

THIS FILING IS

Item 1:

An Initial (Original) Submission

OR

Resubmission No.



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

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

Exact Legal Name of Respondent (Company)

Kentucky Power Company

Year/Period of Report
End of: 2025/ Q4

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

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.)

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

- 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 Kentucky Power Company	02 Year/ Period of Report End of: 2025/ Q4
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03 Previous Name and Date of Change (If name changed during year)
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04 Address of Principal Office at End of Period (Street, City, State, Zip Code)
1 Riverside Plaza, Columbus, OH 43215-2373

05 Name of Contact Person Jason M. Johnson	06 Title of Contact Person Accountant
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07 Address of Contact Person (Street, City, State, Zip Code)
1 Riverside Plaza, Columbus, OH 43215-2373

08 Telephone of Contact Person, Including Area Code 614- 716-1000	09 This Report is An Original / A Resubmission (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 04/09/2026
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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 Heather Whitney	03 Signature Heather Whitney	04 Date Signed (Mo, Da, Yr) 04/09/2026
02 Title V.P. Controller		

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

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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	NA
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	NA
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	NA
18	Electric Plant Held for Future Use	214	NA
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	NA
22	Materials and Supplies	227	
23	Allowances and Environmental Credits	228	
24	Extraordinary Property Losses	230a	NA
25	Unrecovered Plant and Regulatory Study Costs	230b	NA
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	NA
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	
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	NA
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	NA
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	NA
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	NA
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	NA
65	Pumped Storage Generating Plant Statistics	408	NA
66	Generating Plant Statistics Pages	410	NA
66.1	Energy Storage Operations (Large Plants)	414	NA
66.2	Energy Storage Operations (Small Plants)	419	NA
67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	
69	Substations	426	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
Stockholders' Reports (check appropriate box)			
Stockholders' Reports Check appropriate box:			
<input type="checkbox"/> Two copies will be submitted			
<input type="checkbox"/> No annual report to stockholders is prepared			

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Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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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.

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: 1919-07-21

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.

(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.

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 ...Enter the date when such independent accountant was initially engaged:

(2)

No

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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.			

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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	Footnote				

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Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	(2) <input type="checkbox"/> A Resubmission		

FOOTNOTE DATA

(a) Concept: OfficerTitle

The following table provides summary information concerning compensation earned by our Chief Executive Officer, our Chief Financial Officer, the three other most highly compensated executive officers. We refer collectively to this group as the named executive officers (NEOs)

Name and Principal Position	Year	Salary \$(1)	Bonus \$(2)	Stock Awards \$(3)	Non-Equity Incentive Plan Compensation \$(4)	Change in Pension Value and Nonqualified Deferred Compensation Earnings \$(5)	All Other Compensation \$(6)	Total \$(5)
William J. Fehrman President and Chief Executive Officer	2025	1,505,769	1,150,000	29,339,782	4,290,000	35,685	280,288	36,601,524
Trevor I. Mihalik Executive Vice President and Chief Financial Officer	2025	930,000	—	10,883,680	1,525,000	—	142,619	13,481,299
Douglas A. Cannon President - AEP Transmission	2025	449,231	1,230,000	4,085,684	665,232	—	262,628	6,692,775
Robert B. Bertsen Executive Vice President, General Counsel, and Secretary	2025	378,462	1,187,000	3,305,432	492,200	—	102,135	5,465,229
Alicia R. Knapp President - Nuclear Development	2025	209,231	1,100,000	2,749,837	282,989	—	26,923	4,368,980

