of certain long-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)

Equity Securities

ATM Program

In February 2025, PPL entered into an equity distribution agreement, pursuant to which PPL may sell, from time to time, up to an aggregate of \$2 billion of its common stock through an ATM Program, which may utilize an optional forward sales component. Each forward contract under the agreement must be settled within 24 months. The compensation paid to the selling agents by PPL may be up to 2% of the gross offering proceeds of the shares. As of December 31, 2025, PPL had entered into forward contracts to sell approximately 38.7 million shares of its common stock at a blended initial forward price of approximately \$35.62 per share. The forward sale price may be adjusted based on changes in daily interest rates, for certain stock loan fees as determined by a third-party agent, and will be subject to predetermined reductions based on expected dividends. Each outstanding forward contract must be settled on or before dates ranging from December 30, 2025 to August 11, 2027. PPL may elect, at its discretion, to physically settle, net share settle or net cash settle the forward contracts. On December 29, 2025, PPL settled forward sale contracts with physical delivery of approximately 11.3 million shares of common stock for proceeds of approximately \$394 million, net of issuance fees. At December 31, 2025, PPL could have settled the remaining forward sale contracts with physical delivery of approximately 27.4 million shares of common stock for proceeds of approximately \$981 million. The forward contracts under the ATM program are classified as equity transactions.

Distributions and Related Restrictions

In November 2025, PPL declared its quarterly common stock dividend, payable January 2, 2026, at 27.25 cents per share (equivalent to \$1.09 per annum). On February 20, 2026, PPL announced a quarterly common stock dividend of 28.50 cents per share, payable April 1, 2026, to shareholders of record as of March 10, 2026. 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, 2025, no interest payments were deferred.

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.

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 and \$228 million were incurred for the years ended December 31, 2024 and 2023. 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, and \$7 million for the years ended December 31, 2024 and 2023.

As a condition to the Acquisition, 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) severance payments, communications and branding changes, and other transition related costs. These costs, which are being expensed as incurred, were \$71 million, \$307 million, and \$262 million for the years ended December 31, 2025, 2024, and 2023.

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 645 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.

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 were closed to new salaried employees in 2012 and bargaining unit employees in 2013. Employees hired after the defined benefit plans were closed receive additional company contributions above the standard matching contributions to their savings plans.

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		
	2025	2024	2023	2025	2024	2023
Net periodic defined benefit costs (credits):						
Service cost	\$ 31	\$ 35	\$ 34	\$ 6	\$ 6	\$ 6
Interest cost	185	183	188	30	29	30
Expected return on plan assets	(287)	(299)	(309)	(30)	(30)	(30)
Amortization of:						
Prior service cost (credit)	—	3	6	2	1	1
Actuarial (gain) loss	18	10	2	(4)	(5)	(5)
Net periodic defined benefit costs (credits)	\$ (53)	\$ (68)	\$ (79)	\$ 4	\$ 1	\$ 2
Other Changes in Plan Assets and Benefit Obligations Recognized in OCI and Regulatory Assets/Liabilities - Gross:						
Net (gain) loss	\$ 27	\$ 134	\$ 193	\$ —	\$ 1	\$ (6)
Prior service cost (credit)	(5)	(13)	2	2	—	—
Amortization of:						
Prior service (cost) credit	—	(3)	(6)	(2)	(1)	(1)
Actuarial gain (loss)	(18)	(10)	(2)	4	5	5
Total recognized in OCI and regulatory assets/liabilities	4	108	187	4	5	(2)
Total recognized in net periodic defined benefit costs, OCI and regulatory assets/liabilities	\$ (49)	\$ 40	\$ 108	\$ 8	\$ 6	\$ —

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		
	2025	2024	2023	2025	2024	2023
OCI	\$ 21	\$ 25	\$ 52	\$ 2	\$ 2	\$ —
Regulatory assets/liabilities	(17)	83	135	2	3	(2)
Total recognized in OCI and regulatory assets/liabilities	\$ 4	\$ 108	\$ 187	\$ 4	\$ 5	\$ (2)

(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.

PPL	Pension Benefits		Other Postretirement Benefits	
	2025	2024	2025	2024
Discount rate	5.72 %	5.93 %	5.74 %	5.91 %
Rate of compensation increase	3.43 %	3.43 %	3.43 %	3.44 %

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

PPL	Pension Benefits			Other Postretirement Benefits		
	2025	2024	2023	2025	2024	2023
Discount rate	5.93 %	5.52 %	5.52 %	5.91 %	5.54 %	5.54 %
Rate of compensation increase	3.43 %	3.43 %	3.43 %	3.44 %	3.43 %	3.43 %
Expected return on plan assets (a)	8.25 %	8.25 %	8.25 %	7.27 %	7.28 %	7.38 %

(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:

	2025	2024	2023
PPL			
Health care cost trend rate assumed for next year			
– obligations	7.50 %	7.00 %	6.25 %
– cost	7.00 %	6.25 %	6.50 %
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)			
– obligations	4.50 %	5.00 %	5.00 %
– cost	5.00 %	5.00 %	5.00 %
Year that the rate reaches the ultimate trend rate			
– obligations	2038	2033	2029
– cost	2033	2029	2029

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

	Pension Benefits		Other Postretirement Benefits	
	2025	2024	2025	2024
Change in Benefit Obligation				
Benefit Obligation, beginning of period	\$ 3,244	\$ 3,454	\$ 523	\$ 538
Service cost	31	35	6	6
Interest cost	185	183	30	29
Participant contributions	—	—	8	8
Plan amendments	(5)	(13)	1	—
Actuarial (gain) loss	77	(131)	20	(4)
Gross benefits paid	(297)	(284)	(51)	(56)
Federal subsidy	—	—	—	2
Benefit Obligation, end of period	3,235	3,244	537	523
Change in Plan Assets				
Plan assets at fair value, beginning of period	2,936	3,176	417	438
Actual return on plan assets	338	34	51	25
Employer contributions	10	10	11	14
Participant contributions	—	—	7	7
Transfer out (a)	—	—	—	(13)
Gross benefits paid	(297)	(284)	(54)	(54)
Plan assets at fair value, end of period	2,987	2,936	432	417
Funded Status, end of period	\$ (248)	\$ (308)	\$ (105)	\$ (106)
Amounts recognized in the Balance Sheets consist of:				
Noncurrent asset	\$ 44	\$ 19	\$ 9	\$ 8
Current liability	(11)	(10)	(10)	(13)
Noncurrent liability	(281)	(317)	(104)	(101)
Net amount recognized, end of period	\$ (248)	\$ (308)	\$ (105)	\$ (106)
Amounts recognized in AOCI and regulatory assets/liabilities (pre-tax) consist of:				
Prior service cost (credit)	\$ (11)	\$ (6)	\$ 8	\$ 9
Net actuarial (gain) loss	1,173	1,164	(86)	(90)
Total	\$ 1,162	\$ 1,158	\$ (78)	\$ (81)
Total accumulated benefit obligation for defined benefit pension plans	\$ 3,105	\$ 3,116		

(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	
	2025	2024	2025	2024
AOCI	\$ 304	\$ 283	\$ 18	\$ 16
Regulatory assets/liabilities	858	875	(96)	(97)
Total	\$ 1,162	\$ 1,158	\$ (78)	\$ (81)

The actuarial loss for pension plans in 2025 was primarily related to a change in the discount rate used to measure the benefit obligations of those plans. The actuarial gain for pension plans in 2024 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	
	2025	2024
Projected benefit obligation	\$ 2,704	\$ 2,719
Fair value of plan assets	2,412	2,392
	ABO in excess of plan assets	
	2025	2024
Accumulated benefit obligation	\$ 2,600	\$ 2,618
Fair value of plan assets	2,412	2,392

(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:

	2025	2024
Pension	\$ (62)	\$ (83)
Other postretirement benefits	(53)	(60)

(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:

	2025	2024
Pension	\$ 46	\$ 29
Other postretirement benefits	(46)	(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.

	2025	2024
Pension	\$ 56	\$ 46
Other postretirement benefits	(10)	(8)

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 2025 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		2025	
	2025	2024	Target Asset Allocation	
Growth Portfolio	55 %	55 %	55 %	
Equity securities	30 %	30 %		
Debt securities (a)	13 %	13 %		
Alternative investments	12 %	12 %		
Immunizing Portfolio	43 %	43 %	43 %	
Debt securities (a)	31 %	35 %		
Derivatives (b)	12 %	8 %		
Liquidity Portfolio	2 %	2 %	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, 2025				December 31, 2024			
	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	\$ 239	\$ 239	\$ —	\$ —	\$ 212	\$ 212	\$ —	\$ —
Equity securities:								
U.S. Equity	69	69	—	—	63	63	—	—
U.S. Equity fund measured at NAV (a)	469	—	—	—	461	—	—	—
International equity fund measured at NAV (a)	375	—	—	—	376	—	—	—
Commingled debt measured at NAV (a)	464	—	—	—	461	—	—	—
Debt securities:								
U.S. Treasury and U.S. government sponsored agency	273	273	—	—	150	149	1	—
Corporate	753	—	742	11	867	—	848	19
Other	7	—	7	—	13	—	13	—
Alternative investments:								
Real estate measured at NAV (a)	71	—	—	—	72	—	—	—
Private equity measured at NAV (a)	122	—	—	—	114	—	—	—
Private credit partnerships measured at NAV (a)	20	—	—	—	16	—	—	—
Hedge funds measured at NAV (a)	179	—	—	—	181	—	—	—
Derivatives	(7)	—	(7)	—	(38)	—	(38)	—
PPL Services Corporation Master Trust assets, at fair value	3,034	\$ 581	\$ 742	\$ 11	2,948	\$ 424	\$ 824	\$ 19
Receivables and payables, net (b)	69				102			
401(h) accounts restricted for other postretirement benefit obligations	(116)				(114)			
Total PPL Services Corporation Master Trust pension assets	\$ 2,987				\$ 2,936			

(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, 2025 is as follows:

	Corporate debt
Balance at beginning of period	\$ 19
Actual return on plan assets:	
Relating to assets sold during the period	(1)
Purchases, sales and settlements	(7)
Balance at end of period	\$ 11

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

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 within the fair value hierarchy, however, the debt funds are treated as fixed income for asset allocation and target allocation purposes. 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, 2025, the Master Trust had unfunded commitments of \$49 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 within the fair value hierarchy, 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.

Asset Class	Percentage of plan assets		Target Asset Allocation
	2025	2024	2025
Equity securities	46 %	45 %	45 %
Debt securities (a)	48 %	49 %	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, 2025				December 31, 2024			
	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	\$ —	\$ —	\$ 19	\$ 19	\$ —	\$ —
Equity securities:								
Large-cap equity fund measure at NAV (a)	75	—	—	—	71	—	—	—
Commingled debt fund measured at NAV (a)	82	—	—	—	78	—	—	—
Global equity exchange-traded fund	74	74	—	—	70	70	—	—
Long-term bond exchange-traded fund	75	75	—	—	74	74	—	—
Total VEBA trust assets, at fair value	325	\$ 168	\$ —	\$ —	312	\$ 163	\$ —	\$ —
Receivables and payables, net (b)	(9)				(9)			
401(h) account assets	116				114			
Total other postretirement benefit plan assets	\$ 432				\$ 417			

- (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 2026, 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 \$11 million of benefit payments under these plans in 2026.

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 \$10 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
2026	\$ 307	\$ 50	\$ —
2027	294	49	—
2028	287	49	—
2029	279	48	—
2030	272	48	—
2031-2035	1,271	224	—

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:

	2025	2024	2023
PPL	\$ 60	\$ 53	\$ -48
PPL Electric	10	9	8
LG&E	10	8	8
KU	8	6	6

11. Jointly Owned Facilities

(PPL, LG&E and KU)

At December 31, 2025 and 2024, 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, 2025				
Trimble County Unit 1	75.00 %	\$ 464	\$ 141	\$ 20
Trimble County Unit 2	75.00 %	1,543	344	20
December 31, 2024				
Trimble County Unit 1	75.00 %	\$ 462	\$ 124	\$ 1
Trimble County Unit 2	75.00 %	1,549	323	10
LG&E				
December 31, 2025				
E.W. Brown Units 6-7	38.00 %	\$ 53	\$ 31	\$ —
Paddy's Run Unit 13 & E.W. Brown Unit 5	53.00 %	52	32	—
Trimble County Unit 1	75.00 %	464	141	20
Trimble County Unit 2	14.25 %	474	88	9
Trimble County Units 5-6	29.00 %	37	20	—
Trimble County Units 7-10	37.00 %	82	44	2
Cane Run Unit 7	22.00 %	137	31	2
E.W. Brown Solar Unit	39.00 %	10	4	—
Solar Share	44.00 %	3	1	—
Mercer Solar	37.00 %	7	—	14
Mill Creek Unit 5	31.00 %	1	—	219
Brown Wind	36.00 %	—	—	—
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 Unit 5	31.00 %	—	—	74
Brown Wind	36.00 %	—	—	—
KU				
December 31, 2025				
E.W. Brown Units 6-7	62.00 %	\$ 88	\$ 51	\$ —
Paddy's Run Unit 13 & E.W. Brown Unit 5	47.00 %	47	28	—
Trimble County Unit 2	60.75 %	1,069	256	12
Trimble County Units 5-6	71.00 %	87	47	—
Trimble County Units 7-10	63.00 %	136	74	3
Cane Run Unit 7	78.00 %	486	109	6
E.W. Brown Solar Unit	61.00 %	16	7	—
Solar Share	56.00 %	4	1	—
Mercer Solar	63.00 %	13	—	23
Mill Creek Unit 5	69.00 %	1	—	486
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 Unit 5	69.00 %	—	—	164
Brown Wind	64.00 %	1	—	—
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 Unit 5	69.00 %	—	—	164
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	2027
Natural Gas Retail Supply	2026
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
2026	\$ 19	\$ 8	\$ 27
2027	24	10	34
2028	24	11	35
2029	25	11	36
2030	23	10	33
Thereafter	184	83	267
Total	\$ 299	\$ 133	\$ 432

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

	2025	2024	2023
LG&E	\$ 26	\$ 21	\$ 20
KU	11	9	9
Total	\$ 37	\$ 30	\$ 29

(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	2043

RIE's commitments under these long-term contracts subsequent to December 31, 2025 are summarized in the table below.

	Total	2026	2027-2028	2029-2030	Thereafter
Energy Purchase Obligations	\$ 939	\$ 268	\$ 199	\$ 126	\$ 346

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, 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, placed into service in 2016;
- the Three-State Procurement, involving six clean energy long-term contracts pursuant to the Rhode Island Long-Term Contracting Standard (LTCS) of which approximately 36 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 407 MW and is 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 December 23, 2025, the RIPUC approved the RFP for soliciting renewable energy under LTCS. Under the approved schedule, the RFP will be released, and the solicitation will commence on May 13, 2026 with the deadline for the submission of bids proposals on August 12, 2026.

In addition to the LTCS, on December 19, 2025, RIE along with state agencies and utilities in Maine, Massachusetts, Connecticut and Vermont, released a multi-state RFP to identify competitive proposals for renewable energy and associated transmission infrastructure in Northern Maine under the Affordable Clean Energy Security Act (ACES), as amended in 2022. Bids are due at the end of February 2026 and the selection process will conclude in the third quarter of 2026.

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 February 21, 2025, the Division filed testimony confirming its initial testimony that \$12 million is the appropriate amount to be refunded to the energy efficiency program. On March 4, 2025, a Settlement Agreement between RIE, the Division, and the Rhode Island Attorney General was filed with the RIPUC requiring refunds of \$10 million. Of this amount, \$2 million has already been refunded through the energy efficiency mechanism with the remaining \$8 million to reduce the storm cost regulatory asset recorded on PPL's balance sheet. The settlement also included reimbursement of minor consulting fees and various other compliance actions. On March 5, 2025, the RIPUC approved the Settlement Agreement.

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, but KU cannot predict the outcome of this matter.

(PPL, LG&E and KU)

EPA Deregulatory Initiative

On March 12, 2025, the EPA announced a plan to reconsider 31 environmental rules including the Section 111 performance standards and emissions limits for greenhouse gases, the endangerment finding for greenhouse gases, the Good Neighbor Plan, the Mercury and Air Toxics Standards, revisions to the fine particulate matter standard, the ELGs, and the CCRs Rule. Supplementing previous Executive Orders directing various regulatory changes, on April 9, 2025, President Trump issued an Executive Order and Presidential Memorandum directing review of existing rules, repeal of unlawful rules, and initiation of a zero-based budgeting process by which certain rules would automatically expire unless extended. While the current Presidential administration may seek to implement some regulatory changes outside of the rulemaking process, changes to existing rules are generally expected to require formal rulemaking proceedings. Any final EPA actions repealing or revising current rules will likely result in legal challenges. PPL, LG&E, and KU are unable to predict future regulatory changes, if any, that may result from the EPA's deregulatory plan or the outcome of any associated legal challenges. PPL, LG&E, and KU are closely monitoring the ongoing EPA initiative and any related litigation for the impact to our business including planned capital expenditures to comply with the EPA rules.

Water/Waste

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 could potentially result in significant operational changes and additional controls for LG&E and KU plants, but in March 2025 the EPA announced its plan to reconsider the rule. 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. On December 31, 2025, the EPA issued a final rule extending the retirement exemption category application deadline an additional six years, from December 2025 to December 2031 and a five-year extension to the zero liquid discharge deadlines, from December 2029 to December 2034. The EPA announced that it will conduct a technology review of the zero liquid discharge technology in a future rulemaking.

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. In March 2025, the EPA announced its plan to update the rule. On July 22, 2025, the EPA published a proposed rule to extend the deadline for select CCR management units for the Facility Evaluation Report Part 1 and Part 2 by one year to February 2027 and February 2028, respectively. The proposed rule would also extend the groundwater monitoring deadline to August 8, 2030, with the initial groundwater monitoring report extended to January 31, 2031.

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. Associated costs are subject to rate recovery through the Companies' ECR adjustment clause.

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, 2025 and December 31, 2024, 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, 2025 and December 31, 2024, RIE had a recorded liability of \$98 million and \$98 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.

Electricity - Reliability Standards

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.

Gas - Security Directives *(PPL and LG&E)*

In May and July of 2021, the Department of Homeland Security's (DHS) Transportation Security Administration issued 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. Both security directives have been updated and extended multiple times. The Transportation Security Administration has determined that LG&E is within the scope of the directives, while RIE has not been notified of this distinction. The first directive, most recently updated and now effective through January 2027, requires notified owners/operators to report specified cybersecurity incidents 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 results and proposed mitigation to the DHS. The second security directive, updated and effective through May 2026, requires refinement of a Transportation Security Administration-approved Cybersecurity Implementation Plan (CIP) and the Cybersecurity Assessment Plan (CAP). The Transportation Security Administration has transitioned to a performance-based regulatory model, requiring operators to meet defined cybersecurity outcomes rather than implement prescriptive controls. Key requirements now include: maintaining a Transportation Security Administration-approved CIP; reporting significant cybersecurity incidents to the Cybersecurity and Infrastructure Security Agency (CISA) within 24 hours; completing annual CAPs with all CIP measures assessed on a three-year cycle; conducting annual testing of at least two Cybersecurity Incident Response Plan (CIRP) objectives; meeting new 2026 vetting requirements for non-U.S. citizen cybersecurity coordinators (who must participate in a trusted traveler program); and complying with clarified rules governing shared responsibilities when third parties support pipeline operations. LG&E does not believe these security directives or their updates have had, or are expected to have, a material impact on its operations or financial condition.

Other

Guarantees and Other Assurances

(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 securities and loan obligations of PPL Capital Funding.

(All Registrants)

The table below details guarantees provided as of December 31, 2025. "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 guarantee related to the payment obligations of Safari under certain sale/leaseback financing transactions and PPL's agreement to fund any increases in the fair value of those obligations, which PPL believes are reasonably possible of occurring. For reporting purposes, on a consolidated basis, the guarantees of PPL include the guarantees of its subsidiary Registrants.

	Exposure at December 31, 2025	Expiration Date
PPL		
Indemnifications related to certain tax liabilities related to the sale of the U.K. utility business	£ 50 (a)	2028
PPL guarantees related to certain sale/leaseback financing transactions related to the sale of Safari Holdings	\$ 71 (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)	2028
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. In June 2025, the indemnifications were novated to PPL Energy Holdings.		
(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.		
Separately, PPL has agreed to fund incremental payment obligations under the buy-outs resulting from increases in the fair market value of the projects from the initial fair market value determined at the time of PPL's sale of Safari Holdings to the time the buy-out options are exercised by Safari. As of December 31, 2025, PPL cannot reasonably estimate its payment obligations related to the remaining buy-out options.		
(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.		
(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 \$71 million at December 31, 2025, consisting of LG&E's share of \$49 million and KU's share of \$22 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 for non-wildfire liability losses and maximum aggregate coverage of \$181 million for wildfire liability losses. 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.

	2025	2024	2023
PPL Electric from PPL Services	\$ 261	\$ 227	\$ 222
LG&E from LKS	113	105	115
LG&E from PPL Services	135	66	42
KU from LKS	141	130	150
KU from PPL Services	131	65	48

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, 2025, CEP Reserves had \$143 million of borrowings outstanding. At December 31, 2024, CEP Reserves had \$222 million 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, 2025, LG&E's money pool unused capacity was \$750 million. At December 31, 2025 LG&E had no borrowings from KU and/or LKE. At December 31, 2024, LG&E's borrowings outstanding from KU and/or LKE were \$43 million.

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, 2025, KU's money pool unused capacity was \$614 million. At December 31, 2025 KU had borrowings outstanding of \$36 million from LG&E and/or LKE. At December 31, 2024, KU's borrowings outstanding from LG&E and/or LKE were \$73 million.

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. There was no intercompany receivable balance associated with these funds at December 31, 2025, as PPL Electric's allocation of excess funds was depleted. 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.

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:

	2025	2024	2023
Defined benefit plans - non-service credits (Note 10)	\$ 59	\$ 42	\$ 40
Interest income	20	33	32
AFUDC - equity component	81	47	30
Talen litigation (a)	—	(2)	(124)
Miscellaneous	(9)	(6)	(18)
Other Income (Expense) - net	\$ 151	\$ 114	\$ (40)

(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:

	2025	2024	2023
Defined benefit plans - non-service credits (Note 10)	\$ 14	\$ 17	\$ 20
Interest income	8	8	8
AFUDC - equity component	30	23	16
Miscellaneous	(4)	(3)	(5)
Other Income (Expense) - net	\$ 48	\$ 45	\$ 39

(LG&E)

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

	2025	2024	2023
Defined benefit plans - non-service credits (Note 10)	\$ 3	\$ 3	\$ —
AFUDC - equity component	16	8	3
Miscellaneous	5	1	—
Other Income (Expense) - net	\$ 24	\$ 12	\$ 3

(KU)

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

	2025	2024	2023
Defined benefit plans - non-service credits (Note 10)	\$ 7	\$ 8	\$ 6
AFUDC - equity component	21	9	3
Miscellaneous	1	(2)	(1)
Other Income (Expense) - net	\$ 29	\$ 15	\$ 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, 2025				December 31, 2024			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
PPL								
Assets								
Cash and cash equivalents	\$ 1,071	\$ 1,071	\$ —	\$ —	\$ 306	\$ 306	\$ —	\$ —
Restricted cash and cash equivalents (a)	15	15	—	—	33	33	—	—
Total Cash, Cash Equivalents and Restricted Cash (b)	1,086	1,086	—	—	339	339	—	—
Special use funds (a):								
Money market fund	1	1	—	—	1	1	—	—
Commingled debt fund measured at NAV (c)	5	—	—	—	10	—	—	—
Commingled equity fund measured at NAV (c)	5	—	—	—	8	—	—	—
Total special use funds	11	1	—	—	19	1	—	—
Price risk management assets (d):								
Gas contracts	6	—	2	4	9	—	4	5
Total assets	\$ 1,103	\$ 1,087	\$ 2	\$ 4	\$ 367	\$ 340	\$ 4	\$ 5
Liabilities								
Price risk management liabilities (d):								
Interest rate derivatives	\$ 5	\$ —	\$ 5	\$ —	\$ 3	\$ —	\$ 3	\$ —
Gas contracts	10	—	6	4	13	—	10	3
Total price risk management liabilities	\$ 15	\$ —	\$ 11	\$ 4	\$ 16	\$ —	\$ 13	\$ 3
PPL Electric								
Assets								
Cash and cash equivalents	\$ 30	\$ 30	\$ —	\$ —	\$ 24	\$ 24	\$ —	\$ —
Total assets	\$ 30	\$ 30	\$ —	\$ —	\$ 24	\$ 24	\$ —	\$ —
LG&E								
Assets								
Cash and cash equivalents	\$ 162	\$ 162	\$ —	\$ —	\$ 8	\$ 8	\$ —	\$ —
Restricted cash and cash equivalents (a)	7	7	—	—	16	16	—	—
Total Cash, Cash Equivalents and Restricted Cash (b)	169	169	—	—	24	24	—	—
Total assets	\$ 169	\$ 169	\$ —	\$ —	\$ 24	\$ 24	\$ —	\$ —
Liabilities								
Price risk management liabilities (c):								
Interest rate derivatives	\$ 5	\$ —	\$ 5	\$ —	\$ 3	\$ —	\$ 3	\$ —
Total price risk management liabilities	\$ 5	\$ —	\$ 5	\$ —	\$ 3	\$ —	\$ 3	\$ —
KU								
Assets								
Cash and cash equivalents	\$ 10	\$ 10	\$ —	\$ —	\$ 13	\$ 13	\$ —	\$ —
Restricted cash and cash equivalents (a)	7	7	—	—	16	16	—	—
Total Cash, Cash Equivalents and Restricted Cash (b)	17	17	—	—	29	29	—	—
Total assets	\$ 17	\$ 17	\$ —	\$ —	\$ 29	\$ 29	\$ —	\$ —

- (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.
- (e) Current portion is included in "Other current 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
2025	
Balance at beginning of period	\$ 2
Total unrealized gains (losses) recognized as Regulatory Assets/Regulatory Liabilities	(2)
Balance at end of period	\$ —

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 Derivatives (PPL, LG&E and KU)

To manage interest rate risk, PPL, LG&E and KU use interest rate derivatives such as treasury locks, forward-starting swaps, floating-to-fixed swaps and fixed-to-floating swaps. An income approach is used to measure the fair value of these derivatives, 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 observations. 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 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, 2025		December 31, 2024	
	Carrying Amount (a)	Fair Value	Carrying Amount (a)	Fair Value
PPL	\$ 18,894	\$ 18,488	\$ 16,503	\$ 15,562
PPL Electric	5,707	5,473	5,214	4,862
LG&E	2,865	2,784	2,471	2,295
KU	3,510	3,304	3,066	2,750

(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

(All Registrants)

Risk Management Objectives

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 hedging instruments to limit exposure to fluctuations 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 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 mainly 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, if 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 obligation to return or post cash collateral under master netting arrangements at December 31, 2025 and 2024.