- Amounts in the salary column are composed of executive salaries earned for the year 2025, which include 261 days of pay for 2025, due to 1 additional workday in 2025 compared to a standard 260-day year.
- The 2025 amount in the bonus column for Mr. Fehrman reflects a negotiated payment in March 2025 to replace the value of his 2024 year-to-date short-term incentive compensation from his prior employer that he forfeited by accepting AEP employment. The amounts shown for Messrs. Cannon and Bertsen, and Ms. Knapp all reflect amounts negotiated pursuant to their AEP employment that offset compensation from their prior employers that they forfeited to accept AEP employment and also served as an inducement to accept AEP employment.
- The amounts reported in this column reflect the aggregate grant date fair value calculated in accordance with FASB ASC Topic 718, disregarding the effect of estimated forfeitures, for the performance shares and restricted stock units (RSUs) granted under our Long-Term Incentive Plan. See Note 15 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2025, for a discussion of the relevant assumptions used in calculating these amounts. The number of shares realized and the value of the performance shares, if any, will depend on the Company's performance during a three-year performance and vesting period, or for Mr. Fehrman, also a five-year performance and vesting period, and generally the participant's continued AEP employment through this period. The potential payout can range from 0% to 200% of the target number of performance shares, plus any dividend equivalents. The value of the three-year performance shares is based on two measures: a Board-approved cumulative operating earnings per share measure (Cumulative EPS 50%) and total shareholder return relative to peer companies (Relative TSR 50%). The grant date fair value of the performance shares that are based on Cumulative EPS was computed in accordance with FASB ASC Topic 718 and was measured based on the closing price of AEP's common stock on the grant date. The maximum amount payable for the 2025 performance shares that are based on Cumulative EPS, measured on the grant date, is \$8,325,000 for Mr. Fehrman, \$2,850,000 for Mr. Mihalik, \$1,513,025 for Mr. Cannon, \$1,199,313 for Mr. Bertsen and \$1,400,000 for Ms. Knapp. The grant date fair value of the three-year performance shares and five-year performance shares that are based on Relative TSR is calculated using a Monte-Carlo model as of the date of grant, in accordance with FASB ASC Topic 718. The maximum amount payable for the 2025 performance shares that are based on Relative TSR, measured on the grant date is \$8,325,000 for Mr. Fehrman, \$2,850,000 for Mr. Mihalik, \$1,513,025 for Mr. Cannon, \$1,199,313 for Mr. Bertsen, and \$1,400,000 for Ms. Knapp. The values realized from the 2023-2025 performance shares are included in the Option Exercises and Stock Vested for 2025 table.
- The amounts shown in this column reflect annual incentive compensation paid for the year shown.
- The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and nonqualified defined benefit pension plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. See the Pension Benefits for 2025 table and related footnotes for additional information. See Note 8 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2025, for a discussion of the relevant assumptions. None of the named executive officers received preferential or above-market earnings on deferred compensation.
- Amounts shown in the All Other Compensation column for 2025 include: (a) Company matching contributions to the Company's Retirement Savings Plan; (b) Company matching contributions to the Company's Supplemental Retirement Savings Plan; (c) Company-paid relocation (including tax gross-ups of \$26,762 for Mr. Mihalik, \$83,991 for Mr. Cannon, and \$20,069 for Mr. Bertsen); (d) the incremental cost to the Company of personal use of Company-provided aircraft; (e) perquisites; and (f) vacation payout. The value of each item included in 2025 All Other Compensation column is listed in the following table:

Type	William J. Fehrman (7)	Trevor I. Mihalik	Douglas A. Cannon	Robert B. Bertsen	Alicia R. Knapp	Charles E. Zebula
Retirement Savings Plan Match	\$ 15,750	\$ 15,750	\$ 15,750	\$ 15,058	\$ 6,923	\$ 15,750
Supplemental Retirement Savings Plan Match	101,250	24,750	—	—	—	18,899
Relocation	—	78,529	241,757	78,893	20,000	—
Personal Use of Company Aircraft	140,507	—	—	—	—	—
Perquisites	22,781	23,590	5,121	8,184	—	8,991
Vacation Payout	—	—	—	—	—	90,276
Total	\$ 280,288	\$ 142,619	\$ 262,628	\$ 102,135	\$ 26,923	\$ 133,916

- Perquisites provided in 2025 included financial counseling and tax preparation services and, for Mr. Fehrman, \$632 as his allocated share of a group premium for travel accident insurance provided to all AEP board members. Executive officers may also have the occasional personal use of event tickets when such tickets are not being used for business purposes, however, there is no associated incremental cost to the Company. From time to time, executive officers also may receive customary gifts from third parties that sponsor events (subject to our policies on conflicts of interest).

Mr. Fehrman was a party to an Aircraft Time Sharing Agreement (Aircraft TSA) with the Company, which he used for his personal flights prior to July 22, 2025. As required under this Agreement, Mr. Fehrman reimbursed the Company for the full incremental cost of his personal use under his Aircraft TSA (but not the fixed cost), calculated in accordance with federal aviation regulations governing reimbursement for flight expenses to non-commercial aircraft operators. Accordingly, no value is shown for these personal flights in the Summary Compensation Table. If the aircraft flew empty to pick up or to return after dropping off Mr. Fehrman at a destination on a personal flight, the cost of the empty flight was included in the incremental cost for which Mr. Fehrman reimbursed the Company.

Effective July 22, 2025, the HR Committee adopted a policy that requires Mr. Fehrman to use a Company-provided aircraft for all business and personal air travel. In conjunction with this policy, Mr. Fehrman is no longer required to use his Aircraft TSA for personal trips or to reimburse the Company for its incremental cost. This change was made, in part, due to a comprehensive independent security assessment that recommended that Mr. Fehrman use a Company-provided aircraft for all air travel, including personal travel. See footnote 6 to the Summary Compensation Table for further information. Mr. Fehrman's spouse also accompanied him on the Company aircraft used for business travel, but there was no incremental cost to the Company for those trips.

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	William J. Fehrman, Chair of the Board and Chief Executive Officer	Columbus, Ohio	false	false
2	Robert B. Berntsen - Vice President and Secretary	Columbus, Ohio	false	false
3	Trevor I. Mihalik - Chief Financial Officer, Vice President	Columbus, Ohio	false	false
4	Cynthia G. Wiseman, President and Chief Operating Officer	Ashland, KY	false	false
5	Charles E. Zebula, Vice President and Chief Financial Officer	Columbus, Ohio	false	false
6	David M. Feinberg, Vice President and Secretary	Columbus, Ohio	false	false

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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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	PJM Interconnection LLC - Attachment H-14	ER17-405

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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)?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> 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	20251031-5359	10/31/2025	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
2	20250527-5221	05/27/2025	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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)
1	204-207	Electric Plant in Service	g	49
2	214	Electric Plant Held for Future Use	d	46
3	216	Construction Work in Progress	b	1
4	219	Accumulated Depreciation	b	21
5	310-311	Sales for Resale	k	1
6	320	Electric Operations & Maintenance Expense	b	5
7	320	Electric Operations & Maintenance Expense	b	25
8	320	Electric Operations & Maintenance Expense	b	31
9	321	Electric Operations & Maintenance Expense	b	93
10	323	Electric Operations & Maintenance Expense	b	185
11	336	Depreciation Expense	b	7
12	354	Distribution of Wages and Salaries	b	28

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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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.

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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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	3,764,104,296	3,614,362,254
3	Construction Work in Progress (107)	200	195,656,532	117,585,328
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,959,760,828	3,731,947,582
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	1,423,091,181	1,368,455,314
6	Net Utility Plant (Enter Total of line 4 less 5)		2,536,669,647	2,363,492,268
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)		2,536,669,647	2,363,492,268
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		502,366	502,366
19	(Less) Accum. Prov. for Depr. and Amort. (122)		186,244	179,574
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	2,388,745	
23	Noncurrent Portion of Allowances and Environmental Credits	228	8,306,722	8,349,737
24	Other Investments (124)		676,378	692,884
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)			
29	Special Funds (Non Major Only) (129)		44,875,201	38,324,925
30	Long-Term Portion of Derivative Assets (175)		529,079	436,823
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		57,092,247	48,127,161
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		1,050,496	839,453
36	Special Deposits (132-134)		634,401	4,196,423
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		9,162,101	15,412,437
41	Other Accounts Receivable (143)		37,136	163,583
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		51,776	605
43	Notes Receivable from Associated Companies (145)		16,416,328	
44	Accounts Receivable from Assoc. Companies (146)		18,080,530	18,072,922
45	Fuel Stock (151)	227	46,823,106	57,068,481
46	Fuel Stock Expenses Undistributed (152)	227	2,253,140	2,421,988
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	25,602,849	23,973,785
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	8,499,110	8,515,890
53	(Less) Noncurrent Portion of Allowances and Environmental Credits	228	8,306,722	8,349,737
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		2,338,044	2,241,790
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		3,409,799	2,956,857
61	Accrued Utility Revenues (173)		14,610,701	9,718,574
62	Miscellaneous Current and Accrued Assets (174)			
63	Derivative Instrument Assets (175)		9,555,427	5,691,344
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		529,079	436,823
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)		149,585,591	142,486,362
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		3,223,773	3,934,245
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	290,264,071	731,531,918
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,982,206	1,006,386
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	26,648,973	31,116,869
79	Def. Losses from Disposition of Utility PIt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		232,751	266,402
82	Accumulated Deferred Income Taxes (190)	234	82,093,446	82,133,216
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		404,445,220	849,989,036
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,147,792,706	3,404,094,827