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 derivatives that qualify as cash flow hedges may be entered into to hedge floating interest rate risk associated with both existing and anticipated debt issuances. As of December 31, 2025, PPL held an aggregate notional value in interest rate derivatives of \$20 million that mature on June 15, 2026.

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 2025, 2024 and 2023, PPL had no cash flow hedges reclassified into earnings associated with discontinued cash flow hedges.

At December 31, 2025, 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, 2025, 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, 2025. At December 31, 2025, RIE held contracts with notional volumes of 48 Bcf that range in maturity from 2026 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, 2025 and 2024.

See Note 1 for additional information on accounting policies related to derivative instruments.

(PPL)

The following table presents the fair value and location of derivatives not designated as hedging instruments recorded on the Balance Sheets:

	December 31, 2025		December 31, 2024	
	Assets	Liabilities	Assets	Liabilities
Current:				
Price Risk Management				
Assets/Liabilities (a):				
Interest rate derivatives (b)	\$ —	\$ 1	\$ —	\$ —
Gas contracts	6	5	7	10
Total current	6	6	7	10
Noncurrent:				
Price Risk Management				
Assets/Liabilities (a):				
Interest rate derivatives (b)	—	4	—	3
Gas contracts	—	5	2	3
Total noncurrent	—	9	2	6
Total derivatives	\$ 6	\$ 15	\$ 9	\$ 16

(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	
2025				
Cash Flow Hedges:				
Interest rate derivatives	\$ 2	Interest Expense	\$ (3)	
Total	\$ 2		\$ (3)	
2024				
Cash Flow Hedges:				
Interest rate derivatives	\$ —	Interest Expense	\$ (3)	
Total	\$ —		\$ (3)	
2023				
Cash Flow Hedges:				
Interest rate derivatives	\$ —	Interest Expense	\$ (3)	
Total	\$ —		\$ (3)	
Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivative	2025	2024	2023
Gas contracts	Energy Purchases	\$ (9)	\$ (40)	\$ (19)
	Other income (expense) - net	(1)	—	(1)
	Total	\$ (10)	\$ (40)	\$ (20)

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized as Regulatory Liabilities/Assets	2025	2024	2023
Gas contracts	Regulatory assets - current	\$ 3	\$ 48	\$ 9
	Regulatory assets - noncurrent	(2)	7	(8)
Interest rate derivatives	Regulatory assets - noncurrent	—	4	—
	Total	\$ 1	\$ 59	\$ 1

The following table presents the effect of cash flow hedge activity on the Statement of Income for the year ended December 31, 2025:

	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	\$ 808
The effects of cash flow hedges:	
Gain (Loss) on cash flow hedging relationships:	
Interest rate derivatives:	
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, 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 derivatives:	
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 derivatives:	
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, 2025		December 31, 2024	
	Assets	Liabilities	Assets	Liabilities
Current:				
Price Risk Management				
Assets/Liabilities:				
Interest rate derivatives (a)	\$ —	\$ 1	\$ —	\$ —
Total current	—	1	—	—
Noncurrent:				
Price Risk Management				
Assets/Liabilities:				
Interest rate derivatives	\$ —	\$ 4	\$ —	\$ 3
Total noncurrent	—	4	—	3
Total derivatives	\$ —	\$ 5	\$ —	\$ 3

(a) Current portion is included in "Other current liabilities" on the Balance Sheets.

The following table presents 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)	2025	2024	2023
Interest rate derivatives	Regulatory assets - noncurrent	\$ (2)	\$ 4	\$ —

(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		Cash Collateral Received	Net	Eligible for Offset		Cash Collateral Pledged	Net
	Gross	Derivative Instruments			Gross	Derivative Instruments		
<u>December 31, 2025</u>								
<u>Derivatives</u>								
PPL	\$ 6	\$ 3	\$ —	\$ 3	\$ 10	\$ 3	\$ —	\$ 7
LG&E	—	—	—	—	5	—	—	5
<u>December 31, 2024</u>								
<u>Derivatives</u>								
PPL	\$ 9	\$ 5	\$ —	\$ 4	\$ 16	\$ 5	\$ —	\$ 11
LG&E	—	—	—	—	3	—	—	3

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, 2025, derivative contracts in a net liability position that contain credit risk-related contingent features was \$5 million. The aggregate fair value of additional collateral requirements in the event of a credit downgrade below investment grade was \$5 million.

17. Goodwill and Other Intangible Assets

Goodwill

(PPL)

Goodwill at PPL totaled \$2,247 million at December 31, 2025 and 2024, consisting of \$662 million for the Kentucky Regulated segment, \$725 million for the Rhode Island Regulated segment and \$860 million for Corporate and Other. There were no accumulated impairment losses related to goodwill.

Other Intangible Assets

(PPL)

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2025		December 31, 2024	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Contracts (a)	\$ 125	\$ 124	\$ 125	\$ 116
Renewable Energy Credits	24	—	20	—
Land rights and easements	445	139	432	147
Licenses and other	2	—	2	—
Total subject to amortization	596	263	579	263
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	\$ 614	\$ 263	\$ 597	\$ 263

(a) Gross carrying amount 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:

	2025	2024	2023
Intangible assets with no regulatory offset	\$ 5	\$ 5	\$ 5
Intangible assets with regulatory offset	8	8	9
Total	\$ 13	\$ 13	\$ 14

Amortization expense for each of the next five years is estimated to be:

	2026	2027	2028	2029	2030
Intangible assets with no regulatory offset	\$ 5	\$ 5	\$ 5	\$ 5	\$ 5
Intangible assets with regulatory offset	1	—	—	—	—
Total	\$ 6	\$ 5	\$ 5	\$ 5	\$ 5

(PPL Electric)

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2025		December 31, 2024	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Land rights and easements	\$ 408	\$ 145	\$ 396	\$ 141
Licenses and other	2	1	2	1
Total subject to amortization	410	146	398	142
Not subject to amortization due to indefinite life:				
Land rights and easements	18	—	18	—
Total	\$ 428	\$ 146	\$ 416	\$ 142

Intangible assets are shown as "Intangibles" on the Balance Sheets.

Amortization expense was as follows:

	2025	2024	2023
Intangible assets with no regulatory offset	\$ 4	\$ 4	\$ 4

Amortization expense for each of the next five years is estimated to be:

	2026	2027	2028	2029	2030
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, 2025		December 31, 2024	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Land rights and easements (a)	\$ 8	\$ (2)	\$ 7	\$ 2
OVEC power purchase agreement (b)	86	85	86	79
Total subject to amortization	\$ 94	\$ 83	\$ 93	\$ 81

(a) December 31, 2025 accumulated amortization includes salvage proceeds related to a land sale in excess of the related accumulated amortization.

(b) 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:

	2025	2024	2023
Intangible assets with regulatory offset	\$ 6	\$ 6	\$ 6

Amortization expense for each of the next five years is immaterial.

(KU)

The gross carrying amount and the accumulated amortization of other intangible assets were:

	December 31, 2025		December 31, 2024	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:				
Land rights and easements (a)	\$ 30	\$ (3)	\$ 29	\$ 4
OVEC power purchase agreement (b)	39	38	39	36
Total subject to amortization	\$ 69	\$ 35	\$ 68	\$ 40

- (a) December 31, 2025 accumulated amortization includes salvage proceeds related to a land sale in excess of the related accumulated amortization.
(b) 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:

	2025	2024	2023
Intangible assets with regulatory offset	\$ 2	\$ 2	\$ 3

Amortization expense for each of the next five years is estimated to be immaterial.

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	
	2025	2024	2025	2024	2025	2024
ARO at beginning of period	\$ 157	\$ 158	\$ 84	\$ 85	\$ 64	\$ 66
Accretion	8	8	4	4	4	4
Obligations incurred	—	9	—	3	—	6
Changes in estimated timing or cost	2	4	—	3	2	1
Obligations settled	(26)	(24)	(13)	(11)	(13)	(13)
Other	(1)	2	—	—	—	—
ARO at end of period	\$ 140	\$ 157	\$ 75	\$ 84	\$ 57	\$ 64

19. Accumulated Other Comprehensive Income (Loss)

(PPL)

The after-tax changes in AOCI by component for the years ended December 31 were as follows:

	Unrealized gains (losses) on qualifying derivatives	Equity investees' AOCI	Defined benefit plans		Total
			Prior service costs	Actuarial gain (loss)	
PPL					
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)
Amounts arising during the year	1	(1)	—	(20)	(20)
Reclassifications from AOCI	2	—	1	(1)	2
Net OCI during the year	3	(1)	1	(21)	(18)
December 31, 2025	\$ 12	\$ 3	\$ (2)	\$ (215)	\$ (202)

The following table presents PPL's gains (losses) and related income taxes for reclassifications from AOCI for the years ended December 31, 2025, 2024 and 2023. 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.

Details about AOCI	PPL			Affected Line Item on the Statements of Income
	2025	2024	2023	
Qualifying derivatives				
Interest rate derivatives	\$ (3)	\$ (3)	\$ (3)	Interest Expense
Total Pre-tax	(3)	(3)	(3)	
Income Taxes	1	—	—	
Total After-tax	(2)	(3)	(3)	
Defined benefit plans				
Prior service costs	(1)	(1)	(2)	
Net actuarial loss	2	4	3	
Total Pre-tax	1	3	1	
Income Taxes	(1)	—	1	
Total After-tax	—	3	2	
Total reclassifications during the year	\$ (2)	\$ —	\$ (1)	

20. New Accounting Guidance Pending Adoption

(All Registrants)

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 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.

Adoption of this guidance will result in additional disclosures. The Registrants plan to adopt the standard retrospectively effective for the year ending December 31, 2027.

Accounting for Internal-Use Software

In September 2025, the FASB issued guidance to clarify and modernize the accounting for costs related to internal-use software. This includes 1) eliminating the traditional stage-based model and requiring entities to start capitalizing software costs when (a) management has authorized/committed to funding the software project and (b) it is probable that the project will be completed and the software will be used to perform the function intended ("probable-to-complete recognition threshold"), 2) requiring entities to consider whether there is significant uncertainty associated with the development activities of the software when evaluating the probable-to-complete recognition threshold, and 3) clarifying disclosure requirements.

This guidance can be applied on either a prospective, modified, or retrospective basis and will be effective for annual periods beginning after December 15, 2027 and interim reporting periods within those annual reporting periods. 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:

	LG&E	
	December 31, 2025	December 31, 2024
Cash paid (received) during the period for:		
Income taxes	\$ 81	\$ 73
Interest	103	101
Significant noncash transactions:		
Accrued expenditures for property, plant, and equipment	142	64

22. Subsequent Events

Rate Case Proceedings

On March 11, 2026, LG&E and KU filed with the KPSC a Joint Petition for Reconsideration of the February 16, 2026 Orders ("The Petition") issued in connection with the 2025 LG&E and KU base rate proceedings. The Petition highlights several items for reconsideration within the orders including the rejection and/or modification of items expressly agreed to with intervening parties in the October 2025 stipulation and recommendation agreement. The Petition also notes LG&E's and KU's withdrawal from the stipulation and recommendation agreement, given the substantial modification within the KPSC's orders. The KPSC must grant or deny the Petition within twenty days after it is filed. LG&E and KU cannot predict the outcome of these proceedings.

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. Narragansett Electric is sometimes referred to as Rhode Island Energy or RIE.

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 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 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 Stock Purchase Agreement 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 - 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. PPL WPD Limited was dissolved June 17, 2025.

RIE - Rhode Island Energy, the name under which Narragansett Electric provides gas and electric services to customers in Rhode Island.

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.

2024 Form 10-K - Annual Report filed with the SEC on Form 10-K for the year ended December 31, 2024.

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).

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.

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

CLC - Corporate Leadership Council - executive management committee that is comprised of the President and Chief Executive Officer, Chief Technology and Innovation Officer, Chief Financial Officer, Chief Human Resources Officer, Chief Legal Officer, Chief Operating Officer-Utilities, Executive Vice President of Engineering, Construction and Generation.

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.

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.
DER - Distributed Energy Resources.
DRIP - PPL Amended and Restated Dividend Reinvestment and Direct Stock Purchase 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.
FY - fiscal year.
GAAP - Generally Accepted Accounting Principles in the U.S.
GHG(s) - greenhouse gas(es).
GWh - gigawatt-hour, one million kilowatt hours.
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, net of tax, 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.
ISR - Infrastructure, safety and reliability.
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.
LRS - Last Resort Service, the role of RIE in providing default electricity supply within its delivery area to all customers who have not elected to receive their electric supply from a non-regulated power producer or any customer who, for any reason, has stopped receiving generation service from a non-regulated power producer.
Mcf - one thousand cubic feet, a unit of measure for natural gas.
MMBtu - one million British Thermal Units.
Moody's - Moody's Ratings, a division of Moody's Corporation, 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.
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 Piquette, 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.
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 shareholder return (TSR) as compared to companies in the PHLX Utility Sector Index; (ii) corporate return on equity (ROE); (iii) corporate earnings growth (EG); and (iv) corporate environmental, social and governance (ESG) metrics.
PHMSA - Pipeline and Hazardous Materials Safety Administration.
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 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 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.

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.

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.

ROE - Return on equity.

Safari - 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.

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.

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.

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.

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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)								297,195,694	297,195,694
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)								309,209,099	309,209,099
10	Balance of Account 219 at End of Current Quarter/Year									

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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)	8,601,821,444	6,611,207,783	1,722,275,036				268,338,625
4	Property Under Capital Leases	17,379,206	2,607,552					14,771,654
5	Plant Purchased or Sold							
6	Completed Construction not Classified	773,014,106	433,628,111	258,249,221				81,136,774
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	9,392,214,756	7,047,443,446	1,980,524,257				364,247,053
9	Leased to Others							
10	Held for Future Use	2,903,133	2,903,133					
11	Construction Work in Progress	701,160,536	555,271,730	58,143,920				87,744,886
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	10,096,278,425	7,605,618,309	2,038,668,177				451,991,939
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	3,273,910,792	2,631,071,864	513,612,703				129,226,225
15	Net Utility Plant (13 less 14)	6,822,367,633	4,974,546,445	1,525,055,474				322,765,714
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	3,271,007,104	2,631,071,864	510,709,015				129,226,225
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights	2,903,688		2,903,688				
21	Amortization of Other Utility Plant							
22	Total in Service (18 thru 21)	3,273,910,792	2,631,071,864	513,612,703				129,226,225
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)							
32	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	3,273,910,792	2,631,071,864	513,612,703				129,226,225

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: UtilityPlantInServicePropertyUnderCapitalLeases
Amounts represent operating leases recorded in accordance with ASC 842 - Leases. LG&E 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. LG&E 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.
(c) Concept: UtilityPlantInServicePropertyUnderCapitalLeases
Amounts represent operating leases recorded in accordance with ASC 842 - Leases. LG&E 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: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

- Report below the original cost of electric plant in service according to the prescribed accounts.
- 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.
- Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
- 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.
- Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
- 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.
- 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.
- 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.
- 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	2,240					2,240
3	(302) Franchise and Consents						
4	(303) Miscellaneous Intangible Plant	455,858				(455,858)	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	458,098				(455,858)	2,240
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	11,802,620					11,802,620
9	(311) Structures and Improvements	349,874,442	1,580,298	322,361			351,132,379
10	(312) Boiler Plant Equipment	2,594,044,195	94,056,167	12,570,381			2,675,529,981
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	228,031,084	3,149,156	718,144			230,462,096
13	(315) Accessory Electric Equipment	185,048,842	1,822,418	19,133			186,852,127
13.1	(315.1) Computer Hardware		126,383			44,384	170,767
13.2	(315.2) Computer Software					94,510	94,510
13.3	(315.3) Communication Equipment						
14	(316) Misc. Power Plant Equipment	27,239,142	1,487,813	107,769			28,619,186
15	(317) Asset Retirement Costs for Steam Production	46,317,706	472,848	17,758,861			29,031,693
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	3,442,358,031	102,695,083	31,496,649		138,894	3,513,695,359
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						
22.1	(324.1) Computer Hardware						
22.2	(324.2) Computer Software						
22.3	(324.3) Communication Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	6					6
28	(331) Structures and Improvements	23,498,021	18,316				23,516,337
29	(332) Reservoirs, Dams, and Waterways	16,808,091					16,808,091
30	(333) Water Wheels, Turbines, and Generators	114,766,366					114,766,366
31	(334) Accessory Electric Equipment	7,474,356					7,474,356
31.1	(334.1) Computer Hardware						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
42	(345) Accessory Electric Equipment	32,784,950	32,355			(601,010)	32,216,295
42.1	(345.1) Computer Hardware						
42.2	(345.2) Computer Software						
42.3	(345.3) Communication Equipment						
43	(346) Misc. Power Plant Equipment	5,731,443	78,432			(316,459)	5,493,416
44	(347) Asset Retirement Costs for Other Production	115,361					115,361
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	433,025,429	2,549,215	758,932		(13,292,449)	421,523,263
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32, 35.47, and 45)	4,039,011,145	107,759,281	32,260,925		5,459,809	4,119,969,310
47	3. Transmission Plant						
48	(350) Land and Land Rights	11,239,819					11,239,819
48.2	(351.1) Computer Hardware		343,188	254,155		521,060	610,093
48.3	(351.2) Computer Software		288,899	239,772		2,811,121	2,860,248
48.4	(351.3) Communication Equipment		35,820			110,920	146,740
49	(352) Structures and Improvements	19,499,359	2,199,818	46,675			21,652,502
50	(353) Station Equipment	286,681,234	8,668,372	1,082,474			294,267,132
51	(354) Towers and Fixtures	50,412,522	1,142,948				51,555,470
52	(355) Poles and Fixtures	160,580,707	14,533,709	8,340			175,106,076
53	(356) Overhead Conductors and Devices	81,704,139	15,905,495	89,184			97,520,450
54	(357) Underground Conduit	1,941,042					1,941,042
55	(358) Underground Conductors and Devices	8,506,306	3,373				8,509,679
56	(359) Roads and Trails						
57	(359.1) Asset Retirement Costs for Transmission Plant	545,280					545,280
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	621,110,408	43,121,622	1,720,600		3,443,101	665,954,531
59	4. Distribution Plant						
60	(360) Land and Land Rights	4,109,979					4,109,979
61	(361) Structures and Improvements	15,252,827	254,412	87,912			15,419,327
62	(362) Station Equipment	248,157,486	6,436,363	863,153			253,730,696
63.1	(363.1) Computer Hardware		(1,922,911)			2,259,363	336,452
63.2	(363.2) Computer Software		(1,664,643)	44,653		5,347,566	3,638,270
63.3	(363.3) Communication Equipment		257,971			12,127,070	12,385,041
64	(364) Poles, Towers, and Fixtures	309,364,702	15,465,249	2,301,877			322,528,074
65	(365) Overhead Conductors and Devices	499,721,102	18,336,483	5,922,154			512,135,431
66	(366) Underground Conduit	98,401,981	4,381,654	15,015			102,768,620
67	(367) Underground Conductors and Devices	440,017,074	16,432,111	2,009,384			454,439,801
68	(368) Line Transformers	203,760,928	14,997,611	269,488			218,489,051
69	(369) Services	52,980,765	4,716,501	27,186			57,670,080
70	(370) Meters	22,318,567	79,528,943	9,914,540			91,932,970
71	(371) Installations on Customer Premises	301,985	806,211				1,108,196
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	168,148,589	12,174,895	980,668			179,342,816
74	(374) Asset Retirement Costs for Distribution Plant	987,082					987,082
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,063,523,067	170,200,850	22,436,030		19,733,999	2,231,021,886
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)						
84.1	6. ENERGY STORAGE PLANT						
84.2	(387.1) Land and Land Rights						
84.3	(387.2) Structures and Improvements						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
84.4	(387.3) Energy Storage Equipment						
84.6	(387.5) Collector System						
84.7	(387.6) Generator Step-up Transformers (GSU)						
84.8	(387.7) Inverters						
84.9	(387.8) Computer Hardware						
84.10	(387.9) Computer Software						
84.11	(387.10) Communication Equipment						
84.12	(387.11) Miscellaneous Energy Storage Equipment						
84.13	(387.12) Asset Retirement Costs for Energy Storage						
84.14	TOTAL Energy Storage Plant (Total lines 84.2 thru 84.13)						
85	7. General Plant						
86	(389) Land and Land Rights						
87	(390) Structures and Improvements						
88	(391) Office Furniture and Equipment						
89	(392) Transportation Equipment	9,827,156	(7,510)	59,372			9,760,274
90	(393) Stores Equipment						
91	(394) Tools, Shop and Garage Equipment	8,533,294	1,790,507	281,873			10,041,928
92	(395) Laboratory Equipment						
93	(396) Power Operated Equipment	5,454,988	983,149	73,054			6,365,083
94	(397.1) Computer Hardware						
94.1	(397.2) Computer Software		(8,305)	55,356		1,710,446	1,646,785
94.2	(397.3) Communication Equipment	6,807,502				(6,733,645)	73,857
95	(398) Miscellaneous Equipment						
96	SUBTOTAL (Enter Total of lines 86 thru 95)	30,622,940	2,757,841	469,655		(5,023,199)	27,887,927
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	30,622,940	2,757,841	469,655		(5,023,199)	27,887,927
100	TOTAL (Accounts 101 and 106)	6,754,725,658	323,839,594	56,887,210		23,157,852	7,044,835,894
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)	6,754,725,658	323,839,594	56,887,210		23,157,852	7,044,835,894

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Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: CommunicationEquipment

The \$6,807,502 beginning balance in Account 397.3, Communication Equipment, represents the ending balance of Account 397, Communication Equipment, as of December 31, 2024. As FERC Order No. 898 removed Account 397 from the 2025 FERC Form No. 1, the prior year balance is reported in Account 397.3.

(b) Concept: ProductionPlantTransfers	
<u>Intangible Plant</u>	<u>FERC 898 Transfers</u>
303 Miscellaneous Intangible Plant	(455,858)
Total	\$ (455,858)
<u>Steam Production Plant</u>	<u>FERC 898 Transfers</u>
315.2 Computer Software	94,510
Total	\$ 94,510
<u>Solar Production Plant</u>	<u>FERC 898 Transfers</u>
338.1 Land and Land Rights	386,266
338.2 Structures and Improvements	1,587,906
338.4 Solar Panels	7,635,305
338.5 Collector System	1,279,044
338.6 Generator Step-Up Transformers (GSU)	285,072
338.7 Inverters	1,112,693
338.8 Other Accessory Electrical Equipment	348,567
338.9 Computer Hardware	186,347
338.10 Computer Software	154,289
338.11 Communication Equipment	25,675
338.12 Miscellaneous Power Plant Equipment	237,917
Total	\$ 13,239,081
<u>Wind Production Plant</u>	<u>FERC 898 Transfers</u>
338.23 Wind Turbines	394,003
Total	\$ 394,003
<u>Other Production Plant</u>	<u>FERC 898 Transfers</u>
340 Land and Land Rights	(386,266)
341 Structures and Improvements	(1,567,669)
344 Generators	(10,421,045)
345 Accessory Electrical Equipment	(601,010)
346 Misc. Power Plant Equipment	(316,459)
Total	\$ (13,292,449)

(c) Concept: ElectricPlantInServiceAndCompletedConstructionNotClassifiedElectricTransfers	
<u>Transmission Plant</u>	<u>FERC 898 Transfers</u>
351.1 Computer Hardware	521,060
351.2 Computer Software	2,811,121
351.3 Communication Equipment	110,920
Total	\$ 3,443,101
<u>Distribution Plant</u>	<u>FERC 898 Transfers</u>
363.1 Computer Hardware	2,259,363
363.2 Computer Software	5,347,566
363.3 Communication Equipment	12,127,070
Total	\$ 19,733,999
<u>General Plant</u>	<u>FERC 898 Transfers</u>
397.2 Computer Software	1,710,446
397.3 Communication Equipment	(6,733,645)
Total	\$ (5,023,199)

(d) Concept: ElectricPlantInService

Excludes \$2,607,552 of Property Under Operating Leases recorded related to adoption and implementation of ASC 842 - Leases.

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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)
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47	TOTAL					

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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	US 42: Tract No. D152	01/31/2000	12/31/2032	253,321
3	Fegenbush Lane at the General Electric Plant	05/01/2012	12/31/2030	519,009
4	Tucker Station Distribution Substation - Blankenbaker Station Business Park, Tract 13	07/01/2012	12/31/2032	745,731
5	Land at Billtown Substation	08/01/2016	12/31/2031	871,644
6	Other Items Less Than \$250K			492,833
7				
21	Other Property:			
22	Site Development - Kentucky Substation, Tract D146	06/30/1992	12/31/2035	20,595
47	TOTAL			2,903,133

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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	TRIMBLE COUNTY UNIT 1 STACK LINER REPLACEMENT	12,805,290
3	MILL CREEK UNIT 3 SUPERHEAT INTERMEDIATE TUBES	4,062,208
4	MILL CREEK UNIT 3 WET FLUE GAS DESULFURIZATION RECYCLE HEADER REPLACEMENT	2,688,618
5	MILL CREEK D CONVEYOR STRUCTURE REPLACEMENT	2,457,964
6	TRIMBLE COUNTY COAL COMBUSTION RESIDUALS LANDFILL	2,392,062
7	MILL CREEK COAL HANDLING MOORING CELLS 1 AND 12 REFURBISH	1,784,572
8	TRIMBLE COUNTY UNIT 1 DISTRIBUTED CONTROLS SYSTEM UPGRADE	1,407,023
9	EFFLUENT LIMITATIONS GUIDELINES MILL CREEK ENVIRONMENTAL COST RECOVERY	1,379,344
10	MILL CREEK UNIT 3 COOLING TOWER CABLE	1,346,069
11	EFFLUENT LIMITATIONS GUIDELINES TRIMBLE COUNTY ENVIRONMENTAL COST RECOVERY	1,311,493
12	TRIMBLE COUNTY UNIT 1 SELECTIVE CATALYTIC REDUCTION SYSTEM CATALYST LAYER 2	1,261,560
13	MILL CREEK UNIT 3 WALLBLOWER WATERWALL PANELS	1,213,914
14	MILL CREEK UNIT 3 SELECTIVE CATALYTIC REDUCTION SYSTEM CATALYST LAYER 2	1,161,929
15	TRIMBLE COUNTY UNIT 1 COAL MILL GEARBOX	1,043,394
16	STEAM PRODUCTION MINOR	19,365,718
17	HYDRAULIC POWER MAJOR	
18	OHIO FALLS UNITS 9 & 10 INTAKE SLABS	2,213,856
19	HYDRAULIC POWER MINOR	90,565
20	SOLAR PRODUCTION MAJOR	
21	MERCER COUNTY SOLAR FIELD	12,559,701
22	SOLAR PRODUCTION MINOR	1,011,963
23	ENERGY STORAGE MAJOR	
24	125MW/500MW OF LITHIUM BATTERY STORAGE AT BROWN GENERATING STATION	90,756,877
25	OTHER PRODUCTION MAJOR	
26	MILL CREEK UNIT 5 NATURAL GAS COMBINED CYCLE	218,935,827
27	MILL CREEK UNIT 6	31,027,183
28	BROWN UNIT 12	26,689,301
29	CANE RUN UNIT 7 WAREHOUSE	1,204,322
30	OTHER PRODUCTION MINOR	3,496,780
31	TRANSMISSION MAJOR	
32	PADDYS RUN SUBSTATION RENOVATION	13,598,923
33	PROACTIVE RELAY REPLACEMENT TIP TOP PROACTIVE BREAKER REPLACEMENT	6,213,811
34	CAMPGROUND ROAD SUBSTATION	4,775,734
35	GENERATION EXPANSION PLAN MILL CREEK UNIT 5 NATURAL GAS COMBINED CYCLE NETWORK INTERCONNECTION	3,746,602
36	PROACTIVE TRANSFORMER REPLACEMENT MIDDLETOWN 345	2,841,111
37	PROACTIVE BREAKER REPLACEMENT ETHEL 3	2,609,117
38	PROACTIVE BREAKER REPLACEMENT BRECKENRIDGE PROACTIVE RELAY REPLACEMENT	1,525,811
39	PROACITVE RELAY REPLACEMENT BEARGRASS PROACTIVE BREAKER REPLACEMENT	1,499,174
40	TRANSMISSION EXPANSION PLAN MIDDLETOWN BUCKNER	1,441,504
41	CRITICAL REPLACEMENT TRANSMISSION LINES	1,337,340
42	PROACTIVE RELAY REPLACEMENT NORTHSIDE	1,208,322
43	INSITE KENTUCKY TRANSMISSION	1,162,444
44	TRANSMISSION MINOR	15,211,560
45	DISTRIBUTION MAJOR	
46	DISTRIBUTION SYSTEM HARDENING AND RESILIENCY PROGRAM SEGMENTATION	6,912,441
47	MAJOR STORMS CAPITAL	4,326,221

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
48	POLE INSPECTION TREATMENT PROGRAM LOUISVILLE	2,967,312
49	DISTRIBUTION SYSTEM HARDENING AND RESILIENCY PROGRAM	2,606,634
50	BRANDENBURG TRANSFORMER	2,284,208
51	RELAY REPLACEMENT	2,212,863
52	TRANSFORMER CONTROLS MODERNIZATION	2,070,510
53	TRANSFORMER 138 13.09 KILOVOLT 28 MEGAVOLT AMPERES	1,530,603
54	NEW BUSINESS TRANSFORMERS	1,466,289
55	GOSS 4 KILOVOLT CONVERSION	1,456,144
56	CRESTWOOD 1222 CRESTWOOD 1228 CIRCUIT TIE	1,406,492
57	ENGLISH STATION PUBLIC WORKS	1,294,061
58	FEGENBUSH SMYRNA 1255 AND WORTHINGTON 1155	1,103,425
59	DISTRIBUTION MINOR	22,434,487
60	GENERAL PLANT MINOR	3,425
61	RESEARCH, DEVELOPMENT, AND DEMONSTRATING MINOR	357,629
43	Total	555,271,730
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Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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	2,452,545,733	2,452,545,733		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	231,241,497	231,241,497		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	272,358	272,358		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):				
9.2	Fuel Stock	620,170	620,170		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	232,134,025	232,134,025		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(43,709,255)	(39,123,005)	(4,586,250)	
13	Cost of Removal	(20,523,267)	(20,824,955)	301,688	
14	Salvage (Credit)	5,625,088	1,340,526	4,284,562	
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(58,607,434)	(58,607,434)		
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)	5,304,050	5,304,050		
17.2	Customer payments related to construction projects	971,572	971,572		
17.3	Transfers to Depreciation Reserve Related to FERC 898	8,319,237	8,319,237		
17.4	Transfer Undepreciated Legacy Meters to Regulatory Asset	8,168,886	8,168,886		
18	Book Cost or Asset Retirement Costs Retired	(17,764,205)	(17,764,205)		
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,631,071,864	2,631,071,864		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	1,486,164,082	1,486,164,082		
21	Nuclear Production				
22	Hydraulic Production-Conventional	38,658,196	38,658,196		
23	Hydraulic Production-Pumped Storage				
23.1	Solar Production	5,060,620	5,060,620		
23.2	Wind Production	36,166	36,166		
23.3	Other Renewable Production				
24	Other Production	214,868,443	214,868,443		
25	Transmission	221,976,539	221,976,539		
26	Distribution	653,072,147	653,072,147		
27	Regional Transmission and Market Operation				
27.1	Energy Storage				
28	General	11,235,671	11,235,671		
29	TOTAL (Enter Total of lines 20 thru 28)	2,631,071,864	2,631,071,864		

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

- Report below investments in Account 123.1, Investments in Subsidiary Companies.
- 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.
- Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
- 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.
- 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.
- Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
- 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).
- 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 - 700 shares - 11/18/52 - Capital Stock	11/18/1952		70,000			70,000	
3	OVEC Common Stock - 700 shares - 1/8/53 - Capital Stock	01/08/1953		70,000			70,000	
4	OVEC Common Stock - 700 shares - 2/25/53 - Capital Stock	02/25/1953		70,000			70,000	
5	OVEC Common Stock - 700 shares - 4/10/1953 - Capital Stock	04/10/1953		70,000			70,000	
6	OVEC Common Stock - 700 shares - 5/12/53 - Capital Stock	05/12/1953		70,000			70,000	
7	OVEC Common Stock - 1,400 shares - 7/27/53 - Capital Stock	07/27/1953		140,000			140,000	
8	OVEC Common Stock - 730 shares - 3/4/05 - Capital Stock	03/04/2005		104,286			104,286	
42	Total Cost of Account 123.1 \$ 594,286.00		Total	594,286			594,286	

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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)	64,356,398	58,414,190	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)	24,812,847	35,481,789	Electric, Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	28,406,454	24,102,339	Electric, Gas
8	Transmission Plant (Estimated)	1,364,430	1,113,749	Electric
9	Distribution Plant (Estimated)	7,863,846	7,271,823	Electric, Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
10.1	Energy Storage Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	62,447,577	67,969,700	
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)	1,121,787	710,862	Electric, Gas
17				
18				
19				
20	TOTAL Materials and Supplies	127,925,762	127,094,752	

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FOOTNOTE DATA

(a) Concept: StoresExpenseUndistributed		
Balance at Beginning of Year	\$	167,076
Total Debits		3,148,764
Total Credits		(2,194,053)
Balance at End of Year	\$	1,121,787
(b) Concept: StoresExpenseUndistributed		
Balance at Beginning of Year	\$	1,121,787
Total Debits		3,313,239
Total Credits		(3,724,164)
Balance at End of Year	\$	710,862

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Allowances and Environmental Credits (Accounts 158.1, 158.2, 158.3, and 158.4)

- Report below the details related to allowances and environmental credits. Additional information about the type of allowances/environmental credits required by other regulatory bodies can be disclosed within the footnote data.
- Report all acquisitions of allowances and environmental credits at cost.
- Report allowances and environmental credits 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.
- Report the allowances and environmental credits transactions by the period they are first eligible for use: the current year's allowances and environmental credits in columns (b)-(c), allowances and environmental credits for the three succeeding years in columns (d)-(i), starting with the following year, and allowances and environmental credits for the remaining succeeding years in columns (j)-(k).
- Report on Line 4 authoritative agency issued allowances. Report withheld portions Lines 36-40.
- Report on Line 5 allowances returned by an authoritative agency. Report on Line 39 the authoritative agency's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the authoritative agency's sale or auction of the withheld allowances.
- Report on Lines 8-14 the names of vendors/transferors of allowances and environmental credits acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
- Report on Lines 22 - 27 the name of purchasers/ transferees of allowances and environmental credits disposed of and identify associated companies.
- Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
- Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance and environmental credits sales.

Line No.	Allowances and Environmental Credits Inventory (Accounts 158.1, 158.3, and 158.4) (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	882,199	130	90,692		62,379		62,379		1,684,233		2,781,882	130
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	260,025										260,025	
5	Returned by authoritative agency												
6													
7													
8	Purchases/Transfers:												
9	KINGS POINT WIND	19,593										19,593	
10	Osborn Wind Energy	20,221										20,221	
11	NORTH FORK RIDGE WIND	37,013										37,013	
12	White Cloud Wind Project	9,299										9,299	
13	Rock Creek Wind Project	5,766										5,766	
14	IMEA/IMPA	(597)										(597)	
15	Total	91,295										91,295	
16													
17	Relinquished During Year:												
18	Charges to Account 509, 555.2, and 555.3	14,485	1									14,485	1
19	Other:												
20	Allowances Used												
20.1	Allowances Used	549										549	
21	Cost of Sales/Transfers:												
22	ACT Commodities - Transfers	223,544										223,544	
23	STX Commodities - Transfers	25,461										25,461	
24	Louisville Gas & Electric - REC retirements	102,912										102,912	
25													
26													
27													
28	Total	351,917										351,917	
29	Balance-End of Year	866,568	129	90,692		62,379		62,379		1,684,233		2,766,251	129
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains		357,525										
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	901		901		901		901		44,149		47,753	

Line No.	Allowances and Environmental Credits Inventory (Accounts 158.1, 158.3, and 158.4) (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)
37	Add: Withheld by authoritative agency												
38	Deduct: Returned by authoritative agency												
39	Cost of Sales	901								901		1,802	
40	Balance-End of Year			901		901		901		43,248		45,951	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)	901	9							901	8	1,802	17
45	Gains		9								8		17
46	Losses												
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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		Balance at End of Year (f)
				Account Charged (d)	Amount (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						
20	TOTAL					

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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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	Retirement Costs of LG&E's Mill Creek Unit 1	84,031,432	894,248	407	7,607,852	76,423,580
22	December 12, 2024 (03-2025 to 02-2035)					
23	Legacy Meters: Unrecovered Costs upon Deployment of AMI Program	8,168,886	8,168,886			8,168,886
24	August 12, 2021 (01-2026 to 12-2040)					
49	TOTAL	92,200,318	9,063,134		7,607,852	84,592,466

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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	Campground Rd	10,851	561.6	20,678	561.6
4	CAMPGRND Incrse			1,267	561.6
5	CR7 INCREASE			695	561.6
6	LKE Meridian 138kV (SIS)	4,527	561.6	8,674	561.6
7	LKE Meridian 345kV (SIS)	20,357	561.6	28,592	561.6
8	LKE CMPGRND Load (SIS)	481	561.6	635	561.6
9	LKE Reliable Partner	925	561.6	1,219	561.6
10	LKE MC2 DNR (SIS)	1,101	561.6	1,441	561.6
11	LKE Aphorio 120MW (SIS)	1,189	561.6	1,562	561.6
12	LKE Aphorio 17MW (SIS)	528	561.6	684	561.6
13	LKE MC5 Aux	487	561.6	630	561.6
14	Facilities Study				
15	LKE Meridian 138kV (FS)	26,515	561.6	26,652	561.6
16	LKE Meridian 345kV (FS)	11,843	561.6	11,952	561.6
17	LKE DNR CR7 Increase	9,886	561.6	1,781	561.6
18	LKE CMPGrnd Increase	5,723	561.6	5,723	561.6
19	LKE CMPGRND Load (FS)	25,699	561.6	25,750	561.6
20	LKE MC2 DNR (FS)	4,750	561.6		
21	LKE Aphorio 120MW (FS)	6,500	561.6		
22	LKE Reliable Partnrs	3,557	561.6		
23	LKE Aphorio 17MW (FS)	4,750	561.6		
20	Total	139,669		137,935	
21	Generation Studies				
22	System Impact Study				
23	Mill Creek 5 345kV			964	561.7
24	Cluster Study				
25	Trans Cluster Study	33,880	561.7	35,510	561.7
26	AFSS 2024 TCS	126,000	561.7	126,000	561.7
39	Total	159,880		162,474	
40	Grand Total	299,549		300,409	

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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		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	ASC 715 - Pension and Postretirement	180,683,526	(3,356,306)	926/107	8,852,628	168,474,592
2	ARO - Generation - Coal Combustion Residuals	75,612,108	1,595,243	407	4,204,434	73,002,917
3	Pension Gain/Loss Amortization - 15 Year	43,519,082	(2,056,287)			41,462,795
4	Forward Starting Swaps Losses	21,523,295		427	2,037,203	19,486,092
5	Interest Rate Swap (Mark To Market)	3,835,930	903,752			4,739,682
6	Plant Outage Normalization	7,199,647		510-514/549/551-554	2,453,166	4,746,481
7	Gas Supply Clause	2,559,187	31,087,765	480-482	23,986,165	9,660,787
8	Asset Retirement Obligation - Electric	7,991,866	1,910,987	230	697,703	9,205,150
9	Swap Termination - Bank of America	5,216,873		427	558,952	4,657,921
10	Gas Line Tracker	4,490,000	1,055,000	480-482	365,000	5,180,000
11	ASC 740 - Income Taxes	9,933,600	5,421,167	410/411/282/283	168,508	15,186,259
12	Ice Storm 2018	4,227,626		571/580/583/590/593-595/598	650,404	3,577,222
13	Swap Termination - Wachovia	4,014,622		930	388,721	3,625,901
14	Asset Retirement Obligation - Gas	9,834,958	4,616,836	230	3,177,973	11,273,821
15	DSM Cost Recovery	646,000	1,051,000	440-445	1,322,000	375,000
16	Summer Storm	1,067,321		593	246,305	821,016
17	Rate Case Expenses - Electric	88,731	997,539			1,086,270
18	Rate Case Expenses - Gas	40,713	328,282			368,995
19	AMI Capital - Electric	259,253	270,893			530,146
20	AMI Capital - Gas	257,229	166,771			424,000
21	AMI O&M - Electric	9,754,256	4,747,629			14,501,885
22	AMI O&M - Gas	3,856,271	1,756,363			5,612,634
23	AMI Capital - Common	609,131	220,939			830,070
24	2023 Wind Storm	8,360,948				8,360,948
25	Generation Capital	78,672	652,901			731,573
26	May 2024 Storms	4,364,268	29,876			4,394,144
27	September 2024 Storms	1,547,692	21,108			1,568,800
28	Fuel Adjustment Clause	599,000	7,239,000	440-445	4,455,000	3,383,000
29	2025 Winter Storm		2,304,894			2,304,894
30	May 2025 Storm		2,372,513			2,372,513
44	TOTAL	412,171,805	63,337,865		53,564,162	421,945,508

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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.

ASC 715 - Pension and Postretirement

Order/docket number:

KPSC 2025-00114

FERC AI07-1-000

Amortization Period : Ongoing

ARO - Generation - Coal Combustion Residuals

Order/docket number:

KPSC 2025-00114

Amortization Period: Amortization period for closed plants is from July 2016 through June 2026 and amortization period for open plants is from July 2016 through June 2041.

Pension Gain/Loss Amortization - 15 Year

Order/docket number:

KPSC 2025-00114

Amortization Period: Ongoing

Forward Starting Swaps Losses

Order/docket number:

KPSC 2025-00114

Amortization Period: September 2015 to October 2045

Interest Rate Swap (Mark to Market)

Order/docket number:

KPSC 2025-00114

Plant Outage Normalization

Order/docket number:

KPSC 2025-00114

Amortization Period: July 2021 to June 2029

Gas Supply Clause

Order/docket number:

KPSC 2025-00114

KPSC 2022-00083

Amortization Period: Ongoing

Asset Retirement Obligation - Electric

Order/docket number:

KPSC 2025-00114

FERC ER08-1588-000

Amortization Period: Ongoing

Swap Termination - Bank of America

Order/docket number:

KPSC 2025-00114

Amortization Period: July 2017 to May 2034

Gas Line Tracker

Order/docket number:

KPSC 2025-00114

KPSC 2022-00056

Amortization Period : Ongoing

ASC 740 - Income Taxes

Order/docket number:

KPSC 2025-00114

Amortization Period: Ongoing

Ice Storm 2018

Order/docket number:

KPSC 2025-00114

Amortization Period: July 2021 to June 2031

Swap Termination - Wachovia

Order/docket number:

KPSC 2025-00114

Amortization Period: August 2010 to April 2035

Asset Retirement Obligation - Gas

Order/docket number:

KPSC 2025-00114

FERC ER08-1588-000

Amortization Period : Ongoing

DSM Cost Recovery

Order/docket number:

KRS 278.285

Amortization Period : Ongoing

Summer Storm

Order/docket number:

KPSC 2025-00114

Amortization Period: May 2019 to April 2029

Rate Case Expenses - Electric

Order/docket number:

KPSC 2025-00114

Rate Case Expenses - Gas

Order/docket number:

KPSC 2025-00114

AMI Capital - Electric

Order/docket number:

KPSC 2025-00114

AMI Capital - Gas

Order/docket number:

KPSC 2025-00114

AMI O&M - Electric

Order/docket number:

KPSC 2025-00114

AMI O&M - Gas

Order/docket number:

KPSC 2025-00114

AMI Capital - Common

Order/docket number:

KPSC 2025-00114

2023 Wind Storm

Order/docket number:

KPSC 2023-00093

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

Fuel Adjustment Clause
Order/docket number:
807 KAR 5:506
Amortization Period : Ongoing

2025 Winter Storm
Order/docket number:
KPSC 2025-00025

May 2025 Storm
Order/docket number:
KPSC 2025-00196

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MISCELLANEOUS DEFERRED 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	71,402	30,838	142,182.3	71,401	30,839
2	Financing Expense	61,515	3,844,473	181,428	3,896,255	9,733
3	Unamortized Debt	1,689,650	924,388	930.2	628,247	1,985,791
4	Advanced Contract Payments	5,392,166	6,275,837	107	1,863,973	9,804,030
5	Cane Run 7 LTPC Asset	1,300,475	2,010,150			3,310,625
6	Brown 6 and 7 LTSA Asset	1,485,850	455,151			1,941,001
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	10,001,058				17,082,019

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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	Air Permit Fees	854,929	908,018
3	AMI O&M KPSC Reg Liability	404,814	1,011,365
4	Asset Retirement Obligation	5,524,654	5,689,934
5	Bad Debts Reserve	765,738	1,054,796
6	Coal Combustion Residual ARO	4,489,214	2,003,979
7	Environmental Cost Recovery	1,562,618	802,142
8	Excess Deferred Taxes	15,655,216	14,896,634
9	Interest Rate Swaps	6,169,168	6,063,389
10	Leases	3,828,291	4,361,442
11	Off-Systems Sales Tracker	38,923	417,165
12	Other Postretirement & Employment Benefits	10,286,887	10,073,351
13	Performance Incentive		1,565,554
14	Regulatory Tax Adjustment	80,431,736	76,767,518
15	State Tax Credit Carryforward	6,051,400	4,538,550
16	Valuation Allowances	(6,051,400)	(4,538,550)
17	Vacation Pay	1,075,695	1,095,716
18	Workers Compensation	283,823	118,571
7	Other	828,388	1,631,322
8	TOTAL Electric (Enter Total of lines 2 thru 7)	132,200,094	128,460,896
9	Gas		
10	AMI O&M KPSC Reg Liability	312,779	1,043,205
11	Asset Retirement Obligation	12,021,587	11,459,813
12	Capitalized Gas Inventory	1,307,051	1,049,062
13	Demand Side Management	1,574,148	1,721,148
14	Excess Deferred Taxes	1,991,290	1,960,505
15	Interest Rate Swaps	1,542,230	1,515,786
16	Other Postretirement & Employment Benefits	2,859,045	2,795,262
17	Regulatory Tax Adjustment	22,232,526	21,886,770
18	Vacation Pay	327,215	332,220
19	Workers Compensation	108,437	67,125
15	Other	328,597	900,005
16	TOTAL Gas (Enter Total of lines 10 thru 15)	44,604,905	44,730,901
17.1	Other Deductions	10,965	287,950
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	176,815,964	173,479,747

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Balance at Beginning of Year	\$	184,635,787
Less Debits to:		
Account 410.1		14,369,418
Account 410.2		66
Other Balance Sheet Accounts		6,035,855
Plus Credits to:		
Account 411.1		12,583,876
Account 411.2		1,640
Balance at End of Year	\$	176,815,964

(b) Concept: AccumulatedDeferredIncomeTaxes

Balance at Beginning of Year	\$	176,815,964
Less Debits to:		
Account 410.1		15,418,167
Account 410.2		2,203
Other Balance Sheet Accounts		4,009,974
Plus Credits to:		
Account 411.1		15,814,939
Account 411.2		279,188
Balance at End of Year	\$	173,479,747

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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	75,000,000			21,294,223	425,170,424				
6	Total	75,000,000			21,294,223	425,170,424				
7	Preferred Stock (Account 204)									
8	Preferred Stock, \$25 Par Value	1,720,000								
9	Preferred Stock, Without Par Value	6,750,000								
14	Total	8,470,000								

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 2026-03-19	Year/Period of Report End of: 2025/ Q4
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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	788,081,499
15.1	Capital Contributions	281,000,000
15.2	Return of Capital to Parent	(55,000,000)
16	Ending Balance Amount	1,014,081,499
17	Other Paid in Capital	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	1,014,081,499

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ 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	835,889	
22	TOTAL	835,889	

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224)