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Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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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	50,450,000	50,450,000
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	527,119,552	526,069,518
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118	455,192,185	414,395,959
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)		1,032,761,737	990,915,477
17	LONG-TERM DEBT			
18	Bonds (221)	256		
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	1,065,000,000	1,215,000,000
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		525,812	592,937
24	Total Long-Term Debt (lines 18 through 23)		1,064,474,188	1,214,407,063
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		4,097,862	2,572,811
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		1,397,794	1,348,092
29	Accumulated Provision for Pensions and Benefits (228.3)		2,058,070	6,592,802
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		1,002,604	1,497,209
32	Long-Term Portion of Derivative Instrument Liabilities		67,137	6,782
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		92,105,834	88,832,997
35	Total Other Noncurrent Liabilities (lines 26 through 34)		100,729,301	100,850,693
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)			
38	Accounts Payable (232)		69,745,478	60,683,964
39	Notes Payable to Associated Companies (233)			183,212,284
40	Accounts Payable to Associated Companies (234)		55,425,881	49,420,756
41	Customer Deposits (235)		38,835,690	38,265,250
42	Taxes Accrued (236)	262	30,168,715.00	43,482,953.00
43	Interest Accrued (237)		9,799,912	10,447,249
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		2,554,303	2,568,209
48	Miscellaneous Current and Accrued Liabilities (242)		13,161,972	11,198,591
49	Obligations Under Capital Leases-Current (243)		981,603	350,482

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)		435,756	460,774
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		67,137	6,782
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)		221,042,173	400,083,730
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		100,102	99,104
57	Accumulated Deferred Investment Tax Credits (255)	266		
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	27,812,829	11,422,215
60	Other Regulatory Liabilities (254)	278	124,100,064	120,166,057
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	22,166,965	23,637,880
63	Accum. Deferred Income Taxes-Other Property (282)		297,325,094	287,551,685
64	Accum. Deferred Income Taxes-Other (283)		257,280,253	254,960,926
65	Total Deferred Credits (lines 56 through 64)		728,785,307	697,837,867
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,147,792,706	3,404,094,830

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Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	(2) <input type="checkbox"/> A Resubmission		

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas 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)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	764,751,475	706,582,368			764,751,475	706,582,368				
3	Operating Expenses											
4	Operation Expenses (401)	320	435,802,747	391,169,548			435,802,747	391,169,548				
5	Maintenance Expenses (402)	320	66,159,130	63,670,846			66,159,130	63,670,846				
6	Depreciation Expense (403)	336	120,883,595	102,688,187			120,883,595	102,688,187				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	1,875,227	1,209,506			1,875,227	1,209,506				
8	Amort. & Depl. of Utility Plant (404-405)	336		9,598,216				9,598,216				
9	Amort. of Utility Plant Acq. Adj. (406)	336	38,616	38,616			38,616	38,616				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		2,782,234	371,740			2,782,234	371,740				
13	(Less) Regulatory Credits (407.4)		(3,411,705)	(2,632,082)			(3,411,705)	(2,632,082)				
14	Taxes Other Than Income Taxes (408.1)	262	25,414,446	26,363,705			25,414,446	26,363,705				
15	Income Taxes - Federal (409.1)	262	(3,064,625)	3,175,965			(3,064,625)	3,175,965				
16	Income Taxes - Other (409.1)	262	150,752	338,204			150,752	338,204				