- 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.
- 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.
- 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.
- 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.
- 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.
- 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.
- 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.
- 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.
- 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	^(B) Pollution Control Bonds:												
3	Jefferson County 2001 Series A, due 09/01/2026, 0.900%	221	22,500,000		440,697			03/06/2002	09/01/2026	03/06/2002	09/01/2026	22,500,000	202,500
4	Trimble County 2001 Series A, due 09/01/2026, 0.625%	221	27,500,000		799,357			03/06/2002	09/01/2026	03/06/2002	09/01/2026	27,500,000	171,875
5	Jefferson County 2001 Series B, due 11/01/2027, 1.350%	221	35,000,000		753,491			03/22/2002	11/01/2027	03/22/2002	11/01/2027	35,000,000	472,500
6	Trimble County 2001 Series B, due 11/01/2027, 1.350%	221	35,000,000		753,530			03/22/2002	11/01/2027	03/22/2002	11/01/2027	35,000,000	472,500
7	Louisville Metro 2003 Series A, due 10/01/2033, 2.000%	221	128,000,000		6,791,072			11/20/2003	10/01/2033	11/20/2003	10/01/2033	128,000,000	2,560,000
8	Louisville Metro 2005 Series A, due 02/01/2035, 1.750%	221	40,000,000		1,771,967			04/13/2005	02/01/2035	04/13/2005	02/01/2035	40,000,000	700,000
9	Louisville Metro 2007 Series A, due 06/01/2033, Variable	221	31,000,000		1,518,920			04/26/2007	06/01/2033	04/26/2007	06/01/2033	31,000,000	863,347
10	Louisville Metro 2007 Series B, due 06/01/2033, Variable	221	35,200,000		1,691,978			04/26/2007	06/01/2033	04/26/2007	06/01/2033	35,200,000	944,105
11	Trimble County 2016 Series A, due 09/01/2044, 1.300%	221	125,000,000		1,536,442			09/15/2016	09/01/2044	09/15/2016	09/01/2044	125,000,000	1,625,000
12	Trimble County 2017 Series A, due 06/01/2033, 3.750%	221	60,000,000		699,660			06/01/2017	06/01/2033	06/01/2017	06/01/2033	60,000,000	2,250,000
13	Trimble County 2023 Series A, due 06/01/2054, 4.700%	221	65,000,000		729,158			12/06/2023	06/01/2054	12/06/2023	06/01/2054	65,000,000	3,055,000
14	^(B) Interest Rate Swaps:												965,395

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)
15	First Mortgage Bonds:												
16	2010 due 11/15/2040, 5.125%	221	285,000,000		3,570,026		3,100,600	11/16/2010	11/15/2040	11/16/2010	11/15/2040	285,000,000	14,606,250
17	2013 due 11/15/2043, 4.650%	221	250,000,000		2,742,758		1,800,000	11/14/2013	11/15/2043	11/14/2013	11/15/2043	250,000,000	10,191,296
18	2015 due 10/01/2025, 3.300%	221	300,000,000		2,374,181		129,000	09/28/2015	10/01/2025	09/28/2015	10/01/2025		8,476,147
19	2015 due 10/01/2045, 4.375%	221	250,000,000		2,569,890		207,500	09/28/2015	10/01/2045	09/28/2015	10/01/2045	250,000,000	11,923,556
20	2019 due 04/01/2049, 4.250%	221	400,000,000		4,266,089		472,000	04/01/2019	04/01/2049	04/01/2019	04/01/2049	400,000,000	17,000,000
21	2023 due 04/15/2033, 5.450%	221	400,000,000		3,483,529		912,000	03/20/2023	04/15/2033	03/20/2023	04/15/2033	400,000,000	21,800,000
22	2025 due 08/15/2055, 5.850%	221	700,000,000		7,530,782		203,000	08/13/2025	08/15/2055	08/13/2025	08/15/2055	700,000,000	15,697,500
23	Subtotal		3,189,200,000		44,023,527		6,824,100					2,889,200,000	113,976,971
24	Reacquired Bonds (Account 222)												
25													
26													
27													
28	Subtotal												
29	Advances from Associated Companies (Account 223)												
30													
31													
32													
33	Subtotal												
34	Other Long Term Debt (Account 224)												
35	Mid-Term Debt:												
36		224											
36	Subtotal												
33	TOTAL		3,189,200,000	50,847,627								2,889,200,000	113,976,971

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FOOTNOTE DATA

[\(a\)](#) Concept: ClassAndSeriesOfObligationCouponRateDescription

Pollution control series bonds are obligations of LG&E, issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates LG&E 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

As of December 31, 2025, the company had in effect two interest-rate swap agreements to hedge its exposure to tax exempt rates related to Pollution Control Bonds, Variable Rate Series. The Company's position under the swap agreements is to pay a fixed rate and receive a variable rate based on the Secured Overnight Financing Rate (SOFR). The specifics for each swap agreement related to notional amounts, maturity dates, payable and receivable positions are as follows:

Notional Amount	Maturity	Payable	Receivable
\$32,000,000	10/01/2033	Fixed at 3.657%	68% of 1 mo SOFR
\$32,000,000	10/01/2033	Fixed at 3.645%	68% of 1 mo SOFR

[\(c\)](#) Concept: ClassAndSeriesOfObligationCouponRateDescription

Proceeds from LG&E's First Mortgage Bond issued in 2010 were used to repay loans from a PPL subsidiary and for general corporate purposes. Proceeds from LG&E's First Mortgage Bond issued in 2013 were used for capital expenditures and general corporate purposes. Proceeds from LG&E's First Mortgage Bonds issued in 2015 were used to pay maturing debt, pay short-term debt, and general corporate purposes. The First Mortgage Bonds were issued at a discount. Proceeds from LG&E First Mortgage Bond issued in 2019 were used to repay the US Bank Term Loan Tranches 1 and 2 and pay short-term debt. The First Mortgage Bonds were issued at a discount. Proceeds from LG&E'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. Proceeds from KU's First Mortgage Bonds issued in 2025 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, 2025, all the Company's long-term debt is collateralized by a first mortgage lien on substantially all the assets of the Company in Kentucky.

[\(d\)](#) Concept: InterestExpenseOnLongTermDebtIssued

The amount reported of \$1,113,976,971 represents the balance in Account 427. The difference between the reported amount and the sum of Account 427 and 430 is due to the \$173,176 in Account 430, which is related to Louisville Gas and Electric's allocation of interest related to intercompany debt with an affiliate.

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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 filed, 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)	309,209,099
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Contribution in Aid of Construction	17,907,383
6	Demand Side Management	933,000
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal Income Taxes:Utility Operating Income	70,491,343
11	Federal Income Taxes: Other Income and Deductions	1,044,905
12	Provision for Deferred Income Taxes	(7,521,860)
13	481(a) Adjustment	2,085,728
14	AFUDC - DEBT WACC	1,269,330
15	Amortization of Regulatory Assets/Liability Associated with Terminated Swaps	603,499
16	Amortization of Storm Regulatory Assets	896,709
17	Bad Debts Reserve	1,466,520
18	Cancellation of Debt (Sec. 1502)	1,327,014
19	Capitalized Interest	26,072,693
20	Current State Income Tax	535,809
21	Customer Advances for Construction	2,363,764
22	Loss on Reacquired Debt Amortization	1,063,346
23	Nondeductible Expenses	1,823,433
24	Off-System Sales Tracker - Reg Liability	1,516,000
25	Performance Incentive	9,332,325
26	Plant Outage Normalization - Reg Asset	2,453,166
27	RAR Tracker - Reg Asset	6,713,604
28	R & D Costs - Section 174	3,183,278
29	Swap Termination	947,672
30	Other	1,474,353
14	Income Recorded on Books Not Included in Return	
15	Amortization of Investment Tax Credit	906,128
16	AFUDC Flow Through	13,525,202
17	AFUDC Debt	7,609,857
18	Environmental Cost Recovery	3,048,000
19	FAC Under Recovery KY - Reg Asset	2,784,000
20	Gas Line Tracker	690,000
21	Purchased Gas Adjustment	7,101,600
19	Deductions on Return Not Charged Against Book Income	
20	Tax over Book Depreciation, Net and Repairs	25,584,544
21	2025 Storm Damages	4,677,407
22	AFUDC - EQUITY - WACC	2,585,326
23	Capitalized Gas Inventory	1,040,160
24	Coal Combustion Residual ARO	3,071,306
25	Cost of Removal	35,933,757
26	Leases ASC 842	631,503

Line No.	Particulars (Details) (a)	Amount (b)
27	Pensions - Regulatory Asset	2,366,525
28	Post Retirement Write-off	939,747
29	Regulatory Expenses	1,325,819
30	Workers Compensation	827,913
31	Other	569,681
27	Federal Tax Net Income	341,973,638
28	Show Computation of Tax:	
29	21 % Rounded	71,814,464
30	Less: Tax Credits and Adjustments to Prior Years' Taxes to Accrual	(278,216)
31	Total	71,536,248
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Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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 (Included 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)
1	Income	Income Tax	Federal		2,286,388	0	71,540,760	66,936,774		6,890,374		55,833,151		
2					0	0				0				
3	Subtotal Federal Tax				2,286,388	0	71,540,760	66,936,774		6,890,374		55,833,151		
4	Income	Income Tax	Kentucky		946,245	0	14,285,657	13,944,126		1,287,776		11,262,141		
5	Public Service Commission	Other License And Fees Tax	Kentucky		0	1,266,517	2,550,298	2,567,562		0	1,283,781	1,944,954		
6	Subtotal State Tax				946,245	1,266,517	16,835,955	16,511,688		1,287,776	1,283,781	13,207,095		
7	Kentucky and Indiana	Property Tax	Kentucky and Indiana		34,758,366	0	51,212,159	35,574,087		50,396,438		36,594,589		
8	Subtotal Property Tax				34,758,366	0	51,212,159	35,574,087		50,396,438		36,594,589		
9	Federal and Kentucky Unemployment Insurance	Unemployment Tax	Federal and Kentucky		27,809	0	71,018	75,846		22,981		50,679		
10	Subtotal Unemployment Tax				27,809	0	71,018	75,846		22,981		50,679		
11	Kentucky Use Tax	Sales And Use Tax	Kentucky		625,783	0	7,707,425	7,428,258		904,950				
12	Indiana Use Tax	Sales And Use Tax	Indiana		1,495	0	48,403	49,898		0				
13	Subtotal Sales And Use Tax				627,278	0	7,755,828	7,478,156		904,950				
14	Miscellaneous	Miscellaneous Other Tax	Federal and Kentucky		0	0				0		33,222		
15	Subtotal Miscellaneous Other Tax				0	0				0		33,222		
16	FICA	Payroll Tax	Federal		935,587	0	9,072,577	9,017,100		991,064		6,220,190		
17	Subtotal Payroll Tax				935,587	0	9,072,577	9,017,100		991,064		6,220,190		
40	TOTAL				39,581,673	1,266,517	156,488,297	135,593,651		60,493,583	1,283,781	111,938,926		

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: DescriptionOfTaxesAccruedPrepaidAndCharged

Segregation of Other	Other (o)	Gas Acct. 408.1-409.1	Page 117 Other Inc & Deductions 408-2-409.2	Other Accounts
Income	\$ 15,707,609	\$ 14,658,192	\$ 1,044,905	\$ 4,513
FICA	2,852,387	2,600,531	—	251,856
Total Federal Tax	18,559,996	17,258,723	1,044,905	256,369
Income	3,023,516	2,831,478	192,038	—
Public Service Commission	605,344	605,344	—	—
Total State Tax	3,628,860	3,436,822	192,038	—
	—			
Kentucky and Indiana	14,617,570	11,880,789	4,116	2,732,665
Total Property Tax	14,617,570	11,880,789	4,116	2,732,665
Federal and Kentucky Unemployment Insurance	20,339	19,557	—	782
Total Unemployment Tax	20,339	19,557	—	782
Kentucky Use Tax	7,707,425	—	—	7,707,425
Indiana Use Tax	48,403	—	—	48,403
Total Sales and Use Tax	7,755,828	—	—	7,755,828
Miscellaneous	(33,222)	12,287	—	(45,508)
Total Miscellaneous Tax	(33,222)	12,287	—	(45,508)
TOTAL	\$ 44,549,371	\$ 32,608,178	\$ 1,241,059	\$ 10,700,136

Reconciliation to page 114-115, Line 14-16:

Federal Income:		Other:	
Electric	\$ 55,833,151	Electric Total	\$ 111,938,926
Gas	14,658,192	Gas Total	32,608,178
Total	\$ 70,491,343 114-15	Less Federal Income	(70,491,343)
		Less State Income	(14,093,619)
		Total	\$ 59,962,142 114-14
State Income:			
Electric	\$ 11,262,141		
Gas	2,831,478		
Total	\$ 14,093,619 114-16		

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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%	17,326,063			411.4	422,100		16,903,963	58 years	
7	Various	12,395,396	411.4	392,856	411.4	484,028		12,304,224	25 and 43 years	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	29,721,459		392,856		906,128		29,208,187		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										
11	Gas Utility									
12	TOTAL									
47	OTHER TOTAL									
48	GRAND TOTAL	29,721,459		392,856		906,128		29,208,187		

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Uncertain Tax Position	532,935	409.1	26,207	21,695	528,423
2	MCI Amortization (Amortization Period: 03/2009 - 02/2028)	116,521	454	36,796		79,725
3	Def Economic Dev-Utility Settle	2,000,000	232	106,000	1,006,000	2,900,000
4	Other Deferred Credits	173,232	431, 926	25,584	10,155,131	10,302,779
47	TOTAL	2,822,688		194,587	11,182,826	13,810,927

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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)
			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)	Debits		Credits		
							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: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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				ADJUSTMENTS				Balance at End of Year (k)
			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)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	660,347,942	82,284,699	93,219,957			182/254	1,698,732	182/254	18,326,821	666,040,773
3	Gas	198,524,607	21,646,150	20,503,397			182/254	428,785	182/254	2,243,447	201,482,022
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	858,872,549	103,930,849	113,723,354				2,127,517		20,570,268	867,522,795
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	858,872,549	103,930,849	113,723,354				2,127,517		20,570,268	867,522,795
10	Classification of TOTAL										
11	Federal Income Tax	709,431,469	82,722,533	94,867,345				2,057,115		18,572,250	713,801,792
12	State Income Tax	149,441,080	21,208,316	18,856,009				70,402		1,998,018	153,721,003
13	Local Income Tax										

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty
The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2024, is \$3,530,683 and the Coal Combustion Residual ARO balance is \$1,828,434. The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2024, is \$(264,879,910). 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 \$3,802,945.
(b) Concept: AccumulatedDeferredIncomeTaxesOtherProperty
The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2024, is \$9,567,765. The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2024, is \$(73,989,360). Please see Footnote 6, Income and Other Taxes, within the Notes to Financial Statements for additional detail
(c) Concept: AccumulatedDeferredIncomeTaxesOtherProperty
The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2025, is \$3,393,249 and the Coal Combustion Residual ARO balance is \$760,483. The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2025, is \$(248,251,822). 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, 2025, is \$4,346,584
(d) Concept: AccumulatedDeferredIncomeTaxesOtherProperty
The ARO balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2025, is \$8,646,995. The Regulatory Tax Adjustments balance in Accumulated Deferred Income Taxes - Other Property (282) at December 31, 2025, is \$(72,174,698). Please see Footnote 6, Income and Other Taxes, within the Notes to Financial Statements for additional detail.

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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)
			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)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	AMI O&M KPSC Reg Asset	2,433,686	1,234,384	49,850							3,618,220
4	Asset Retirement Obligation - Electric	1,993,971	315,453	12,739							2,296,685
5	Coal Combustion Residual ARO	18,865,219	344,855	995,846							18,214,228
6	Emission Allowances	39									39
7	FAC Under Recovery KY	149,451	845,363	150,755							844,059
8	Interest Rate Swaps	5,061,750	94,879	321,119							4,835,510
9	Regulatory Tax Adjustment	2,190,017					182	91,628	182	1,185,666	3,284,055
10	Pension - Regulatory Asset	34,458,146	92,269	2,284,718							32,265,697
11	Prepaid Insurance	534,848	2,238	55,415							481,671
12	Loss on Reacquired Debt	2,310,571	9,368	231,958							2,087,981
13	Pensions	4,998,510	2,758,496	111,401							7,645,605
14	Plant Outage Normalization - Reg Asset	1,796,313	25,758	637,823							1,184,248
15	RAR Tracker Reg Asset	20,742,728	70,493	1,745,537							19,067,684
16	Rate Case Expenses	22,138	303,960	55,074							271,024
17	Storm Damages	4,882,181	1,240,890	284,886							5,838,185
18	Swap Termination	2,303,256	9,951	246,395							2,066,812
19	Other										
9	TOTAL Electric (Total of lines 3 thru 8)	102,742,824	7,348,357	7,183,516				91,628		1,185,666	104,001,703
10	Gas										
11	AMI O&M KPSC Reg Asset	962,138	703,601	265,389							1,400,350
12	Asset Retirement Obligation - Gas	2,453,822	524,785	165,789							2,812,818
13	Demand Side Management Reg Asset	161,176	2,847	70,460							93,563
14	Gas Line Tracker - Regulatory Asset	1,120,255	179,400	7,245							1,292,410
15	Interest Rate Swaps	1,265,374	23,720	80,279							1,208,815
16	Regulatory Tax Adjustment	288,417					182	9,112	182	225,612	504,917
17	Loss on Reacquired Debt	(7,722)	1,799	44,512							(50,435)
18	Pensions	740,665	823,966	33,276							1,531,355
19	Purchased Gas	638,517	1,846,416	74,567							2,410,366
20	Pension - Regulatory Asset	10,292,693	27,560	682,448							9,637,805
21	Prepaid Insurance	125,462	525	12,999							112,988
22	Rate Case Expenses	10,158	85,353	3,447							92,064

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
			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)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
23	Other										
17	TOTAL Gas (Total of lines 11 thru 16)	18,050,955	4,219,972	1,440,411				9,112		225,612	21,047,016
18	TOTAL Other						—		—		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	120,793,779	11,568,329	8,623,927				100,740		1,411,278	125,048,719
20	Classification of TOTAL										
21	Federal Income Tax	96,586,609	9,407,101	7,052,760				92,314		1,140,220	99,988,856
22	State Income Tax	24,207,170	2,161,228	1,571,167				8,426		271,058	25,059,863
23	Local Income Tax										
NOTES											
Page 276-277											

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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		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	ASC 740 - Income Taxes	448,988,698	410/411/190/282	18,380,000	(130,603)	430,478,095
2	Forward Starting Swaps Gains	27,071,472	427	1,433,703		25,637,769
3	ASC 715 - Pension and Postretirement	18,923,669	926/107	244,758	(2,372,464)	16,306,447
4	Off-System Sales Tracker	156,000	440-445	3,991,000	5,507,000	1,672,000
5	AMI Legacy Meters	679,738			1,061,449	1,741,187
6	Gas Supply Clause		480-482	16,762,561	16,762,561	
7	DSM Cost Recovery	7,089,000	440-445	2,579,000	3,241,000	7,751,000
8	AMI O&M Savings - Gas	1,761,460			2,927,557	4,689,017
9	AMI O&M Savings - Electric	1,622,506			2,431,067	4,053,573
10	Environmental Cost Recovery	6,263,000	440-445	6,723,000	3,675,000	3,215,000
11	Retired Asset Recovery Rider		440-445	425,000	840,000	415,000
41	TOTAL	512,555,543		50,539,022	33,942,567	495,959,088

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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 <i>Order/docket number:</i> KPSC 2025-00114 <i>Amortization Period :</i> Ongoing Forward Starting Swaps Gains <i>Order/docket number:</i> KPSC 2025-00114 <i>Amortization Period :</i> September 2015 to October 2045 ASC 715 - Pension and Postretirement <i>Order/docket number:</i> KPSC 2025-00114 FERC AI07-1-000 <i>Amortization Period :</i> Ongoing Off-System Sales Tracker <i>Order/docket number:</i> KPSC 2025-00114 807 KAR 5:506 <i>Amortization Period :</i> Ongoing AMI Legacy Meters <i>Order/docket number:</i> KPSC 2025-00114 Gas Supply Cause <i>Order/docket number:</i> KPSC 2025-00114 KPSC 2022-00083 <i>Amortization Period :</i> Ongoing DSM Cost Recovery <i>Order/docket number:</i> KRS 278.183 <i>Amortization Period :</i> Ongoing AMI O&M Savings - Gas <i>Order/docket number:</i> KPSC 2025-00114 AMI O&M Savings - Electric <i>Order/docket number:</i> KPSC 2025-00114 Environmental Cost Recovery <i>Order/docket number:</i> KRS 278.183 <i>Amortization Period :</i> Ongoing Retired Asset Recovery Rider <i>Order/docket number:</i> KPSC 2024-00317 FERC Docket AC25-21-000 <i>Amortization Period:</i> March 2025 to February 2035 for Mill Creek 1

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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	542,031,712	516,693,106	4,362,948	4,206,876	388,146	384,902
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	431,524,947	419,639,308	3,648,765	3,619,432	47,260	46,950
5	Large (or Ind.) (See Instr. 4)	178,424,353	178,817,825	2,301,735	2,379,447	550	549
6	(444) Public Street and Highway Lighting	1,334,293	1,418,250	5,868	6,775	502	519
7	(445) Other Sales to Public Authorities	107,471,117	103,107,041	1,062,045	1,056,098	4,809	4,817
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	1,260,786,422	1,219,675,530	11,381,361	11,268,628	441,267	437,737
11	(447) Sales for Resale	54,632,916	38,031,698	1,362,320	1,250,706	16	13
12	TOTAL Sales of Electricity	1,315,419,338	1,257,707,228	12,743,681	12,519,334	441,283	437,750
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	1,315,419,338	1,257,707,228	12,743,681	12,519,334	441,283	437,750
15	Other Operating Revenues						
16	(450) Forfeited Discounts	2,581,999	2,590,447				
17	(451) Miscellaneous Service Revenues	491,535	800,845				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	3,538,235	3,598,776				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	907,019	1,145,356				
22	(456.1) Revenues from Transmission of Electricity of Others	13,271,306	12,305,915				
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	20,790,094	20,441,339				
27	TOTAL Electric Operating Revenues	1,336,209,432	1,278,148,567				

Line12, column (b) includes \$ 5,683,397.00 of unbilled revenues.

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)
Line12, column (d) includes 22,982 MWH relating to unbilled revenues							
Page 300-301							

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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 going to FERC 444, Public Street and Highway Lighting.

(b) Concept: OtherElectricRevenue

Cash Settlements	\$	298,886
Other items less than \$250,000 each		608,133
Total for Other Electric Revenues (456)	\$	907,019

(c) Concept: RevenuesFromTransmissionOfElectricityOfOthers

East Kentucky Power Cooperative	\$	5,890,253
Kentucky Municipal Energy Agency		2,336,530
Kentucky Municipal Power Agency		1,336,343
Owensboro Municipal Utilities		1,196,159
Kentucky Utilities		822,370
Tennessee Valley Authority		691,027
Midcontinent Independent System Operator		332,788
City of Bardstown		327,785
City of Nicholasville		297,720
Other items less than \$250,000 each		40,331
Total for Revenues from Transmission of Electricity of Others (456.1)	\$	13,271,306

(d) Concept: OtherElectricRevenue

Sale of Renewable Energy Credit and Fees		381,339
Other items less than \$250,000 each		764,017
Total for Other Electric Revenues (456)	\$	1,145,356

(e) Concept: RevenuesFromTransmissionOfElectricityOfOthers

East Kentucky Power Cooperative	\$	5,673,003
Kentucky Municipal Energy Agency		2,274,267
Owensboro Municipal Utilities		1,198,131
Kentucky Municipal Power Agency		1,240,602
Tennessee Valley Authority		686,012
Midcontinent Independent System Operator		344,167
City of Bardstown		305,153
City of Nicholasville		298,509
Kentucky Utilities		251,470
Other items less than \$250,000 each		34,601
Total for Revenues from Transmission of Electricity of Others (456.1)	\$	12,305,915

(f) Concept: RevenueFromSalesOfElectricityUnbilled

This net unbilled revenue represents the following:		
Base Revenue	\$	2,442,000
Environmental Cost Recovery		3,048,000
Fuel Adjustment Clause		2,784,000
Solar Capacity Charge		2,397
Retired Asset Recovery		(415,000)
Demand Side Management		(662,000)
Off-system Sales Tracker		(1,516,000)
Net Unbilled	\$	5,683,397

(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.

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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					
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45					
46	TOTAL				

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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 (440)	4,336,489	536,760,326	389,914	11,122	0.1238
2	Residential Time-of-Day En Svc (440)	2,280	265,832	144	15,833	0.1166
3	Residential Time-of-Day Dem Svc (440)	328	32,072	5	65,600	0.0978
4	General Service (440)	879	125,311	252	3,488	0.1426
5	Lighting Service (440)	3,490	1,489,110	4,960	704	0.4267
6	Restricted Lighting Service (440)	1,283	311,353	1,482	866	0.2427
7	Duplicate Customers (440)			(8,611)		
8	Reclassifications and Adjustments (440)	1,270	137,797			0.1085
41	TOTAL Billed Residential Sales	4,346,019	539,121,801	388,146	11,197	0.1240
42	TOTAL Unbilled Rev. (See Instr. 6)	16,929	2,909,911			0.1719
43	TOTAL	4,362,948	542,031,712	388,146	11,240	0.1242

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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 \$6,140,436
(c) Concept: ResidentialSalesBilled
Includes fuel adjustment clause of \$3,243
(d) Concept: ResidentialSalesBilled
Includes fuel adjustment clause of \$518
(e) Concept: ResidentialSalesBilled
Includes fuel adjustment clause of \$1,144
(f) Concept: ResidentialSalesBilled
Includes fuel adjustment clause of \$5,422
(g) Concept: ResidentialSalesBilled
Includes fuel adjustment clause of \$1,991

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SALES OF ELECTRICITY BY RATE SCHEDULES

- 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.
- 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.
- 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.
- 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).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- 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 (442)	102	12,076	84	1,214	0.1184
2	General Service (442)	1,088,419	161,444,507	44,561	24,425	0.1483
3	Power Service (442)	1,066,778	128,802,779	2,202	484,459	0.1207
4	Time-of-Day Secondary Service (442)	963,886	86,926,612	392	2,458,893	0.0902
5	Time-of-Day Primary Service (442)	480,421	40,452,253	58	8,283,121	0.0842
6	Lighting Service (442)	28,381	7,614,259	9,511	2,984	0.2683
7	Restricted Lighting Service (442)	12,338	4,250,917	2,331	5,293	0.3445
8	Lighting Energy Service (442)	3	212	5	600	0.0707
9	Electric Vehicle Charging Service (442)	120	22,951	11	10,909	0.1913
10	General Time-of-Day Service (442)	2,496	281,710	56		
11	Duplicate Customers (442)			(11,951)		
12	Reclassifications and Adjustments (442)	(1,248)	(159,601)			
41	TOTAL Billed Small or Commercial	3,641,696	429,648,675	47,260	77,057	0.1180
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	7,069	1,876,272			0.2654
43	TOTAL Small or Commercial	3,648,765	431,524,947	47,260	77,206	0.1183

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Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ 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 \$139
(c) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$1,594,112
(d) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$1,586,485
(e) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$1,451,660
(f) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$716,116
(g) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$43,855
(h) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$19,181
(i) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$5
(j) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$73
(k) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$3,772

Name of Respondent: Louisville Gas and Electric Company	This report is: (1)	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	☒ An Original (2) ☐ A Resubmission		

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.
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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 (442)	26,635	3,566,115	324	82,207	0.1339
2	Power Service (442)	93,093	12,911,590	172	541,238	0.1387
3	Time-of-Day Secondary Service (442)	291,121	28,644,997	96	3,032,510	0.0984
4	Time-of-Day Primary Service (442)	963,237	71,854,323	55	17,513,400	0.0746
5	Retail Transmission Service (442)	927,714	60,551,521	7	132,530,571	0.0653
6	Lighting Service (442)	1,132	209,977	241	4,697	0.1855
7	Restricted Lighting Service (442)	151	27,802	43	3,512	0.1841
8	Duplicate Customers (442)			(388)		
9	Reclassifications and Adjustments (442)	(1)	(7,438)			
41	TOTAL Billed Large (or Ind.) Sales	2,303,082	177,758,887	550	4,187,422	0.0772
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(1,347)	665,466			(0.4940)
43	TOTAL Large (or Ind.)	2,301,735	178,424,353	550	4,184,973	0.0775

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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 \$40,211
(c) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$143,756
(d) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$448,754
(e) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$1,506,529
(f) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$1,537,759
(g) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$1,766
(h) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled
Includes fuel adjustment clause of \$233

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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 (444)	1	910	45	22	0.9100
2	Lighting Service (444)	1,968	540,503	329	5,982	0.2746
3	Restricted Lighting Service (444)	1,693	569,391	340	4,979	0.3363
4	Lighting Energy Service (444)	1,034	81,335	64	16,156	0.0787
5	Traffic Energy Service (444)	1,223	144,924	36	33,972	0.1185
6	Duplicate Customers (444)			(312)		
7	Reclassifications and Adjustments (444)		19,229			
41	TOTAL Billed Public Street and Highway Lighting	5,919	1,356,292	502	11,791	0.2291
42	TOTAL Unbilled Rev. (See Instr. 6)	(51)	(21,999)			0.4314
43	TOTAL	5,868	1,334,293	502	11,689	0.2274

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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 \$1
(c) Concept: PublicStreetAndHighwayLightingBilled
Includes fuel adjustment clause of \$2,986
(d) Concept: PublicStreetAndHighwayLightingBilled
Includes fuel adjustment clause of \$2,568
(e) Concept: PublicStreetAndHighwayLightingBilled
Includes fuel adjustment clause of \$1,610
(f) Concept: PublicStreetAndHighwayLightingBilled
Includes fuel adjustment clause of \$1,879

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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 (445)	2,255	297,329	495	4,556	0.1319
2	Volunteer Fire Department Service (445)	133	15,050	3	44,333	0.1132
3	General Service (445)	85,512	12,012,526	2,011	42,522	0.1405
4	Power Service (445)	159,218	21,280,978	260	612,377	0.1337
5	Time-of-Day Secondary Service (445)	161,302	16,969,567	90	1,792,244	0.1052
6	Time-of-Day Primary Service (445)	473,582	36,009,661	29	16,330,414	0.0760
7	Retail Transmission Service (445)	82,404	7,651,302	6	13,734,000	0.0929
8	Lighting Service (445)	16,256	5,552,692	2,165	7,509	0.3416
9	Restricted Lighting Service (445)	8,583	2,647,150	726	11,822	0.3084
10	Lighting Energy Service (445)	3,359	264,218	178	18,871	0.0787
11	Traffic Energy Service (445)	2,052	234,479	1,332	1,541	0.1143
12	Outdoor Sports Lighting Service (445)	49	14,066	1	49,000	0.2871
13	Special Contracts (445)	66,979	4,544,490	2	33,489,500	0.0678
14	Duplicate Customers (445)			(2,489)		
15	Reclassifications and Adjustments (445)	(21)	(276,138)			
41	TOTAL Billed Other Sales to Public Authorities	1,061,663	107,217,370	4,809	220,766	0.1010
42	TOTAL Unbilled Rev. (See Instr. 6)	382	253,747			0.6643
43	TOTAL	1,062,045	107,471,117	4,809	220,845	0.1012

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Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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 \$3,282
(c) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of \$191
(d) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of \$127,733
(e) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of \$236,610
(f) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of \$243,344
(g) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of \$727,826
(h) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of \$136,238
(i) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of \$25,073
(j) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of \$13,137
(k) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of \$5,242
(l) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of \$3,130
(m) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of \$81
(n) Concept: OtherSalesToPublicAuthoritiesBilled
Includes fuel adjustment clause of \$101,409

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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	11,358,379	1,255,103,025	441,267	25,740	0.1105
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	22,982	5,683,397			0.2473
43	TOTAL - All Accounts	11,381,361	1,260,786,422	441,267	25,740	0.1108

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

SALES FOR RESALE (Account 447)

- 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).
- Enter the name of the purchaser 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 purchaser.
- 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 long-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.
- 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).
- 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.
- 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.
- Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
- 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.
- 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.
- 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)		Megawatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)	
1	Altop Energy Trading LLC	OS	(3)				1,061		79,247		79,247
2	Associated Electric Cooperative Inc.	OS	(3)				722		36,186		36,186
3	Big Rivers Electric Corp	OS	(17)							35	35
4	Constellation Energy Generation, LLC	OS	(3)				856		39,770		39,770
5	Dominion Energy South Carolina, Inc.	OS	(3)				636		34,188		34,188
6	Duke Energy Carolinas, LLC	OS	(3)				7,849		432,451		432,451
7	Duke Energy Florida, LLC	OS	(3)				1,112		60,549		60,549
8	Dynasty Power, Inc.	OS	(3)				488		31,107		31,107
9	East Kentucky Power Cooperative, Inc.	OS	(SA4)				1,925		72,353	68,552	140,905
10	Evergy Kansas Central, Inc.	OS	(3)				312		19,210		19,210
11	Hoosier Energy Rural Electric Coop	OS	(17)							386	386
12	Indiana Municipal Power Agency	OS	(CB SA4)				292		13,437		13,437
13	Indiana Municipal Power Agency	OS	(SA 3)				642		26,315		26,315
14	Kentucky Municipal Energy Agency	OS	(SA 23)				3,582		137,902	344,482	482,384
15	Kentucky Municipal Power Agency	OS	(17)				328		14,655	196,271	210,926

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 Sold (g)	REVENUE			Total (\$) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)	
16	^(b) Kentucky Utilities Company	SF	^(a) (RS 508)				1,011,588		28,908,163		28,908,163
17	Kentucky Utilities Company	SF	^(a) (17)							^(a) 9,100	9,100
18	Macquarie Energy LLC	⁽ⁱ⁾ OS	^(a) (3)				18,820		1,105,003	^(a) 100	1,105,103
19	Midcontinent Independent System Operator	^(a) OS	^(a) (3)				119,982		8,330,944		8,330,944
20	North Carolina Electric Membership Corporation	⁽ⁱ⁾ OS	^(a) (3)				1,381		68,585		68,585
21	Owensboro Municipal Utilities	^(a) OS	^(a) (SA 15)				665		35,810	^(a) 192,927	228,737
22	PJM Settlement, Inc.	⁽ⁱ⁾ OS	^(a) (3)				131,182		11,090,653		11,090,653
23	Rainbow Energy Marketing Corporation	^(a) OS	^(a) (3)				41,879		2,385,060		2,385,060
24	Southern Company Services, Inc.	⁽ⁱ⁾ OS	^(a) (3)				3,365		155,701		155,701
25	Tampa Electric Company	^(a) OS	^(a) (3)				2		76		76
26	Tennessee Valley Authority	⁽ⁱ⁾ OS	^(a) (3)				10,719		560,237		560,237
27	Tennessee Valley Authority	^(a) OS	^(a) (SA 11)				28		1,048	^(a) 8,230	9,278
28	The Energy Authority, Inc.	^(a) OS	^(a) (3)				2,478		155,116		155,116
29	The Energy Authority, Inc.	^(a) OS	^(a) (10)				426		19,067		19,067
15	Subtotal - RQ										
16	Subtotal-Non-RQ						1,362,320		53,812,833	820,083	54,632,916
17	Total						1,362,320		53,812,833	820,083	54,632,916
Page 310-311											

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
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: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
LG&E and KU 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
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
(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
Market Based Sales
(s) Concept: StatisticalClassificationCode
Market Based Sales
(t) Concept: StatisticalClassificationCode
Market Based Sales
(u) 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
(v) Concept: StatisticalClassificationCode
Market Based Sales

(w) Concept: StatisticalClassificationCode
Market Based Sales
(x) Concept: StatisticalClassificationCode
Market Based Sales
(y) Concept: StatisticalClassificationCode
Market Based Sales
(z) Concept: StatisticalClassificationCode
Market Based Sales
(aa) Concept: StatisticalClassificationCode
Schedule 4 Energy Imbalance Service Schedule 2 Reactive Supply and Voltage Control Schedule 12 Distribution of Penalty Revenues
(ab) Concept: StatisticalClassificationCode
Market Based Sales
(ac) Concept: StatisticalClassificationCode
Cost Based Sales
(ad) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(ae) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(af) Concept: RateScheduleTariffNumber
(17) LG&E and KU Joint ProForma Open Access Transmission Tariff Attachment F ProForma NITSA
(ag) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(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
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(ak) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(al) Concept: RateScheduleTariffNumber
(SA 4) LG&E and KU Joint ProForma Open Access Transmission Tariff - Attachment F NITSA FERC No. 4
(am) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(an) Concept: RateScheduleTariffNumber
(17) LG&E and KU Joint ProForma Open Access Transmission Tariff - Attachment F ProForma NITSA
(ao) Concept: RateScheduleTariffNumber
(CB SA4) LG&E and KU Cost Based Rate CBR Tariff Service Agreement No. 4
(ap) 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
(aq) Concept: RateScheduleTariffNumber
(SA 23) LG&E and KU Joint ProForma Open Access Transmission Tariff - Attachment F NITSA FERC No. 23
(ar) Concept: RateScheduleTariffNumber
(17) LG&E and KU Joint ProForma Open Access Transmission Tariff ProForma Attachment F NITSA
(as) Concept: RateScheduleTariffNumber
(RS 508) Effective June 4, 2018 LG&E and KU Joint Rate Schedule No. 508 Amended and Restated Power Supply System Agreement.
(at) Concept: RateScheduleTariffNumber
(17) LG&E and KU Joint ProForma Open Access Transmission Tariff Attachment F ProForma NITSA
(au) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(av) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(aw) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(ax) Concept: RateScheduleTariffNumber
(SA 15) LG&E and KU Joint ProForma Open Access Transmission Tariff - Attachment F NITSA FERC No. 15
(ay) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(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
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(bd) Concept: RateScheduleTariffNumber
(SA 11) LG&E and KU Joint ProForma Open Access Transmission Tariff - Attachment F NITSA FERC No. 11
(be) Concept: RateScheduleTariffNumber
(3) LG&E and KU Joint Market Based Rate Tariff (MBRT) (Short Form Tariff)
(bf) Concept: RateScheduleTariffNumber
(10) LG&E and KU CBR Tariff ProForma Service Agreement
(bg) Concept: OtherChargesRevenueSalesForResale
Transmission revenues-Schedule 2
(bh) Concept: OtherChargesRevenueSalesForResale
Transmission revenues-Schedule 2, \$69,948; Transmission revenue credits-Schedule 12, \$1,396
(bi) Concept: OtherChargesRevenueSalesForResale
Transmission revenues-Schedule 2, \$393; Transmission revenue credits-Schedule 12, \$7
(bj) Concept: OtherChargesRevenueSalesForResale
Transmission revenues-Schedule 2, \$27,639; Schedule 3, \$77,297; Schedule 5, \$119,811; Schedule 6, \$119,811; Transmission revenue credits-Schedule 12, \$76
(bk) Concept: OtherChargesRevenueSalesForResale
Transmission revenues-Schedule 2, \$15,435; Schedule 3, \$44,151; Schedule 5, \$68,434; Schedule 6, \$68,434; Transmission revenue credits-Schedule 12, \$183
(bl) Concept: OtherChargesRevenueSalesForResale
Schedule 2 transmission revenues
(bm) Concept: OtherChargesRevenueSalesForResale
LG&E and KU Open Access Transmission Tariff ProForma Attachment B Non-Firm Point-to-Point
(bn) Concept: OtherChargesRevenueSalesForResale
Transmission revenues-Schedule 2, \$15,036; Schedule 3, \$43,431; Schedule 5, \$67,317; Schedule 6, \$67,317; Transmission revenue credits-Schedule 12, \$174
(bo) Concept: OtherChargesRevenueSalesForResale
Transmission revenues-Schedule 2, \$8,362; Transmission revenue credits-Schedule 12, \$132

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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	2,530,214	2,941,986
5	(501) Fuel	279,217,095	260,503,136
6	(502) Steam Expenses	4,262,748	3,622,573
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	3,883,698	3,537,677
10	(506) Miscellaneous Steam Power Expenses	18,275,718	16,237,099
11	(507) Rents	49,658	37,422
12	(509) Allowances	1	2
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	308,219,132	286,879,895
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	6,307,752	6,533,976
16	(511) Maintenance of Structures	3,992,809	3,790,058
17	(512) Maintenance of Boiler Plant	33,583,648	29,843,219
18	(513) Maintenance of Electric Plant	7,032,436	6,249,978
18.1	(513.1) Maintenance of Computer Hardware		
18.2	(513.2) Maintenance of Computer Software	142,525	
18.3	(513.3) Maintenance of Communication Equipment	15,124	
19	(514) Maintenance of Miscellaneous Steam Plant	2,064,498	1,906,549
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	53,138,792	48,323,780
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	361,357,924	335,203,675
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		
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		
38.1	(531.1) Maintenance of Computer Hardware		
38.2	(531.2) Maintenance of Computer Software		
38.3	(531.3) Maintenance of Communication Equipment		
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		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
43	Operation		
44	(535) Operation Supervision and Engineering	81,406	91,549
45	(536) Water for Power	35,985	40,180
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses	198,816	196,402
48	(539) Miscellaneous Hydraulic Power Generation Expenses	137,634	109,267
49	(540) Rents	389,186	412,535
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	843,027	849,933
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	2,189	
54	(542) Maintenance of Structures	160,213	255,345
55	(543) Maintenance of Reservoirs, Dams, and Waterways	366,120	453,616
56	(544) Maintenance of Electric Plant	487,492	512,270
56.1	(544.1) Maintenance of Computer Hardware		
56.2	(544.2) Maintenance of Computer Software		
56.3	(544.3) Maintenance of Communication Equipment	37	
57	(545) Maintenance of Miscellaneous Hydraulic Plant	74,596	85,348
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	1,090,647	1,306,579
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	1,933,674	2,156,512
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	173,997	179,743
63	(547) Fuel	61,135,730	49,572,255
64	(548) Generation Expenses	275,780	384,985
65	(549) Miscellaneous Other Power Generation Expenses	1,740,798	1,913,121
66	(550) Rents	8,337	9,281
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	63,334,642	52,059,385
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	333,644	379,593
70	(552) Maintenance of Structures	305,516	319,092
71	(553) Maintenance of Generating and Electric Plant	1,735,600	2,977,980
71.1	(553.1) Maintenance of Computer Hardware		
71.2	(553.2) Maintenance of Computer Software	56,992	
71.3	(553.3) Maintenance of Communication Equipment	895	
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	754,093	932,013
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	3,186,740	4,608,678
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	66,521,382	56,668,063
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	66,431,164	67,964,127
76.1	(555.1) Power Purchased for Storage Operations		
76.2	(555.2) Bundled Environmental Credits		
76.3	(555.3) Unbundled Environmental Credits		
77	(556) System Control and Load Dispatching	1,428,014	1,607,512
78	(557) Other Expenses	307,933	111,451
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	68,167,111	69,683,090
79.1	F. Solar Generation		
79.2	Operation		
79.3	(558.1) Operation Supervision and Engineering		
79.4	(558.2) Solar Panel Generation and Other Plant Operating Expenses		
79.6	(558.4) Rents		
79.7	TOTAL Operation (Enter Total of lines 79.3 thru 79.6)		
79.8	Maintenance		
79.9	(558.6) Maintenance Supervision and Engineering		
79.10	(558.7) Maintenance of Solar Panels, Structures, and Equipment		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
79.11	(558.8) Maintenance of Computer Hardware		
79.12	(558.9) Maintenance of Computer Software	640	
79.13	(558.10) Maintenance of Communication Equipment	1,133	
79.14	(558.11) Maintenance of Miscellaneous Solar Generation Plant		
79.15	TOTAL Maintenance (Enter Total of lines 79.9 thru 79.14)	1,773	
79.16	TOTAL Power Production Expenses-Solar (total of lines 79.7 & 79.15)	1,773	
79.17	G. Wind Generation		
79.18	Operation		
79.19	(558.13) Operation Supervision and Engineering		
79.20	(558.14) Wind Turbine Generation and Other Plant Operating Expenses		
79.21	(558.16) Rents		
79.22	TOTAL Operation (Enter Total of lines 79.19 thru 79.21)		
79.23	Maintenance		
79.24	(558.18) Maintenance Supervision and Engineering		
79.25	(558.19) Maintenance of Wind Turbines, Structures, and Equipment		
79.26	(558.20) Maintenance of Computer Hardware		
79.27	(558.21) Maintenance of Computer Software		
79.28	(558.22) Maintenance of Communication Equipment		
79.29	(558.23) Maintenance of Miscellaneous Wind Generation Plant		
79.30	TOTAL Maintenance (Enter Total of lines 79.24 thru 79.29)		
79.31	TOTAL Power Production Expenses-Wind (total of lines 79.22 & 79.30)		
79.32	H. Other Renewable Generation		
79.33	Operation		
79.34	(559.1) Operation Supervision and Engineering		
79.35	(559.2) Other Miscellaneous Generation and Other Plant Operating Expenses		
79.36	(559.3) Fuel		
79.37	(559.4) Rents		
79.38	TOTAL Operation (Enter Total of lines 79.34 thru 79.37)		
79.39	Maintenance		
79.40	(559.6) Maintenance Supervision and Engineering		
79.41	(559.7) Maintenance of Structures		
79.42	(559.9) Maintenance of Boilers		
79.43	(559.10) Maintenance of Generating and Electric Equipment		
79.44	(559.12) Maintenance of Computer Hardware		
79.45	(559.13) Maintenance of Computer Software		
79.46	(559.14) Maintenance of Communication Equipment		
79.47	(559.15) Maintenance of Miscellaneous Renewable Production Plant		
79.48	TOTAL Maintenance (Enter Total of lines 79.40 thru 79.47)		
79.49	TOTAL Power Production Expenses-Other Renewable (total of lines 79.38 & 79.48)		
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74, 79, 79.16, 79.31, & 79.49)	497,981,864	463,711,340
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,133,062	1,076,329
85	(561.1) Load Dispatch-Reliability	80,256	186,478
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,324,395	1,411,269
87	(561.3) Load Dispatch-Transmission Service and Scheduling	401,358	359,391
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	505,835	386,029
90	(561.6) Transmission Service Studies	1,734	27,502
91	(561.7) Generation Interconnection Studies	(2,594)	(542)
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	561,214	854,958
94	(563) Overhead Lines Expenses	147,179	195,545
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	1,994,336	634,493
Page 320-323			

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
97	(566) Miscellaneous Transmission Expenses	13,202,817	12,806,779
98	(567) Rents	105,643	104,141
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	19,455,235	18,042,372
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	2,532	
104	(569.2) Maintenance of Computer Software	592,358	863,024
105	(569.3) Maintenance of Communication Equipment	72,015	
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	626,172	919,257
108	(571) Maintenance of Overhead Lines	1,508,672	1,551,037
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	166,535	193,057
111	TOTAL Maintenance (Total of Lines 101 thru 110)	2,968,284	3,526,375
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	22,423,519	21,568,747
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	10,439	3,015
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	10,439	3,015
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software	26,539	25,721
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	26,539	25,721
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	36,978	28,736
131.1	4. ENERGY STORAGE EXPENSES		
131.2	Operation		
131.3	(577.1) Operation Supervision and Engineering		
131.4	(577.2) Operation of Energy Storage Equipment		
131.5	(577.3) Storage Fuel		
131.6	(577.4) Rents		
131.7	Total Operation (Lines 131.3 thru 131.6)		
131.8	Maintenance		
131.9	(578.1) Maintenance Supervision and Engineering		
131.10	(578.2) Maintenance of Energy Storage Equipment and Structures		
131.11	(578.3) Maintenance of Computer Hardware		
131.12	(578.4) Maintenance of Computer Software		
131.13	(578.5) Maintenance of Communication Equipment	1,968	
131.14	(578.6) Maintenance of Miscellaneous Other Energy Storage Plant		
131.15	Total Maintenance (Lines 131.9 thru 131.14)	1,968	
131.16	TOTAL Energy Storage Expenses (Total of 131.7 and 131.15)	1,968	
132	5. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,122,083	2,375,239
135	(581) Load Dispatching		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
136	(582) Station Expenses	614,634	886,783
137	(583) Overhead Line Expenses	4,014,633	3,292,921
138	(584) Underground Line Expenses	5,192,321	4,703,155
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	4,117,626	4,340,696
141	(587) Customer Installations Expenses	(49)	(140)
142	(588) Miscellaneous Expenses	7,879,878	6,902,331
143	(589) Rents	18,359	19,170
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	23,959,485	22,520,155
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	30,320	38,574
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	410,803	439,169
148.1	(592.2) Maintenance of Computer Hardware		
148.2	(592.3) Maintenance of Computer Software	899,727	
148.3	(592.4) Maintenance of Communication Equipment	35,615	
149	(593) Maintenance of Overhead Lines	14,193,817	14,616,861
150	(594) Maintenance of Underground Lines	2,265,238	1,979,763
151	(595) Maintenance of Line Transformers	2	1,181
152	(596) Maintenance of Street Lighting and Signal Systems	127,027	118,170
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant	948,883	921,896
155	TOTAL Maintenance (Total of Lines 146 thru 154)	18,911,432	18,115,614
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	42,870,917	40,635,769
157	6. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,651,752	1,664,258
160	(902) Meter Reading Expenses	963,032	2,695,064
161	(903) Customer Records and Collection Expenses	8,161,944	7,956,297
162	(904) Uncollectible Accounts	3,115,433	2,896,792
163	(905) Miscellaneous Customer Accounts Expenses	451,391	2,913
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	14,343,552	15,215,324
165	7. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	250,874	182,635
168	(908) Customer Assistance Expenses	9,081,633	6,540,226
169	(909) Informational and Instructional Expenses	822,924	1,063,917
170	(910) Miscellaneous Customer Service and Informational Expenses	778,445	814,800
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	10,933,876	8,601,578
172	8. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	3,080	1,929
176	(913) Advertising Expenses	46,655	76,684
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	49,735	78,613
179	9. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	20,264,229	19,896,994
182	(921) Office Supplies and Expenses	5,537,920	4,851,407
183	(Less) (922) Administrative Expenses Transferred-Credit	2,767,206	2,711,254
184	(923) Outside Services Employed	10,587,282	15,177,308
185	(924) Property Insurance	6,889,271	6,570,069
186	(925) Injuries and Damages	2,996,752	7,162,373
187	(926) Employee Pensions and Benefits	15,906,125	13,683,786

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
188	(927) Franchise Requirements	30,226	26,577
189	(928) Regulatory Commission Expenses	1,017,088	1,105,129
190	(929) (Less) Duplicate Charges-Cr.	192,880	166,150
191	(930.1) General Advertising Expenses	948,842	874,111
192	(930.2) Miscellaneous General Expenses	3,239,738	4,220,105
193	(931) Rents	1,315,012	1,375,607
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	65,772,399	72,066,062
195	Maintenance		
196	(935) Maintenance of General Plant	578,640	1,273,759
196.1	(935.1) Maintenance of Computer Hardware	1,122,353	
196.2	(935.2) Maintenance of Computer Software	8,849,817	
196.3	(935.3) Maintenance of Communication Equipment	502,987	
196.4	TOTAL Maintenance (Enter Total of lines 196 thru 196.3)	11,053,797	1,273,759
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196.4)	76,826,196	73,339,821
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 131.16, 156, 164, 171, 178, and 197)	665,468,605	623,179,928
Page 320-323			

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

PURCHASED POWER (Account 555)

- 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.
- 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.
- 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.