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	344,507,106	69,566,828			344,507,106	69,566,828				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	333,293,161	68,703,396			333,293,161	68,703,396				
19	Investment Tax Credit Adj. - Net (411.4)	266										
20	(Less) Gains from Disp. of Utility Plant (411.6)		16,506	14,518			16,506	14,518				
21	Losses from Disp. of Utility Plant (411.7)		(51)				(51)					
22	(Less) Gains from Disposition of Allowances (411.8)		7	180,729			7	180,729				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		2,326,748	1,425,167			2,326,748	1,425,167				
24.1	(Less) Gains from Disposition of Environmental Credits (411.11)											
24.2	Losses from Disposition of Environmental Credits (411.12)											
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24.2)		666,977,956	603,349,967			666,977,956	603,349,967				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		97,773,519	103,232,401			97,773,519	103,232,401				
28	Other Income and Deductions											
29	Other Income											
30	Nonutility Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)											
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)											
33	Revenues From Nonutility Operations (417)		325,601	330,190								
34	(Less) Expenses of Nonutility Operations (417.1)			645								
35	Nonoperating Rental Income (418)		(5,645)	(5,645)								
36	Equity in Earnings of Subsidiary Companies (418.1)	119										
37	Interest and Dividend Income (419)		1,362,884	1,002,524								
38	Allowance for Other Funds Used During Construction (419.1)		4,614,643	2,033,764								
39	Miscellaneous Nonoperating Income (421)		4,559,083	(8,446)								
40	Gain on Disposition of Property (421.1)		53									

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)
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		10,856,619	3,351,742								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)			174								
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		2,047,881	1,649,345								
46	Life Insurance (426.2)											
47	Penalties (426.3)		31,910	(6,524)								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		245,622	234,056								
49	Other Deductions (426.5)		7,317,805	5,442,535								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		9,643,218	7,319,586								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	84,219	75,358								
53	Income Taxes-Federal (409.2)	262	(1,594,880)	(1,326,337)								
54	Income Taxes-Other (409.2)	262	(151,155)	(70,099)								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272										
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272										
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(1,661,816)	(1,321,078)								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		2,875,218	(2,646,766)								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		65,772,626	69,504,133								
63	Amort. of Debt Disc. and Expense (428)		765,155	773,406								
64	Amortization of Loss on Reaquired Debt (428.1)		33,651	33,650								
65	(Less) Amort. of Premium on Debt-Credit (429)											
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)											
67	Interest on Debt to Assoc. Companies (430)		1,269,162	6,186,117								
68	Other Interest Expense (431)		(3,899,257)	(8,851,602)								

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)
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		4,088,827	3,921,790								
70	Net Interest Charges (Total of lines 62 thru 69)		59,852,510	63,723,914								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		40,796,226	36,861,721								
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)		40,796,226	36,861,721								

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Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	(2) <input type="checkbox"/> 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		414,395,959	377,534,238
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1	Adj to Retained Earnings			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		40,796,226	36,861,721
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	Common stock			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		455,192,185	414,395,959
39	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)		455,192,185	414,395,959
	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			
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		

STATEMENT OF CASH FLOWS

- 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.
- 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.
- 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.
- 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)	40,796,226	36,861,721
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	122,797,438	113,534,526
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Regulatory Debits and Credits (Net)	6,193,939	3,003,822
5.2	Mark-to-Market of Risk Management Contracts	(3,889,099)	(11,052,240)
8	Deferred Income Taxes (Net)	11,213,944	863,432
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	5,967,404	5,512,438
11	Net (Increase) Decrease in Inventory	8,785,160	22,428,695
12	Net (Increase) Decrease in Allowances and Environmental Credits Inventory	16,779	38,368
13	Net Increase (Decrease) in Payables and Accrued Expenses	923,808	2,272,539
14	Net (Increase) Decrease in Other Regulatory Assets	438,299,423	(16,271,627)
15	Net Increase (Decrease) in Other Regulatory Liabilities	3,878,846	(2,150,128)
16	(Less) Allowance for Other Funds Used During Construction	4,614,643	2,033,764
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):	(16,783,834)	(7,385,593)
18.2	Customer Deposits	570,440	238,379
18.3	Over/Under Recovered Fuel, Net	5,137,147	2,053,224
18.4	Impairment of Long Lived Assets	1,927,325	
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	621,220,303	147,913,792
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(279,225,889)	(194,559,376)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	(4,614,643)	(2,033,764)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):	(20,461)	
31.2	Acquired Assets		(1,383)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(274,631,706)	(192,526,995)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	342,445	197,559
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
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		