- 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.
- For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (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.
- Report in column (g) the megawatt-hours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatt-hours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatt-hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
- 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.
- 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.
- 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)		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)
1	880 Storage LLC	OS	(12)				51					1,547		1,547
2	Bullitt County Public Library	OS	(12)				87					2,595		2,595
3	DCL Inc	OS	(12)				83					2,502		2,502
4	Department of Military Affairs	OS	(12)				62					1,857		1,857
5	Duke Energy Florida, LLC	OS	(8)				8					1,094		1,094
6	East Kentucky Power Cooperative, Inc.	OS	(11)				1,932					73,442		73,442
7	East Kentucky Power Cooperative, Inc.	OS	(SA4)				618					18,506		18,506
8	Indiana Municipal Power Agency	OS	(SA3)				2,175					73,689		73,689
9	Kentucky Municipal Energy Agency	OS	(SA23)				3,674					99,291		99,291

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)
10	Kentucky Municipal Power Agency	OS	(17)				2,449					81,213		81,213
11	Kentucky Utilities Company	SF	(RS 508)				778,591					19,606,440		19,606,440
12	JP Morgan Chase and Co	OS	(12)				50					1,493		1,493
13	MSM Property LLC - SQF	OS	(12)				27					810		810
14	MSM Property LLC - LQF	OS	(12)				98					2,961		2,961
15	Ohio Valley Electric Corporation - Demand	OS	(6)								19,961,709			19,961,709
16	Ohio Valley Electric Corporation - Demand	AD	(6)										137,219	137,219
17	Ohio Valley Electric Corporation - Energy	OS	(6)				673,952					25,263,914		25,263,914
18	Ohio Valley Electric Corporation - Energy	AD	(6)										61,699	61,699
19	Owensboro Municipal Utilities	OS	(SA15)				1,546					50,885		50,885
20	Oxmoor Center Management Office	OS	(12)				222					6,705		6,705
21	PJM Settlement, Inc.	OS	(16)				4,274					231,023		231,023
22	Southern Company Services, Inc.	OS	(13)				37					5,539		5,539
23	Storage USA Inc	OS	(12)				119					3,603		3,603
24	Switzer Property Holdings, LLC	OS	(12)				45					1,335		1,335
25	Yorktown Senior House	OS	(12)				9					260		260
26	Yorktown Senior House II	OS	(12)				1					30		30
27	Tampa Electric Company	OS	(8)				59					2,596		2,596
28	Tennessee Valley Authority	OS	(8)				250					2,500		2,500
29	Tennessee Valley Authority	OS	(4)				314					34,398		34,398
30	Tennessee Valley Authority	OS	(SA11)				198					5,864		5,864
31	The Energy Authority	OS	(14)				20					2,385		2,385
32	Simpsonville Solar	OS	(12)									25,500		25,500

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)
33	Business Solar	OS	(12)									49		49
34	Net Metering Service-2	OS	(12)				9,526					666,511		666,511
35	Inadvertent Interchange									332,948				
15	TOTAL						1,480,477			332,948	19,961,709	46,270,537	198,918	66,431,164
Page 326-327														

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ 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
LG&E and KU are owned by LKE
(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Intercompany Power Agreement dated September 10, 2010. The Company owns 5.63% 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 5.63% 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 with Solar Array One located in Simpsonville, Kentucky.
(f) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Archdiocese of Louisville
(g) Concept: StatisticalClassificationCode
Small Capacity Cogeneration and Small Power Production Qualifying Facility
(h) Concept: StatisticalClassificationCode
Large Capacity Cogeneration and Large Power Production Qualifying Facility
(i) Concept: StatisticalClassificationCode
Large Capacity Cogeneration and Small Power Production Qualifying Facility
(j) Concept: StatisticalClassificationCode
Large Capacity Cogeneration and Small Power Production Qualifying Facility
(k) Concept: StatisticalClassificationCode
Market Based Purchases
(l) Concept: StatisticalClassificationCode
Market Based Purchases
(m) Concept: StatisticalClassificationCode
Imbalance.
(n) Concept: StatisticalClassificationCode
Imbalance.
(o) Concept: StatisticalClassificationCode
Imbalance.
(p) Concept: StatisticalClassificationCode
Imbalance
(q) Concept: StatisticalClassificationCode
Small Capacity Cogeneration and Small Power Production Qualifying Facility
(r) Concept: StatisticalClassificationCode
Small Capacity Cogeneration and Small Power Production Qualifying Facility
(s) Concept: StatisticalClassificationCode
Large Capacity Cogeneration and Large Power Production Qualifying Facility
(t) Concept: StatisticalClassificationCode
Available Energy and Available Power
(u) Concept: StatisticalClassificationCode
Available Energy and Available Power
(v) Concept: StatisticalClassificationCode
Imbalance
(w) Concept: StatisticalClassificationCode
Large Capacity Cogeneration and Large Power Production Qualifying Facility
(x) Concept: StatisticalClassificationCode
Market Based Purchases
(y) Concept: StatisticalClassificationCode
Market Based Purchases
(z) Concept: StatisticalClassificationCode
Large Capacity Cogeneration and Large 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
Market Based Purchases
(ae) Concept: StatisticalClassificationCode
Market Based Purchases
(af) Concept: StatisticalClassificationCode
Emergency Purchases
(ag) Concept: StatisticalClassificationCode
Imbalance
(ah) Concept: StatisticalClassificationCode
Market Based Purchases
(ai) Concept: StatisticalClassificationCode
Large Capacity Cogeneration and Large Power Production Qualifying Facility
(aj) Concept: StatisticalClassificationCode
Small Commercial Customers
(ak) Concept: StatisticalClassificationCode
Residential Customers
(al) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(am) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(an) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(ao) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(ap) Concept: RateScheduleTariffNumber
(8) EEI Master Power Purchase and Sale Agreement dated 8/15/2023
(aq) Concept: RateScheduleTariffNumber
(11) EEI Master Power Purchase and Sale Agreement dated September 14, 2006.
(ar) Concept: RateScheduleTariffNumber
(SA4) LG&E and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4. NITSA Service Agreement FERC No. 4
(as) Concept: RateScheduleTariffNumber
(SA3) LG&E and KU Joint Pro Forma Open Access Transmission Tariff Schedule 9. LTF PTP Service Agreement FERC No. 3
(at) Concept: RateScheduleTariffNumber
(SA23) LG&E and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4. NITSA Service Agreement FERC No. 23
(au) Concept: RateScheduleTariffNumber
(17) LG&E and KU Joint Pro Forma OATT - Effective 9/6/2023 ProForma Attachment F NITSA. Amended 5/30/2025.
(av) 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.
(aw) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(ax) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(ay) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(az) 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.
(ba) 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.
(bb) 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.
(bc) 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.
(bd) Concept: RateScheduleTariffNumber
(SA15) LG&E and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4. NITSA Service Agreement FERC No. 15

(b _e) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(b _f) Concept: RateScheduleTariffNumber
(16) Operating Agreement of PJM Interconnection, LLC Rate Schedule FERC No. 24
(b _g) Concept: RateScheduleTariffNumber
(13) EEI Master Power Purchase and Sale Agreement dated 12/7/2007
(b _h) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(b _i) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(b _j) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(b _k) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(b _l) Concept: RateScheduleTariffNumber
(8) EEI Master Power Purchase and Sale Agreement dated 11/4/2024
(b _m) Concept: RateScheduleTariffNumber
(8) EEI Master Power Purchase and Sale Agreement date 7/24/2024
(b _n) Concept: RateScheduleTariffNumber
(4) Contingency Reserve Sharing Agreement dated November 20, 2009.
(b _o) Concept: RateScheduleTariffNumber
(SA11) LG&E and KU Joint Pro Forma Open Access Transmission Tariff Schedule 4. NITSA Service Agreement FERC No. 11
(b _p) Concept: RateScheduleTariffNumber
(14) WSPP Agreement Effective 8/1/1996
(b _q) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(b _r) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(b _s) Concept: RateScheduleTariffNumber
(12) KPSC Standard Rate Rider
(b _t) Concept: OtherChargesOfPurchasedPower
December 2024 true-up of accrual estimate for both energy and demand charges made in January 2025.
(b _u) Concept: OtherChargesOfPurchasedPower
December 2024 true-up of accrual estimate for both energy and demand charges made in January 2025.

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

- 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.
- Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
- 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).
- 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.
- 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.
- 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.
- 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.
- Report in column (i) and (j) the total megawatthours received and delivered.
- 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.
- 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.
- 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						\$332,788	332,788
2	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	FNO	Joint OATT	East Kentucky Power Cooperative	East Kentucky Power Cooperative	129	799,259	799,259	5,390,632			5,390,632
3	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	NF	Joint OATT	East Kentucky Power Cooperative	East Kentucky Power Cooperative		81,041	81,041		499,621		499,621
4	Indiana Municipal Power Agency	Indiana Municipal Power Agency	MISO and PJM	OLF	Joint OATT	Trimble Unit 1	PJM and MISO		479,401	479,401				
5	Indiana Municipal Power Agency	Indiana Municipal Power Agency	MISO and PJM	LFP	Joint OATT	Trimble Unit 2	PJM and MISO		651,829	651,829				
6	Illinois Municipal Electric Agency	Illinois Municipal Electric Agency	Midwest ISO	OLF	Joint OATT	Trimble Unit 1	Midwest ISO		427,586	427,586				
7	Illinois Municipal Electric Agency	Illinois Municipal Electric Agency	Midwest ISO	LFP	Joint OATT	Trimble Unit 2	Midwest ISO		541,391	541,391				
8	LG&E Transactions	Various	Various	NF	Joint OATT	Various	Various					1,394,728		1,394,728
9	Hoosier Energy	Midwest ISO	Hoosier Energy	FNO	Joint OATT	Midwest ISO	Hoosier Energy	1	6,157	6,157	33,833			33,833
10	Kentucky Municipal Power Agency	Midwest ISO	Kentucky Municipal Power Agency	FNO	SA 13	Various	LGEE.KMPA	32	183,867	183,867	1,336,343			1,336,343
11	Owensboro Municipal Utilities	Owensboro Municipal Utilities	Various	FNO	SA 15	Owensboro Municipal Utilities	Various	31	194,674	194,674	1,196,160			1,196,160
12	Big Rivers Electric Corporation	Big Rivers Electric Corporation	Big Rivers Electric Corporation	FNO	Joint OATT	Big Rivers Electric Corporation	Big Rivers Electric Corporation		550	550	2,976			2,976

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)
13	Kentucky Municipal Energy Agency	Midwest ISO	Kentucky Municipal Energy Agency	FNO	Joint OATT	Various	LGEE.KYMEA	55	327,476	327,476	2,336,530			2,336,530
14	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	FNO	Joint OATT	Tennessee Valley Authority	Tennessee Valley Authority	17	84,938	84,938	690,936			690,936
15	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	NF	Joint OATT	Tennessee Valley Authority	Tennessee Valley Authority		9	9		90		90
16	The Energy Authority	The Energy Authority	The Energy Authority	NF	Joint OATT	Tennessee Valley Authority	Tennessee Valley Authority					2		2
17	Macquarie	Various	Various	NF	Joint OATT	Midwest ISO	Various		1,139	1,139		7,117		7,117
18	City of Bardstown	Various	City of Bardstown	FNO	185	Various	City of Bardstown	8			327,785			327,785
19	City of Nicholasville	Various	City of Nicholasville	FNO	157	Various	City of Nicholasville	7			297,720			297,720
35	TOTAL							280	3,779,317	3,779,317	11,612,915	1,901,558	332,788	13,847,261 ⁴¹

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Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: PaymentByCompanyOrPublicAuthority		
LG&E transmits electricity for Indiana Municipal Power Agency (IMPA) from Trimble County Unit 1 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMPA. This agreement was reached between LG&E and IMPA as a result of LG&E's exit from the MISO.		
(b) Concept: PaymentByCompanyOrPublicAuthority		
LG&E transmits electricity for Indiana Municipal Power Agency (IMPA) from Trimble County Unit 2 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMPA. This agreement was reached between LG&E and IMPA as a result of LG&E's exit from the MISO.		
(c) Concept: PaymentByCompanyOrPublicAuthority		
LG&E transmits electricity for Illinois Municipal Electric Agency (IMEA) from Trimble County Unit 1 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMEA. This agreement was reached between LG&E and IMEA as a result of LG&E's exit from the MISO.		
(d) Concept: PaymentByCompanyOrPublicAuthority		
LG&E transmits electricity for Illinois Municipal Electric Agency (IMEA) from Trimble County Unit 2 to the MISO-LGEE interface or the PJM-LGEE interface at no cost to IMEA. This agreement was reached between LG&E and IMEA as a result of LG&E's exit from the MISO.		
(e) Concept: PaymentByCompanyOrPublicAuthority		
LG&E and KU are owned by LKE.		
(f) Concept: StatisticalClassificationCode		
The OLF transmission service agreement between LG&E and IMPA has a termination date of 11/01/2025 for Trimble County Unit 1.		
(g) Concept: StatisticalClassificationCode		
The LFP transmission service agreement between LG&E and IMPA has a termination date of 4/01/2027 for Trimble County Unit 2.		
(h) Concept: StatisticalClassificationCode		
The OLF transmission service agreement between LG&E and IMEA has a termination date of 3/01/2028 for Trimble County Unit 1.		
(i) Concept: StatisticalClassificationCode		
The LFP transmission service agreement between LG&E and IMEA has a termination date of 1/01/2030 for Trimble County Unit 2.		
(j) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers		
LG&E receives ongoing monthly payments from MISO in a Joint Party Settlement Agreement related to uncompensated MISO usage above the 1,000 MW contract right.		
(k) 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	\$	13,847,261
Elimination of intracompany transmission revenues		(575,955)
Schedule Page: 300, Line No.: 22, Column: b	\$	13,271,306

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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					
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43					

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)
44					
45					
46					
47					
48					
49					
40	TOTAL				
Page 331					

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

- 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.
- 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.
- 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.
- Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
- 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.
- Enter ""TOTAL"" in column (a) as the last line.
- 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	^(a) Kentucky Utilities (KU)	NF	244,987	244,987		1,858,054	^(g) 44,935	1,902,989
2	PJM Interconnect	LFP	2,894	2,894	23,892			23,892
3	PJM Interconnect	NF	12,221	12,221		13,966	^(g) 19,638	33,604
4	PJM Interconnect	OS					^(g) 414	414
5	Duke Energy Carolinas, LLC	NF				^(f) 4,544		4,544
6	Municipal Electric Authority of Georgia	NF				^(f) 909		909
7	South Carolina Public Service Authority	NF				^(f) 1,068		1,068
8	Southern Company Services, Inc	NF				^(f) 2,168		2,168
9	Tennessee Valley Authority	NF				^(f) 21,368		21,368
10	Duke Energy Progress, LLC	NF				^(f) 470		470
11	Georgia Transmission Corporation	NF				^(f) 2,113		2,113
12	Dominion Energy South Carolina Inc.	NF				^(f) 526		526
13	Duke Energy Florida, LLC	NF				^(f) 142		142
14	Jacksonville Electric Authority	NF				^(f) 123		123
15	Seminole Electric Cooperative	NF				^(f) 6		6
	TOTAL		260,102	260,102	23,892	1,905,457	64,987	1,994,336

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FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityTransmissionOfElectricityByOthers

LG&E and KU are owned by LKE.

(b) Concept: EnergyChargesTransmissionOfElectricityByOthers

SEEM transmission losses directly related to actual transmission expenses occurred on the SEEM platform.

(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: EnergyChargesTransmissionOfElectricityByOthers

SEEM transmission losses directly related to actual transmission expenses occurred on the SEEM platform.

(m) Concept: OtherChargesTransmissionOfElectricityByOthers

Schedule 1 and Schedule 2 charges.

(n) Concept: OtherChargesTransmissionOfElectricityByOthers

Schedule 1 and Schedule 2 charges.

(o) Concept: OtherChargesTransmissionOfElectricityByOthers

Black Start Service Charges.

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	534,999
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	414,170
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	400,074
8	Shared Services	27,377
9	Amortization of Regulatory Asset:	
10	Swap Termination (Wachovia)	307,505
11	Miscellaneous:	
12	Prepaid IT Subscriptions	(212,895)
13	Depreciation Reclass	849,688
14	Debt Expense for Revolvers	343,325
15	Commitment Fees on Revolvers	413,478
16	Internal Communications	8,359
17	Software Subscriptions	58,385
18	LG&E Center Move	93,035
19	Other Miscellaneous Expenses:	
20	8 Items <\$5,000	
21	Various Vendors	2,238
46	TOTAL	3,239,738

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)
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Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

(a) Concept: DepreciationAndAmortization
Depreciation rates were updated effective July 1, 2021 based on a depreciation study dated June 30, 2020.

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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.

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)	EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
						Department (f)	Account No. (g)	Amount (h)				
1	FERC - Annual Charge	627,777		627,777		Electric	928	627,777				
2	FERC Administrative Charges	372,920		372,920		Electric	928	372,920				
3	KPSC - Rate Case - Electric 2025-00014				88,732	Electric			997,538			1,086,270
4	KPSC - Rate Case - Gas 2025-00014				40,714	Gas			328,281			368,995
5	Other - Electric		16,391	16,391		Electric	928	16,391				
6	Other - Gas		4,569	4,569		Gas	928	4,569				
46	TOTAL	1,000,697	20,960	1,021,657	129,446			1,021,657	1,325,819			1,455,265

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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. Solar
 - f. Wind
 - g. Other renewable
 - h. Unconventional generation
 - i. Siting and heat rejection
 2. Transmission

- a. Overhead
 - b. Underground
 3. Distribution
 4. Regional Transmission and Market Operation
 5. Energy Storage
 6. Environment (other than equipment)
 7. Other (Classify and include items in excess of \$50,000.)
 8. 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		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	A(6): Other	Various R&D Internal Projects and Initiatives	(171,973)		107, 549, 930	(171,973)	
2	B(1) EPRI	General		16,112	930	16,112	
3	B(1) EPRI	Generation		753,714	107, 549	753,714	
4	B(1) EPRI	Distribution		141,805	588	141,805	
5	B(1) EPRI	Transmission		80,105	566	80,105	
6	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.		416,963	107, 549, 930	416,963	
7	Total		(171,973)	1,408,699		1,236,726	

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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	18,613,937		
4	Transmission	2,781,157		
5	Regional Market			
5.1	Energy Storage			
6	Distribution	7,294,942		
7	Customer Accounts	4,845,776		
8	Customer Service and Informational	911,964		
9	Sales			
10	Administrative and General	14,914,257		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	49,362,033		
12	Maintenance			
13	Production	11,919,208		
14	Transmission	540,661		
15	Regional Market			
15.1	Energy Storage	1,374		
16	Distribution	3,248,552		
17	Administrative and General	420,347		
18	TOTAL Maintenance (Total of lines 13 thru 17)	16,130,142		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	30,533,145		
21	Transmission (Enter Total of lines 4 and 14)	3,321,818		
22	Regional Market (Enter Total of Lines 5 and 15)			
22.1	Energy Storage (Enter Total of Lines 5.1 and 15.1)	1,374		
23	Distribution (Enter Total of lines 6 and 16)	10,543,494		
24	Customer Accounts (Transcribe from line 7)	4,845,776		
25	Customer Service and Informational (Transcribe from line 8)	911,964		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	15,334,604		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	65,492,175	16,945,820	82,437,995
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply	780,390		
34	Storage, LNG Terminaling and Processing	1,474,501		
35	Transmission	1,668,139		
36	Distribution	7,442,843		
37	Customer Accounts	3,664,965		
38	Customer Service and Informational	272,849		
39	Sales			
40	Administrative and General	5,799,866		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	21,103,553		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	1,822,253		
47	Transmission	696,315		
48	Distribution	5,906,169		
49	Administrative and General	197,811		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	8,622,548		
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)	780,390		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	3,296,754		
56	Transmission (Lines 35 and 47)	2,364,454		
57	Distribution (Lines 36 and 48)	13,349,012		
58	Customer Accounts (Line 37)	3,664,965		
59	Customer Service and Informational (Line 38)	272,849		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	5,997,677		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	29,726,101	7,905,530	37,631,631
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	95,218,276	24,851,350	120,069,626
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	15,911,794	19,541,597	35,453,391
69	Gas Plant	9,043,139	8,006,313	17,049,452
70	Other (provide details in footnote):	5,874,243	763,591	6,637,834
71	TOTAL Construction (Total of lines 68 thru 70)	30,829,176	28,311,501	59,140,677
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,573,197	1,434,761	4,007,958
74	Gas Plant	384,931	221,390	606,321
75	Other (provide details in footnote):	11,456	1,544	13,000
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,969,584	1,657,695	4,627,279
77	Other Accounts (Specify, provide details in footnote):			
78	Accounts Receivable			
79	Deferred Debits	350,541	111,806	462,347
80	Certain Civic, Political and Related Activities and Other	1,414,851	69,553	1,484,404
81	Accounts Receivable (Non-jurisdictional - Trimble County)	340,257	112,114	452,371
82		2,297,776	654,149	2,951,925
83				
84				
85				
86				
87				
88				
89				
90				
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92				
93				
94				
95	TOTAL Other Accounts	4,403,425	947,622	5,351,047
96	TOTAL SALARIES AND WAGES	133,420,461	55,768,168	189,188,629

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: SalariesAndWagesUtilityPlantConstructionOther
The balance consists of direct labor associated with plant construction charged to common utility plants.
(b) Concept: SalariesAndWagesPlantRemovalOther
The balance consists of direct labor associated with plant retirements/removals charged to common utility plants.
(c) Concept: SalariesAndWagesUtilityPlantConstructionOther
The balance consists of indirect and allocated local engineering labor associated with plant construction charged to common utility plants.

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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.

Response:

1. See table below.

2. See table below.

3. Depreciation - Electric \$14,401,163; Gas \$6,487,272. Amortization - Electric \$0; Gas \$308,682. Common Utility expense accounts are not maintained but such expenses are allocated to Electric and Gas Departments as follows:

Customer Accounts Expenses (excluding uncollectible accounts)

Allocated between departments based on average number of customers served by each department for the year ending December 31, 2024.

Customer Service and Informational Expenses

Allocated between departments based on gross revenues from ultimate consumers by departments for the twelve month period.

Administrative and General Expenses

The administrative and general expenses are allocated based on general measures of cost causation.

4. The property original cost studies made pursuant to the Uniform System of Accounts included a separate classification for Common Utility Plant. Orders were issued in connection with such studies by Public Service Commission of Kentucky on September 16, 1941, and January 5, 1945, and the Federal Power Commission on December 15, 1944.

	Common Utility Plant (a)		
	Allocation to Utility Department (b)		
	Electric	Gas	
Accounts 101 and 106			Balance End of Year
Intangible Plant			
301 Organization			\$ 83,782
303 Miscellaneous Intangible Plant			—
Total Intangible Plant			83,782
Common Plant			
389 Land and Land Rights			2,122,291
390 Structures and Improvements			150,546,323
391 Office and Furniture and Equipment			14,469,956
392 Transportation Equipment			676,682
393 Stores Equipment			1,053,710
394 Tools, Shop and Garage Equipment			3,937,278
396 Power Operated Equipment			949,767
397.1 Computer Hardware			20,647,562
397.2 Computer Software			104,708,457
397.3 Communication Equipment			50,167,892
398 Miscellaneous Equipment			111,699
Total Common Plant			\$ 349,391,617
Total Accounts 101 and 106			\$ 349,475,399
Account 107			87,744,886
Total Common Utility Plant (c)	\$ 292,676,257	\$ 144,544,028	\$ 437,220,285
	Accumulated Provision for Depreciation of Common Utility Plant		
Balance at end of year	\$ 87,860,955	\$ 41,365,270	\$ 129,226,225

(a) Common plant consists of land, structures and equipment of a general nature used by all departments not specifically assignable to one department, and includes offices, storerooms, communication, transportation and work equipment, etc.

(b) Based on estimated usage by departments.

(c) Amounts presented exclude \$14,771,654 of Property Under Operating Leases recorded related to adoption and implementation of ASC 842 - Leases.

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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, Purchase 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)		28,021	202,942	59
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(10,003,469)	(1,887,730)	(2,774,954)	(4,755,443)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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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)
46	TOTAL	(10,003,469)	(1,859,709)	(2,572,012)	(4,755,384)
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Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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		
Line No.	Type of Ancillary Service (a)	Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		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	260,102	MWH	43,493	1,679,110	MWH	463,852
2	Reactive Supply and Voltage	260,102	MWH	21,080	1,679,110	MWH	136,948
3	Regulation and Frequency Response				706,017	MWH	164,879
4	Energy Imbalance	10,660	MWH	329,448	7,170	MWH	288,084
5	Operating Reserve - Spinning				706,017	MWH	255,562
6	Operating Reserve - Supplement				706,017	MWH	255,562
7	Other			414			332,788
8	Total (Lines 1 thru 7)	530,864		394,435	5,483,441		1,897,675

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedAmount
The amount consists of Black Start services charges from MISO.
(b) Concept: AncillaryServicesSoldAmount
The amount consists of MISO Joint Party Settlement Payments.
(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: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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: Louisville Gas and Electric Company									
1	January	2,383	22	9	2,016	288	79			
2	February	2,225	21	8	1,834	312	79			
3	March	1,858	6	10	1,534	245	79			
4	Total for Quarter 1				5,384	845	237			
5	April	2,105	30	18	1,786	240	79			
6	May	2,289	15	17	1,986	224	79			
7	June	2,917	25	17	2,541	301	75			
8	Total for Quarter 2				6,313	765	233			
9	July	2,922	28	17	2,539	308	75			
10	August	2,873	19	17	2,490	308	75			
11	September	2,428	15	16	2,125	228	75			
12	Total for Quarter 3				7,154	844	225			
13	October	2,152	1	16	1,852	225	75			
14	November	1,778	11	8	1,461	242	75			
15	December	2,207	15	8	1,849	283	75			
16	Total for Quarter 4				5,162	750	225			
17	Total				24,013	3,204	920			

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 2026-03-19	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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)	11,381,361
3	Steam	10,330,672	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,362,320
5	Hydro-Conventional	219,537	25	Energy Furnished Without Charge	1,426
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	26,974
6.1	Solar	7,642	27	Total Energy Losses	546,778
6.2	Wind	32	27.1	Total Energy Stored	
6.3	Other Renewable		28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	13,318,859
7	Other	1,613,447			
8	Less Energy for Pumping				
9	Net Generation (Enter Total of lines 3 through 8)	12,171,330			
10	Purchases (other than for Energy Storage)	1,480,477			
10.1	Purchases for Energy Storage				
11	Power Exchanges:				
12	Received				
13	Delivered	332,948			
14	Net Exchanges (Line 12 minus line 13)	(332,948)			
15	Transmission For Other (Wheeling)				
16	Received	3,779,317			
17	Delivered	3,779,317			
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)	13,318,859			

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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: Louisville Gas and Electric Company					
29	January	1,236,048	166,004	2,017	22	9
30	February	1,007,942	109,660	1,840	20	10
31	March	924,762	53,087	1,534	6	10
32	April	913,301	63,659	1,794	29	16
33	May	962,113	70,864	1,986	15	17
34	June	1,227,722	78,363	2,541	25	17
35	July	1,447,305	90,163	2,541	28	18
36	August	1,273,648	74,477	2,524	19	15
37	September	1,090,097	104,346	2,132	15	17
38	October	951,514	99,930	1,873	2	17
39	November	1,080,134	241,285	1,515	10	19
40	December	1,204,273	210,482	1,862	15	9
41	Total	13,318,859	1,362,320			

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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Steam Electric Generating Plant Statistics

- Report data for plant in Service only.
- 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.
- Indicate by a footnote any plant leased or operated as a joint facility.
- If net peak demand for 60 minutes is not available, give data which is available, specifying period.
- If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
- 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.
- 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.
- If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
- 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.
- 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.
- 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.
- 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: ^(b) Brown CT	Plant Name: ^(b) Cane Run NGCC	Plant Name: ^(b) Mill Creek	Plant Name: ^(b) Paddy's Run CT	Plant Name: ^(b) Trimble County	Plant Name: ^(b) Trimble County CT
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Combustion Turbine	NGCC	Steam	Combustion Turbine	Steam	Combustion Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional	Conventional	Conventional	Conventional	Conventional
3	Year Originally Constructed	1999	2015	1972	1968	1990	2002
4	Year Last Unit was Installed	2001	2015	1982	2001	2011	2004
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	199.72	155.06	1,361.70	122.74	543.99	409.73
6	Net Peak Demand on Plant - MW (60 minutes)	145	153	1,185	111	110	368
7	Plant Hours Connected to Load	330	164	526	195	430	536
8	Net Continuous Plant Capability (Megawatts)	180	152	1,165	78	474	328
9	When Not Limited by Condenser Water	180	152	1,165	78	474	328
10	When Limited by Condenser Water	0					0
11	Average Number of Employees	3	9	192	1	93	3
12	Net Generation, Exclusive of Plant Use - kWh	92,959,000	1,128,235,000	7,183,287,000	35,442,000	3,147,385,000	356,811,000
13	Cost of Plant: Land and Land Rights	5,015	1,762	3,673,743	2,957	5,616,297	10,526
14	Structures and Improvements	1,506,876	18,125,760	167,436,838	2,555,621	177,074,891	11,932,076
15	Equipment Costs	86,777,472	123,361,887	2,172,844,210	47,859,518	948,202,193	128,736,766
16	Asset Retirement Costs		19,622	14,140,707	36,237	11,080,333	59,502
17	Total Cost (10-23)	88,289,363	141,509,031	2,358,095,498	50,454,333	1,141,973,714	140,738,870
18	Cost per KW of Installed Capacity (line 17/5) Including	442.0657	912.6082	1,731.7291	411.0668	2,099.2550	343.4917
19	Production Expenses: Oper, Supv, & Engr	42,245	131,751	1,385,474		1,144,740	0
20	Fuel	5,351,811	28,231,999	202,356,415	4,430,421	76,860,681	23,121,500
21	Coolants and Water (Nuclear Plants Only)	0					0
22	Steam Expenses	0		4,850,831		(588,083)	0
23	Steam From Other Sources	0					0
24	Steam Transferred (Cr)	0					0
25	Electric Expenses	59,633	1,627,237	2,772,678	68,663	1,111,019	261,045
26	Misc Steam (or Nuclear) Power Expenses	0		11,779,835		6,465,464	0
27	Rents	0		49,658	8,337		0
28	Allowances	0		1			0
29	Maintenance Supervision and Engineering	73,639	237,618	4,802,318	22,387	1,484,434	0
30	Maintenance of Structures	132,197	153,816	3,088,474	19,503	904,335	0
31	Maintenance of Boiler (or reactor) Plant	0		23,375,452		10,208,197	0
32	Maintenance of Electric Plant	327,717	1,185,016	5,262,707	492,120	1,927,379	513,887
33	Maintenance of Misc Steam (or Nuclear) Plant	0		1,124,164		940,334	0
34	Total Production Expenses	5,987,242	31,567,437	260,848,007	5,041,431	100,458,500	23,896,432
35	Expenses per Net kWh	0.0644	0.0280	0.0363	0.1422	0.0319	0.0670

35	Plant Name	Brown CT	Brown CT	Cane Run NGCC	Mill Creek	Mill Creek	Paddy's Run CT	Trimble County	Trimble County	Trimble County CT
36	Fuel Kind	Gas	Oil	Gas	Coal	Gas	Gas	Coal	Gas	Gas
37	Fuel Unit	Mcf	Barrels	Mcf	T	Mcf	Mcf	T	Mcf	Mcf
38	Quantity (Units) of Fuel Burned	1,099,475		7,138,701	3,173,579	220,824	417,242	2,014,261	113,571	3,967,999
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,025		1,065	11,820	1,065	1,065	11,307	1,065	1,065
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5		4	63	15	11	50	10	6
41	Average Cost of Fuel per Unit Burned	5		4	64	15	11	37	10	6
42	Average Cost of Fuel Burned per Million BTU	5		4	3	14	10	2	9	5
43	Average Cost of Fuel Burned per kWh Net Gen									
44	Average BTU per kWh Net Generation	12,123		6,739	10,445		12,538	14,472		11,844
Page 402-403										

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

[\(a\)](#) Concept: PlantName

LG&E owns 53% of Brown CT unit 5, a 123 MW unit, and 38% of Units 6 and 7, 177 MW each. The remaining percentages of Units 5, 6 and 7 are owned by KU. Brown CT units 5, 6, and 7 are peak load service units. The information presented here represents LG&E's share.

[\(b\)](#) Concept: PlantName

LG&E owns 22% of Cane Run NGCC, a 705 MW unit, with the remaining percentage owned by KU. The information presented here represents LG&E's share.

[\(c\)](#) Concept: PlantName

LG&E owns 100% of Paddy's Run Unit 12, a 33 MW unit, and 53% of Unit 13, a 170 MW unit. The remaining percentage of Unit 13 is owned by KU. Paddy's Run Units 12 and 13 are peak load service units. The information presented here represents LG&E's share.

[\(d\)](#) Concept: PlantName

Partnership Expenses included in Column c:

Line No.: 19	Production Expenses: Oper, Supv & Engr	\$	(381,581)
Line No.: 20	Fuel		(27,794,804)
Line No.: 22	Steam Expenses		115,545
Line No.: 25	Electric Expenses		(370,341)
Line No.: 26	Misc Steam Power Expenses		(2,155,158)
Line No.: 29	Maintenance Supervision and Engineering		(498,898)
Line No.: 30	Maintenance of Structures		(292,362)
Line No.: 31	Maintenance of Boiler Plant		(3,327,328)
Line No.: 32	Maintenance of Electric Plant		(553,720)
Line No.: 33	Maintenance of Misc Steam Plant		(313,284)
Line No.: 34	Total Production Expenses	\$	(35,571,931)
Total Power Production Expenses per Schedule Page: 402-403, SUM of Line No.: 34, Columns (Plants): Brown CT, Cane Run NGCC, Mill Creek, Paddy's Run CT, Trimble County, Trimble County CT, Plus IMEA/IMPA Partner Expenses			
		\$	463,370,980
Operation and Maintenance Expenses on Retired Plants			
			51,419
Maintenance Expenses on Solar Plant			
			28,841
IMEA-IMPA Partnership Expenses			
			(35,571,932)
Rounding			
			(2)
Total Power Production Expenses per Schedule Page: 320-321, Sum of Line No.: 21 & 74, Column: b		\$	427,879,306

[\(e\)](#) Concept: PlantName

LG&E owns 29% of Trimble County CT units 5 and 6 and 37% of Units 7, 8, 9 and 10. The remaining percentages for Units 5, 6, 7, 8, 9 and 10 are owned by KU. The total Nameplate Ratings for these units are 199 MW per unit and they are peak load services units. The information presented here represents LG&E's share.

[\(f\)](#) Concept: PlantKind

LG&E owns 75% of Trimble County Steam Unit 1, a 425 MW unit, with the remaining 25% owned by IMEA and IMPA. LG&E also owns 14.25% of Trimble County Steam Unit 2, a 629 MW unit, with the remaining percentages owned by KU, IMEA and IMPA. The information presented here represents LG&E's share.

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	(2) ☐ A Resubmission		

Hydroelectric Generating Plant Statistics
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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: Ohio Falls
1	Kind of Plant (Run-of-River or Storage)	Run-Of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional
3	Year Originally Constructed	1928
4	Year Last Unit was Installed	1928
5	Total installed cap (Gen name plate Rating in MW)	109.22
6	Net Peak Demand on Plant-Megawatts (60 minutes)	73
7	Plant Hours Connect to Load	4,868
8	Net Plant Capability (in megawatts)	
9	(a) Under Most Favorable Oper Conditions	109
10	(b) Under the Most Adverse Oper Conditions	0
11	Average Number of Employees	4
12	Net Generation, Exclusive of Plant Use - kWh	219,537,000
13	Cost of Plant	
14	Land and Land Rights	6
15	Structures and Improvements	23,516,337
16	Reservoirs, Dams, and Waterways	16,808,091
17	Equipment Costs	122,778,748
18	Roads, Railroads, and Bridges	102,286
19	Asset Retirement Costs	601,915
20	Total Cost (10-23)	163,807,383
21	Cost per KW of Installed Capacity (line 20 / 5)	1,500
22	Production Expenses	
23	Operation Supervision and Engineering	81,406
24	Water for Power	35,985
25	Hydraulic Expenses	0
26	Electric Expenses	198,816
27	Misc Hydraulic Power Generation Expenses	137,634
28	Rents	389,186
29	Maintenance Supervision and Engineering	2,189
30	Maintenance of Structures	160,213
31	Maintenance of Reservoirs, Dams, and Waterways	366,120
32	Maintenance of Electric Plant	487,528
33	Maintenance of Misc Hydraulic Plant	74,596
34	Total Production Expenses (total 23 thru 33)	1,933,673
35	Expenses per net kWh	0.0088

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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 Demand on Plant-Megawatts (60 minutes)	0
6	Plant Hours Connect to Load While Generating	0
7	Net Plant Capability (in megawatts)	0
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	0
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 (10-23)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
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

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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, pumped storage plants, and renewable 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, renewable, 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		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
1	Brown Solar	2016	3.90	4.0	6,110,000	9,952,236	2,551,855						Solar
2	Business Solar - Archdiocese of Louisville	2018	0.03	0.0	27,000	84,971	2,832,367			1,773			Solar
3	Simpsonville Solar	2019	0.92	0.9	1,505,000	2,861,239	3,096,579						Solar
4	Brown Wind	2023	0.03	0	32,000	394,003	12,160,586						Wind

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FOOTNOTE DATA

[\(a\)](#) Concept: InstalledCapacityOfPlant
The nameplate rating for Brown Photovoltaic Solar Unit represents 39% ownership of the 10 MW unit. The remaining percentage of the unit is owned by KU.

[\(b\)](#) Concept: InstalledCapacityOfPlant
The nameplate rating for Simpsonville Solar Array 1-5 represents 44% ownership of the 2.1 MW array. The remaining percentage of the array is owned by KU.

[\(c\)](#) Concept: InstalledCapacityOfPlant
The nameplate rating for Brown Wind Unit represents 36% ownership of the 0.09 MW unit. The remaining percentage of the unit is owned by KU.

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ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) and (b) report the name of the energy storage project and location.
3. In column (c), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In column (d) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (c) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In column (e) report MWHs lost during conversion, storage and discharge of energy.
6. In column (f) report the MWHs sold.
7. In column (g), 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 (h), 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 (i) and (j), report fuel costs for storage operations associated with self-generated power and other costs associated with self-generated power.
9. In column (l) 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)	Location of the Project (b)	MWHs (c)	MWHs delivered to the grid (d)	MWHs Lost During Conversion, Storage and Discharge of Energy (e)	MWHs Sold (f)	Revenues from Energy Storage Operations (g)	Power Purchased for Storage Operations (555.1) (Dollars) (h)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (i)	Other Costs Associated with Self-Generated Power (Dollars) (j)	Account for Project Costs (k)	Total Project Plant Costs (l)
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
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26												
27												
28												
29												
30												
31												
32												
33												
34												
35	TOTAL		0	0	0	0	0	0	0	0		0

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a) and (b) report the name of the energy storage project, and location.
3. In column (c), 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 (d), report operation expenses excluding fuel, (e), maintenance expenses, (f) fuel costs for storage operations and (g) 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 (h) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Location of the Project (b)	Project Cost (c)	Plant Operating Expenses				
				Operations (Excluding Fuel used in Storage Operations) (d)	Maintenance (e)	Cost of fuel used in storage operations (f)	Account No. 555.1, Power Purchased for Storage Operations (g)	Other Expenses (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
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29								
30								
31								
32								
33								
34								
35								
36	TOTAL			0	0	0	0	0

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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)
34	Fern Valley Sub	Okolona Sub	138	138	WP,SP	1.40	0.00	1	1272 mcm		439,833	439,833
35	Fern Valley	Watterson Sub	138	138	ST	3.92	1.36	1	795 mcm	2,054	57,683	59,737
36	Hurstbourne Sub	Bluegrass Sub	138	138	SP	2.02	0.00	1	1272 mcm	37,300	1,477,866	1,515,166
37	Knob Creek Sub	Tip Top Sub	138	138	ST,WP,CP	11.79	0.00	1	636 mcm	7,955	3,160,313	3,168,268
38	Lyndon South Sub	Middletown Sub	138	138	ST,SP	5.58	0.00	1	795 mcm	35,941	2,980,296	3,016,237
39	Magazine Sub	Hancock Sub	138	138	WP,SP	2.38	0.04	1	1272 mcm		3,586,194	3,586,194
40	Magazine Sub	Waterside West	138	138	ST,SP,WP	3.38	0.00	1	795 mcm	2,600	1,274,362	1,276,962
41	Manslick Sub	Mill Creek Sub	138	138	ST,WP	10.52	0.00	1	636 mcm	16,570	1,679,831	1,696,401
42	Middletown Sub	Centerfield Sub	138	138	ST,WP,SP	12.26	0.00	1	795 mcm	42,761	2,257,672	2,300,433
43	Mill Creek Sub	Ashby Sub	138	138	WP,SP	5.56	0.00	1	1272 mcm	528	2,627,619	2,628,147
44	Mill Creek Sub	Knob Creek Sub	138	138	ST,WP	2.80	3.59	1	636 mcm	10,855	428,693	439,548
45	Mill Creek Sub	Kosmosdale Prim. Meter Stn.	138	138	ST,WP,SP	1.27	0.44	2	840.2 mcm		1,354,891	1,354,891
46	Mud Lane Sub	Blue Lick Sub	138	138	SP	5.45	0.00	1	840.2 mcm	46,432	3,964,562	4,010,994
47	Okolona Sub	Mud Lane Sub	138	138	WP,SP	3.86	0.18	1	1272 mcm	79,825	1,363,940	1,443,765
48	Paddy's Run Sub	Campground	138	138	ST	0.45	0.00	1	795 mcm	1,455	64,872	66,327
49	Paddy's Run Sub	Dixie Sub	138	138	WP,SP	3.58	0.00	1	795 mcm	27,351	1,462,466	1,489,817
50	Paddy's Run Sub	Ohio Falls Sub	138	138	ST,WP,SP	12.41	0.39	3	300 mcm	81,226	3,812,293	3,893,519
51	Paddy's Run Sub	Paddy's West Sub	138	138	ST	0.69	0.12	2	954 mcm	2,763	1,108,087	1,110,850
52	Plainview Sub	Hurstbourne Sub	138	138	WP,SP	2.18	0.00	1	1272 mcm	3,591	795,004	798,595
53	Paddy's West Sub	PSI Connection Gallagher	138	138	SP	0.42	0.00	1	954 mcm		219,011	219,011
54	Northside Sub	Clifty Creek Sub	138	138	ST,SP	32.54	0.00	1	336.4 mcm	73,852	3,334,298	3,408,150
55	Northside Sub	Tower No. 43 at P.S.I. Connection	138	138	ST	0.19	0.04	1	954 mcm		45,884	45,884
56	Clifty Creek Sub	Tower No.220 Connection with CG&E Co.	138	138	ST	4.24	2.50	1	336.4 mcm	22,743	889,814	912,557
57	Watterson Sub	Middletown Sub	138	138	ST,WP	7.20	0.22	1	840.2 mcm		1,480,214	1,480,214
58	Tip Top Sub	Cloverport Sub	138	138	ST,WP,SP	32.81	2.74	1	397.5 mcm	48,020	4,523,992	4,572,012
59	Waterside West	Beargrass Sub	138	138	ST,SP	2.08	0.00	2	795 mcm	17,803	573,941	591,744
60	Waterside West	Beargrass Sub	138	138	SP	0.25	1.81	1	795 mcm		913,129	913,129
61	Mill Creek Sub	Cane Run Sub	138	138	ST,SP	1.55	13.15	1	954 mcm	20,979	1,156,470	1,177,449
62	Mill Creek	East Fort Knox	345	345	ST,SP	6.89	0.00	1	954 mcm	941,552	6,333,476	7,275,028
63	Middletown	Old Henry	138	138	SP	3.76	0.00	1	954 mcm		4,715,373	4,715,373
64	Old Henry	Collins	138	138	SP	3.80	0.20	1	954 mcm	10,100	2,116,725	2,126,825
65	Trimble County	Speed	345	345	ST,SP	2.48	0.00	1	954 mcm	188,845	15,468,099	15,656,944
66	Trimble County	Ghent	345	345	ST,SP	0.04	2.44	1	954 mcm	389,276	2,351,639	2,740,915
67	Kenzig Road	Northside	345	345	ST,SP	9.19	0.31	1	954 mcm		609,743	609,743
68	Kenzig Road	Speed Tap	345	345	SP	0.86	0.00	1	954 mcm		8,462,751	8,462,751
69	Kenzig Road	Ramsey Tap	345	345	SP	0.87	0.80	1	954 mcm		303,590	303,590
70	Overhead Lines under 132KV		69	69	ST,WP,SP,CP	230.37	54.65	0	Various	5,630,358	158,736,817	164,367,175

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)
71	Ashbottom Sub	Grade Lane Sub	138	138	Undg. (26)	0.58	0.00	1	1500 Kcmil cu		1,042,460	1,042,460
72	Waterside West	Canal Sub	138	138	Undg. (26)	0.75	0.00	1	1750 mcm ho		584,760	584,760
73	Magazine Sub	Waterside West	138	138	Undg. (26)	0.75	0.00	1	1500 mcm ho		584,626	584,626
74	Waterside West	Beargrass Sub	138	138	Undg. (26)	0.93	0.00	1	1500 mcm cu		1,659,275	1,659,275
75	Waterside West	Beargrass Sub	138	138	Undg. (26)	0.93	0.00	1	1500 mcm ho		1,465,974	1,465,974
76	Underground Lines under 132KV		69	69	Undg. (26)	2.77	0.00	0	Various		4,807,819	4,807,819
77	Exp Applicable to All Lines											
36	TOTAL					675.38	243.64	88		9,426,987	334,632,716	344,059,703
Page 422-423 Part 1 of 2												

Line No.	EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(m)	(n)	(o)	(p)
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Page 422-423 Part 2 of 2				

Line No.	EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(m)	(n)	(o)	(p)
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76				
77	147,179	1,508,672	105,643	1,761,494
36	147,179	1,508,672	105,643	1,761,494
Page 422-423 Part 2 of 2				

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
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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 completed 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	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)
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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)		(d)	(e)	(f)	(g)	(h)	(i)	(j)		(l)	(m)	(n)	(o)	(p)	(q)
43																	
44	TOTAL		0		0	0	0										
Page 424-425																	

Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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 (l), (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		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)
1	Aiken	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
2	Algonquin	Transmission	Unattended	138.00	69.00	13.80	140	1	0	NONE	0	0
3	Appliance Park	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
4	Ashbottom	Transmission	Unattended	138.00	69.00	13.80	224	2	0	NONE	0	0
5	Ashby	Transmission	Unattended	138.00	12.47	0.00	0	0	0	NONE	0	0
6	Beargrass	Transmission	Unattended	138.00	69.00	13.80	185	1	0	NONE	0	0
7	Beargrass Pumping	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
8	Bishop	Transmission	Unattended	69.00	12.47	0.00	0	0	0	NONE	0	0
9	Blue Lick, Brooks, Ky 1	Transmission	Unattended	345.00	138.00	0.00	448	1	0	NONE	0	0
10	Blue Lick, Brooks, Ky 2	Transmission	Unattended	345.00	161.00	0.00	450	1	1	NONE	0	0
11	Blue Lick, Brooks, Ky 3	Transmission	Unattended	138.00	69.00	13.80	112	1	0	NONE	0	0
12	Breckinridge	Transmission	Unattended	138.00	69.00	13.20	112	1	0	NONE	0	0
13	Buckner	Transmission	Unattended	345.00	0.00	0.00	0	0	0	NONE	0	0
14	Campground	Transmission	Unattended	138.00	13.80	0.00	0	0	0	NONE	0	0
15	Canal	Transmission	Unattended	136.80	66.00	14.00	90	1	0	NONE	0	0
16	Cane Run CT	Transmission	Unattended	345.00	138.00	13.80	450	1	0	NONE	0	0
17	Cane Run Switching	Transmission	Unattended	138.00	69.00	13.80	224	2	0	NONE	0	0
18	Centerfield	Transmission	Unattended	138.00	69.00	13.80	140	1	0	NONE	0	0
19	Clay	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
20	Clifton	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
21	Cloverport	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
22	Collins	Transmission	Unattended	138.00	69.00	13.20	149	1	0	NONE	0	0
23	Crestwood, Crestwood, Ky	Transmission	Unattended	69.00	12.47	0.00	0	0	0	NONE	0	0
24	Dahlia	Transmission	Unattended	69.00	12.47	0.00	0	0	0	NONE	0	0
25	Del Park	Transmission	Unattended	69.00	13.80	0.00	0	0	0	NONE	0	0
26	Dixie	Transmission	Unattended	138.00	12.47	0.00	0	0	0	NONE	0	0
27	Eastwood	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
28	Ethel	Transmission	Unattended	138.00	69.00	13.80	140	1	0	NONE	0	0
29	Fairmount	Transmission	Unattended	69.00	12.47	0.00	0	0	0	NONE	0	0
30	Farnsley	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
31	Fern Valley	Transmission	Unattended	138.00	69.00	13.80	80	2	0	NONE	0	0
32	Floyd	Transmission	Unattended	69.00	13.80	0.00	0	0	0	NONE	0	0
33	Ford	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
34	Frey's Hill	Transmission	Unattended	69.00	12.47	0.00	0	0	0	NONE	0	0
35	Grade Lane	Transmission	Unattended	138.00	13.80	0.00	0	0	0	NONE	0	0
36	Grady	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		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)
37	Hancock	Transmission	Unattended	138.00	69.00	13.80	140	1	0	NONE	0	0
38	Harmony Landing, near Goshen , Ky	Transmission	Unattended	69.00	12.47	0.00	0	0	0	NONE	0	0
39	Harrods Creek	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
40	Highland	Transmission	Unattended	69.00	12.47	0.00	0	0	0	NONE	0	0
41	Hillcrest	Transmission	Unattended	69.00	13.80	0.00	0	0	0	NONE	0	0
42	Hourstbourne	Transmission	Unattended	138.00	12.47	0.00	0	0	0	NONE	0	0
43	Jeffersontown	Transmission	Unattended	138.00	12.47	0.00	0	0	0	NONE	0	0
44	Kenwood	Transmission	Unattended	69.00	12.47	0.00	0	0	0	NONE	0	0
45	Kenzig Road	Transmission	Unattended	345.00	0.00	0.00	0	0	0	NONE	0	0
46	Knob Creek, near Shepherdsville, Ky	Transmission	Unattended	138.00	34.50	0.00	0	0	0	NONE	0	0
47	Lime Kiln	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
48	Lyndon	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
49	Lyndon South, Lyndon, Ky	Transmission	Unattended	138.00	69.00	13.80	140	1	0	NONE	0	0
50	Madison	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
51	Magazine	Transmission	Unattended	69.00	13.80	0.00	0	0	0	NONE	0	0
52	Manslick	Transmission	Unattended	138.00	12.47	0.00	0	0	0	NONE	0	0
53	Middletown 345, Middletown, Ky	Transmission	Unattended	345.00	138.00	0.00	1794	4	0	NONE	0	0
54	Middletown, Middletown, Ky	Transmission	Unattended	138.00	69.00	13.80	448	3	0	NONE	0	0
55	Mill Creek, Kosmosdale, Ky 1	Transmission	Unattended	345.00	138.00	13.80	672	2	1	NONE	0	0
56	Mill Creek, Kosmosdale, Ky 2	Transmission	Unattended	138.00	69.00	13.80	90	2	1	NONE	0	0
57	Mud Lane	Transmission	Unattended	138.00	69.00	13.80	120	1	0	NONE	0	0
58	Nachand	Transmission	Unattended	69.00	12.47	0.00	0	0	0	NONE	0	0
59	Northside, Jeffersonville, Indiana	Transmission	Unattended	345.00	138.00	13.80	448	1	0	NONE	0	0
60	Okolona	Transmission	Unattended	138.00	12.47	0.00	0	0	0	NONE	0	0
61	Old Henry	Transmission	Unattended	138.00	12.47	0.00	0	0	0	NONE	0	0
62	Oxmoor	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
63	Paddy's Run 1	Transmission	Unattended	161.00	138.00	0.00	200	1	0	NONE	0	0
64	Paddy's Run 2	Transmission	Unattended	138.00	69.00	14.00	187	1	0	NONE	0	0
65	Paddy's West - Indiana	Transmission	Unattended	345.00	138.00	13.80	448	1	0	NONE	0	0
66	Plainview	Transmission	Unattended	138.00	12.47	0.00	0	0	0	NONE	0	0
67	Pleasure Ridge Park	Transmission	Unattended	138.00	12.47	0.00	0	0	0	NONE	0	0
68	Redmon Road	Transmission	Unattended	345.00	0.00	0.00	0	0	0	NONE	0	0
69	Seminole	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
70	Shively	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
71	Skylight, Ky	Transmission	Unattended	69.00	12.47	0.00	0	0	0	NONE	0	0
72	Smyrna	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
73	South Park	Transmission	Unattended	69.00	34.50	0.00	0	0	0	NONE	0	0
74	Stewart	Transmission	Unattended	69.00	13.80	0.00	0	0	0	NONE	0	0
75	Taylor	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
76	Terry	Transmission	Unattended	69.00	12.47	0.00	0	0	0	NONE	0	0
77	Tip Top, Ky 1	Transmission	Unattended	138.00	69.00	13.20	33	1	0	NONE	0	0
78	Tip Top, Ky 2	Transmission	Unattended	138.00	69.00	37.00	45	1	1	NONE	0	0
79	Trimble County	Transmission	Unattended	345.00	138.00	0.00	448	2	1	NONE	0	0
80	Waterside West	Transmission	Unattended	138.00	0.00	0.00	0	0	0	NONE	0	0
81	Watterson	Transmission	Unattended	138.00	69.00	13.80	152	2	0	NONE	0	0
82	West County	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		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)
83	WHAS	Transmission	Unattended	69.00	12.47	0.00	0	0	0	NONE	0	0
84	Worthington	Transmission	Unattended	69.00	0.00	0.00	0	0	0	NONE	0	0
85	Total Transmission			11,337.80	3,069.47	353.00	8309	41	5			
86	Aiken	Distribution	Unattended	69.00	12.47	0.00	73	2	0	NONE	0	0
87	Algonquin	Distribution	Unattended	69.00	13.80	0.00	101	3	0	Ground Transformer	4	12
88	Ashbottom	Distribution	Unattended	138.00	13.80	0.00	60	2	0	Ground Transformer	2	10
89	Ashby	Distribution	Unattended	138.00	12.47	0.00	56	2	0	NONE	0	0
90	Bishop	Distribution	Unattended	69.00	12.47	0.00	28	1	0	NONE	0	0
91	Bluegrass	Distribution	Unattended	138.00	12.47	0.00	90	2	0	NONE	0	0
92	Brandenburg, near Brandenburg, Ky	Distribution	Unattended	69.00	12.47	0.00	11	1	0	NONE	0	0
93	Breckenridge 1	Distribution	Unattended	69.00	13.80	0.00	40	2	0	Ground Transformer	2	5
94	Breckenridge 2	Distribution	Unattended	69.00	12.47	0.00	84	3	0	NONE	0	0
95	Campground	Distribution	Unattended	138.00	13.80	0.00	45	1	0	Ground Transformer	1	5
96	Canal	Distribution	Unattended	69.00	13.80	0.00	60	2	0	Ground Transformer	2	8
97	Cane Run	Distribution	Unattended	69.00	13.80	0.00	36	1	1	Ground Transformer	9	60
98	Centerfield	Distribution	Unattended	138.00	12.47	0.00	90	2	0	NONE	0	0
99	Clay	Distribution	Unattended	69.00	13.80	0.00	53	2	0	Ground Transformer	2	10
100	Clifton 1	Distribution	Unattended	69.00	13.80	0.00	48	2	0	Ground Transformer	2	9
101	Clifton 2	Distribution	Unattended	69.00	12.47	0.00	56	2	0	NONE	0	0
102	Collins	Distribution	Unattended	69.00	12.47	0.00	56	2	0	NONE	0	0
103	Conestoga	Distribution	Unattended	69.00	12.47	0.00	28	1	0	NONE	0	0
104	Crestwood, Crestwood, Ky	Distribution	Unattended	69.00	12.47	0.00	56	2	0	NONE	0	0
105	Crop	Distribution	Unattended	13.80	4.16	0.00	12	2	0	NONE		
106	Dahlia	Distribution	Unattended	69.00	12.47	0.00	56	2	0	NONE	0	0
107	Del Park	Distribution	Unattended	69.00	13.80	0.00	45	1	0	Ground Transformer	1	5
108	Dixie	Distribution	Unattended	138.00	12.47	0.00	45	1	0	NONE	0	0
109	Eastwood West	Distribution	Unattended	69.00	12.47	0.00	45	1	0	NONE	0	0
110	Ethel 1	Distribution	Unattended	69.00	13.80	0.00	25	1	0	Ground Transformer	1	4
111	Ethel 2	Distribution	Unattended	69.00	12.47	0.00	56	2	0	NONE	0	0
112	Fairmount	Distribution	Unattended	69.00	12.47	0.00	73	2	0	NONE	0	0
113	Farnsley Shively, Ky	Distribution	Unattended	69.00	12.47	0.00	56	2	0	NONE	0	0
114	Fern Valley 1	Distribution	Unattended	138.00	13.80	0.00	78	2	0	Ground Transformer	2	9
115	Fern Valley 2	Distribution	Unattended	138.00	12.47	0.00	101	3	0	NONE	0	0
116	Floyd	Distribution	Unattended	69.00	13.80	0.00	90	2	0	Ground Transformer	1	5
117	Ford Truck Plant	Distribution	Unattended	69.00	12.47	0.00	134	2	1	NONE	0	0
118	Frey's Hill	Distribution	Unattended	69.00	12.47	0.00	73	2	0	NONE	0	0
119	Grade Lane	Distribution	Unattended	138.00	13.80	0.00	202	3	1	Ground Transformer	2	10
120	Grady	Distribution	Unattended	69.00	13.80	0.00	66	3	0	Ground Transformer	2	9
121	Hancock	Distribution	Unattended	138.00	12.47	0.00	45	1	0	NONE	0	0
122	Harmony Landing, near Goshen , Ky	Distribution	Unattended	69.00	12.47	0.00	28	1	0	NONE	0	0
123	Harrod's Creek	Distribution	Unattended	69.00	12.47	0.00	84	3	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)
124	Herman	Distribution	Unattended	13.80	4.16	0.00	11	2	0	NONE	0	0
125	Highland 1	Distribution	Unattended	69.00	12.47	0.00	45	1	0	Ground Transformer	1	5
126	Highland 2	Distribution	Unattended	69.00	13.80	0.00	34	1	0	NONE	0	0
127	Hillcrest 1	Distribution	Unattended	69.00	12.47	0.00	45	1	0	Ground Transformer	1	5
128	Hillcrest 2	Distribution	Unattended	69.00	13.80	0.00	34	1	0	NONE	0	0
129	Hurstbourne, Jeffersontown, Ky	Distribution	Unattended	138.00	12.47	0.00	90	2	0	NONE	0	0
130	International	Distribution	Unattended	138.00	12.47	0.00	90	2	0	NONE	0	0
131	Jeffersontown	Distribution	Unattended	138.00	12.47	0.00	90	2	0	NONE	0	0
132	Kenwood	Distribution	Unattended	69.00	12.47	0.00	56	2	0	NONE	0	0
133	Knob Creek, near Shepherdsville, Ky	Distribution	Unattended	138.00	34.50	14.00	30	1	0	NONE	0	0
134	Lime Kiln	Distribution	Unattended	69.00	12.47	0.00	45	1	0	NONE	0	0
135	Locust	Distribution	Unattended	69.00	12.47	0.00	45	1	0	NONE	0	0
136	Lyndon, Ky	Distribution	Unattended	69.00	12.47	0.00	28	1	0	NONE	0	0
137	Lyndon South	Distribution	Unattended	69.00	12.47	0.00	80	2	0	NONE	0	0
138	Lynn	Distribution	Unattended	13.80	4.16	0.00	12	2	0	NONE	0	0
139	Madison	Distribution	Unattended	69.00	13.80	0.00	134	3	0	Ground Transformer	2	10
140	Magazine 1	Distribution	Unattended	13.80	4.16	0.00	15	6	0	Ground Transformer	3	15
141	Magazine 2	Distribution	Unattended	69.00	13.80	0.00	111	3	0	NONE	0	0
142	Manslick	Distribution	Unattended	138.00	12.47	0.00	90	2	0	NONE	0	0
143	Mill Creek	Distribution	Unattended	138.00	12.47	0.00	28	1	0	Ground Transformer	2	19
144	Mud Lane	Distribution	Unattended	138.00	12.47	0.00	90	2	0	NONE	0	0
145	Nachand	Distribution	Unattended	69.00	12.47	0.00	84	3	0	NONE	0	0
146	Okolona	Distribution	Unattended	138.00	12.47	0.00	45	1	0	NONE	0	0
147	Old Henry	Distribution	Unattended	138.00	12.47	0.00	45	1	0	NONE	0	0
148	Oxmoor	Distribution	Unattended	69.00	12.47	0.00	56	2	0	NONE	0	0
149	Paddy's Run	Distribution	Unattended	138.00	13.80	0.00	145	3	0	Ground Transformer	5	70
150	Pirtle	Distribution	Unattended	13.80	4.16	0.00	14	2	0	NONE	0	0
151	Plainview	Distribution	Unattended	138.00	12.47	0.00	90	2	0	NONE	0	0
152	Pleasure Ridge Park	Distribution	Unattended	138.00	12.47	0.00	90	2	0	NONE	0	0
153	Seminole 1	Distribution	Unattended	69.00	12.47	0.00	45	1	0	NONE	0	0
154	Seminole 2	Distribution	Unattended	69.00	13.80	0.00	229	5	0	NONE	0	0
155	Seventh Street	Distribution	Unattended	13.80	4.16	0.00	14	2	0	NONE	0	0
156	Shepherdsville, Ky	Distribution	Unattended	69.00	12.47	0.00	21	2	0	NONE	0	0
157	Shively 1	Distribution	Unattended	69.00	12.47	0.00	45	1	0	Ground Transformer	1	5
158	Shively 2	Distribution	Unattended	69.00	13.80	0.00	25	1	0	NONE	0	0
159	Skylight, Ky	Distribution	Unattended	69.00	12.47	0.00	10	1	0	NONE	0	0
160	Smyrna	Distribution	Unattended	69.00	12.47	0.00	56	2	0	NONE	0	0
161	South Park 1	Distribution	Unattended	69.00	12.47	0.00	28	1	0	NONE	0	0
162	South Park 2	Distribution	Unattended	69.00	34.50	14.00	10	1	0	NONE	0	0
163	Southern	Distribution	Unattended	13.80	4.16	0.00	14	2	0	NONE	0	0
164	Stewart	Distribution	Unattended	69.00	12.47	0.00	34	2	0	NONE	0	0
165	Taylor	Distribution	Unattended	69.00	12.47	0.00	84	3	0	NONE	0	0
166	Terry	Distribution	Unattended	69.00	12.47	0.00	73	2	0	NONE	0	0
167	Tip Top	Distribution	Unattended	138.00	34.50	28.00	101	2	0	NONE	0	0
168	Waterside West	Distribution	Unattended	138.00	13.80	0.00	200	4	0	NONE	0	0
169	Watterson	Distribution	Unattended	138.00	12.47	0.00	73	2	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)
170	West Point	Distribution	Unattended	34.50	12.47	0.00	11	1	0	NONE	0	0
171	Western	Distribution	Unattended	13.80	4.16	0.00	14	2	0	NONE	0	0
172	Worthington	Distribution	Unattended	69.00	12.47	0.00	90	2	0	NONE	0	0
173	WHAS	Distribution	Unattended	69.00	12.47	0.00	20	2	0	NONE	0	0
174	19 Stations Less Than 10,000 Kva			0.00	0.00	0.00	152	27	15	NONE	0	0
175	Total Distribution			7,320.90	1,126.23	56.00	5506	194	18		48	290
176	Summary											
177	Transmission 79						8309	41	6		0	0
178	Distribution 97						5506	194	18		48	290
179	Total 176-62 shared=114						13815	235	24		48	290
180	Shared 62											
181	(1) Located in or near Louisville except as noted.											
183	Total											1,160

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Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		

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	Kentucky Utilities Company	107, 108 and 184	1,394,738
3	Direct-Indirect Labor	Kentucky Utilities Company	174, 182.3, 183.2, 184, 186, 408.1, 426.5, 500-502, 505, 506, 510-513, 513.3, 514, 535, 538, 542, 543, 544, 546, 548, 549, 551-553, 553.3, 554, 560, 562, 566, 569.3, 570, 571, 578.5, 580, 582-583, 584, 586, 588, 592, 593, 594, 598, 807, 814, 816, 817, 818, 821, 830, 832, 833, 834, 836, 837, 851, 856, 859, 863, 871, 874, 875, 876, 877, 878, 879, 880, 887, 889, 890, 891, 892, 894, 902, 903, 920, 922, 922, 925, 926, 935.1 and 935.3	9,081,087
4	Equipment and Facilities	Kentucky Utilities Company	151, 165, 173, 174, 183.2, 184, 426.5, 454, 493, 500, 502, 505, 506, 510, 512, 513, 513.3, 544, 548, 549, 553, 553.3, 554, 558.1, 560, 562, 566, 567.1, 569.2, 569.3, 570, 571, 578.5, 580, 582-584, 586, 588, 592-594, 596-598, 880, 887, 903, 921, 931, 935.1, 935.2 and 935.3	1,801,251
5	Materials and Fuels	Kentucky Utilities Company	163, 184, 501, 502, 506, 511-514, 549, 552-554, 570, 571, 580, 582, 583, 586, 588, 592-594, 856, 874, 880, 887, 892, 902 and 935.3	229,442
6	Office and Administrative Services	Kentucky Utilities Company	183.2, 184, 426.5, 500, 501, 506, 549, 566, 580, 586, 588, 590, 593, 598, 874, 880, 908, 920, 921, and 935.3	40,646
7	Outside Services	Kentucky Utilities Company	163, 165, 183.2, 184, 186, 426.4, 501, 502, 506, 511-514, 539, 549, 552-554, 570, 571, 580, 582-584, 586, 588, 592-594, 596, 856, 874, 878, 880, 887, 892, 902, 923, 930.2 and 935.3	1,086,014
8	Transmission	Kentucky Utilities Company	456.1 and 565	1,207,867
9	Capital Expenditures	LG&E and KU Services Company	107, 108 and 184	27,257,081
10	Direct-Indirect Labor	LG&E and KU Services Company	163, 182.3, 183.2, 184, 228.3, 408.1, 416, 426.4, 426.5, 500-502, 505, 506, 510-513, 513.3, 541, 544, 546, 549, 551, 553.3, 556, 558.1, 560, 561.1-561.3, 561.5-561.7, 562, 563, 566, 569.3, 570, 571, 580, 582, 583, 586, 588, 590, 592, 593, 598, 818, 850, 859, 878, 880, 887, 901-903, 905, 907, 908-910, 920, 925, 926, 930.2, 935.1 and 935.3	59,461,660
11	Equipment and Facilities	LG&E and KU Services Company	163, 165, 183.2, 184, 403, 416, 426.4, 426.5, 500-502, 506, 510, 511, 546, 549, 556, 560, 561.1, 562, 563, 566, 569.2, 570, 571, 580, 582, 583, 586, 588, 590, 592, 593, 598, 818, 850, 859, 877, 878, 880, 887, 894, 901-903, 905, 908, 910, 921, 923, 924, 930.2, 931, 935.1 and 935.2	11,489,481
12	Materials	LG&E and KU Services Company	163, 506, 573, 586, 588, 593, 598, 878, 880, 894, 901 and 935	475,246
13	Office and Administrative Services	LG&E and KU Services Company	183.2, 184, 416, 421, 421.2, 426.4, 426.5, 500, 501, 502, 506, 510-512, 539, 549, 553, 556, 560, 561.1, 561.2, 561.5, 562, 563, 566, 570, 571, 580, 582, 583, 586, 588, 590, 592, 593, 598, 814, 874, 878, 880, 887, 894, 901-903, 905, 907-910, 920, 921, 925, 928, 930.2 and 935	2,192,138
14	Outside Services	LG&E and KU Services Company	165, 183.2, 184, 186, 426.4, 426.5, 500-502, 506, 510, 511, 549, 554, 560, 561.1, 561.5, 561.7, 563, 566, 569.2, 569.3, 571, 573, 580, 582, 583, 586, 588, 592, 593, 597, 598, 863, 880, 887, 894, 903, 908, 910, 920, 921, 923, 930.2 and 935-935.3	12,432,048
15	Capital Expenditures	PPL Services Corporation	107, 108 and 500	70,106,684
16	Direct-Indirect Labor	PPL Services Corporation	163, 184, 408.1, 426.4, 426.5, 500, 506, 566, 569.2, 588, 593, 880, 901, 903, 905, 920, 924-926, 930.2, 935.1, 935.2, 560, 561.5, 569.1 and 183.2	27,804,987
17	Equipment and Facilities	PPL Services Corporation	165	22,043
18	Materials	PPL Services Corporation	163	2,128
19	Office and Administrative Services	PPL Services Corporation	184, 426.4, 426.5, 500, 506, 549, 566, 588, 880, 901, 903, 905, 908, 920, 921, 923-925, 930.2, 935, 935.1 and 935.2	3,981,433
20	Outside Services	PPL Services Corporation	184, 426.4, 426.5, 506, 566, 569.2, 571, 588, 593, 880, 901, 903, 905, 920, 921, 923, 925, 928, 930.2, 935, 935.1, 592, 182.3, 183.2 and 431	31,300,427
19				
20	Non-power Goods or Services Provided for Affiliated			
21	Capital Expenditures	Kentucky Utilities Company	107 and 108	23,431,224
22	Direct-Indirect Labor	Kentucky Utilities Company	174, 182.3, 183.2, 184, 408.1, 426.5, 500-502, 505, 506, 510-514, 535, 538, 542, 543, 544, 546, 548, 549, 551-553, 553.3, 554, 558.1, 560, 561.1, 562, 566, 569.3, 570, 571, 578.5, 580, 582, 583, 584, 586, 588, 592, 593, 594, 598, 807, 814, 816, 817, 818, 821, 830, 833, 834, 836, 837, 851, 856, 859, 863, 871, 874, 875, 876, 877, 878, 879, 880, 887, 889, 890, 891, 892, 894, 902, 908, 920, 925, 926, 930.2, 935.1 and 935.3	20,810,371
23	Equipment and Facilities	Kentucky Utilities Company	165, 183.2, 184, 426.5, 454, 493, 500, 506, 513, 513.3, 553, 553.3, 558.1, 560, 561.1, 566, 569.3, 571, 578.5, 580, 582, 583, 584, 586, 588, 592, 593, 594, 598, 807, 814, 816, 817, 818, 821, 830, 833, 834, 836, 837, 851, 856, 859, 863, 871, 874, 875, 876, 877, 878, 879, 880, 887, 889, 890, 891, 892, 894, 902, 908, 920, 925, 926, 930.2, 931, 935.1 and 935.3	865,340
24	Materials and Fuels	Kentucky Utilities Company	107, 163, 184, 501, 502, 506, 511-514, 539, 543, 548, 549, 552, 553, 554, 558.7, 570, 580, 582, 583, 586, 588, 592-594, 598, 817, 818, 821, 833, 834, 836, 837, 856, 863, 874, 875, 880, 887, 889, 891, 892, 902, 909 and 921	440,876
25	Office and Administrative Services	Kentucky Utilities Company	183.2, 184, 426.5, 500, 501, 506, 549, 566, 580, 583, 586, 588, 590, 593, 598, 880, 901, 902, 920, 921 and 935.3	59,129
26	Outside Services	Kentucky Utilities Company	163, 183.2, 500, 506, 511, 553, 566, 571, 580, 583, 588, 593, 594, 902, 910, 921 and 923	1,280,503

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)
27	Transmission	Kentucky Utilities Company	456.1 and 565	785,491
28	Capital Expenditures	LG&E and KU Services Company	107,108 and 184	291,119
29	Direct-Indirect Labor	LG&E and KU Services Company	184, 219, 408.1, 426.5, 500, 506, 510, 513.3, 558.1, 560, 566, 569.3, 588, 592, 880, 908, 920, 925, 926, 930.2, 935.1 and 935.3	1,090,249
30	Materials	LG&E and KU Services Company	586 and 921	519
31	Office and Administrative Services	LG&E and KU Services Company	426.5, 500, 506, 512, 566, 580, 586, 588, 593, 901, 902, 920 and 921	53,504
32	Outside Services	LG&E and KU Services Company	183.2, 184, 593, and 923	174,333
33	u See footnote for allocation process			
42				
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Name of Respondent: Louisville Gas and Electric Company	This report is: (1) ☒ An Original	Date of Report: 03/19/2026	Year/Period of Report End of: 2025/ Q4
	(2) ☐ A Resubmission		
FOOTNOTE DATA			

(a) Concept: DescriptionOfNonPowerGoodOrService

Costs between Louisville Gas and Electric Company and Kentucky Utilities 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.

(b) 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.

(c) 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.