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)
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	Contribution in Aid of Construction Proceeds	1,718,239	
53.2	(Increase) Decrease in Other Special Deposits	62,198	(93,410)
53.3	Notes Receivable from Associated Companies	(16,416,328)	1,159,425
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(288,925,152)	(191,263,421)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	150,000,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
64.2	Long Term Issuances Costs	(17,558)	(76,627)
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Proceed on Capital leaseback	95,700	1,385
67.2	Notes Payable to Associated Companies		133,644,908
67.3	Capital Contributions from Parent	1,050,034	(701,806)
70	Cash Provided by Outside Sources (Total 61 thru 69)	151,128,176	132,867,860
72	Payments for Retirement of:		
73	Long-term Debt (b)	(300,000,000)	(90,000,000)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Notes Payable to Associated Companies - Retired	(183,212,284)	
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	(332,084,108)	42,867,860
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)	211,043	(481,769)
88	Cash and Cash Equivalents at Beginning of Period	839,453	1,321,222
90	Cash and Cash Equivalents at End of Period	1,050,496	839,453

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Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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NOTES TO FINANCIAL STATEMENTS

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

INDEX OF NOTES TO FINANCIAL STATEMENTS

	Glossary of Terms for Notes
1.	Organization and Summary of Significant Accounting Policies
2.	New Accounting Standards
3.	Rate Matters
4.	Effects of Regulation
5.	Commitments, Guarantees and Contingencies
6.	Benefit Plans
7.	Derivatives and Hedging
8.	Fair Value Measurements
9.	Income Taxes
10.	Leases
11.	Financing Activities
12.	Related Party Transactions
13.	Property, Plant and Equipment
14.	Revenue from Contracts with Customers
15.	FERC Order No.898

GLOSSARY OF TERMS FOR NOTES

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority-owned subsidiaries and affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KGPCo, KPCo, OPCo and WPCo.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPS	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AFUDC	Allowance for Equity Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
CCR	Coal Combustion Residual.
CPCN	Certificate of Public Convenience and Necessity.
CWIP	Construction Work in Progress.
ELG	Effluent Limitation Guidelines.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NOL	Net operating losses
NOLC	Net Operating Loss Carryforward.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.
OTC	Over-the-counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PLR	Private Letter Ruling.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TA	Transmission Agreement, effective November 2010, among APCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPS as agent.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	West Virginia Public Service Commission.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 161,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including KPCo, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

KPCo's rates are regulated by the FERC and the KPSC. The FERC also regulates KPCo's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over certain issuances and acquisitions of securities of public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires a nonregulated affiliate to bill an affiliated public utility company at no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The KPSC also regulates certain intercompany transactions under its affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets, wholesale power transactions and wholesale transmission operations and rates. KPCo's wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when KPCo negotiates and files a cost-based contract with the FERC or the FERC determines that KPCo has "market power" in the region where the transaction occurs. KPCo has entered into wholesale power supply contracts with various municipalities that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are true-up to actual costs annually.

The KPSC regulates all of the distribution operations and rates and retail transmission rates on a cost basis. The KPSC also regulates retail generation/power supply operations and rates.

In addition, the FERC regulates the TA, which allocates shared system costs and revenues among the utility subsidiaries that are parties to each agreement. The FERC also regulates the PCA. See Note 12 - Related Party Transactions for additional information.

Basis of Accounting

KPCo's accounting is subject to the requirements of the KPSC and the FERC. The financial statements have been prepared in accordance with the Uniform System of Accounts prescribed by the FERC. The principal differences from GAAP include:

- Accounting for subsidiaries on an equity basis.
- The classification of deferred fuel as noncurrent rather than current.
- The requirement to report deferred tax assets and liabilities separately rather than as a single amount.
- The classification of accrued taxes as a single amount rather than as assets and liabilities.
- The exclusion of current maturities of long-term debt from current liabilities.
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of finance lease payments as operating activities instead of financing activities.
- The classification of gains/losses from disposition of allowances as utility operating expenses rather than as operating revenues.
- The classification of PJM hourly activity for physical transactions as purchases and sales instead of net sales.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.
- The presentation of finance leased assets and their associated accumulated amortization as a single amount instead of as separate amounts.
- The classification of factored accounts receivable expense as a nonoperating expense instead of as an operating expense.
- The classification of certain nonoperating revenues as miscellaneous nonoperating income instead of as operating revenue.
- The classification of certain nonoperating expenses as miscellaneous nonoperating expense instead of as operating expense.
- The separate classification of income tax expense for operating and nonoperating activities instead of as a single income tax expense.
- The classification of gas procurement sales as a reduction of fuel expense rather than as revenue.
- The classification of unamortized loss on reacquired debt in deferred debits rather than in regulatory assets.
- The classification of deferred equity income in other deferred credits rather than in other non-current assets as securitized transition assets.
- The classification of amortization of deferred equity in operating revenues rather than in depreciation and amortization.
- The classification of certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.
- The classification of debt issuance costs as noncurrent assets instead of noncurrent liabilities.
- The classification of rents receivable as rents receivable instead of customer accounts receivable.
- The classification of Non-Service Cost Components of Net Periodic Benefit Cost as Operating Expense instead of Other Income (Expense).
- The classification of operating lease assets as Utility Plant rather than as a noncurrent asset.
- The presentation of obligations under finance and operating leases as a single amount in Obligations Under Capital Leases rather than as separate items.
- The classification of certain expenses in operating income rather than operating expenses.
- The classification of interest on regulated finance leases as operating expense instead of Other Income (Expense).
- The classification of cloud computing implementation costs as Utility Plant rather than as a noncurrent asset.
- The classification of depreciation of cloud computing as depreciation and amortization rather than as operating expenses.
- The classification of the make ready credits as other deferred credits rather than as other current liability.
- The classification of the reduced Excess ADIT regulatory liabilities resulting from the June 2025 FERC orders as non-operating income rather than as deferred income tax.
- The accounting for transactions with Kentucky Power Cost Recovery as a nonaffiliated company rather than consolidating the entity in accordance with the accounting guidance for "Variable Interest Entities."
- The removal of the original asset costs from Electric Plant in Service and the retirement of other property are classified as other property and investments rather than accumulated depreciation.
- The classification of gain on disposition of property and certain miscellaneous expenses as nonutility income rather than operating expenses.

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated electric public utility company, KPCo's financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," KPCo records regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, AROs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include Cash and Special Deposits on the balance sheets with original maturities of three months or less.

Supplementary Information

For the Years Ended December 31,

Cash was Paid for:

Interest

Noncash Acquisitions Under Finance Leases

As of December 31,

Construction Expenditures Included in Current and Accrued Liabilities

	2025	(in thousands)	2024
	\$	65,317	\$ 76,677
		661	126
		34,408	33,152

Inventory

Fossil fuel inventories and materials and supplies inventories are carried at average cost.

Accounts Receivable and Allowance for Uncollectible Accounts

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, KPCo accrues and recognizes, as Accrued Utility Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

Under an affiliated receivables sales arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit. AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, for KPCo. See "Securitized Accounts Receivables - AEP Credit" section of Note 11 for additional information.

Concentrations of Credit Risk and Significant Customers

KPCo had a significant customer which accounts for the following percentages of Total Revenues for the years ended December 31 and Accounts Receivable - Customers as of December 31:

	Significant Customer of KPCo: Marathon Petroleum Company	
	2025	2024
Percentage of Operating Revenues	15 %	15 %
Percentage of Customer Accounts Receivable	62 %	47 %

Management monitors credit levels and the financial condition of KPCo's customers on a continuous basis to minimize credit risk. The KPSC allows recovery in rates for a reasonable level of bad debt costs. Management believes adequate provision for credit loss has been made in the accompanying financial statements.

Property, Plant and Equipment

Electric utility property, plant and equipment are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of removal cost incurred and salvage received. These rates and the related lives are subject to periodic review.

The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in-service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed or is not probable, the cost of that asset shall be written down to its then current estimated fair value, with the change charged to expense, and the asset is removed from plant-in-service or CWIP.

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant.

Asset Retirement Obligations (ARO)

KPCo records ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal and for the retirement of certain ash disposal facilities. KPCo also records AROs related to the Federal EPA's revised CCR Rule. AROs are computed as the present value of the estimated costs associated with the future retirement of an asset and are recorded in the period in which the liability is incurred. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be decommissioned and the liabilities will be remediated as well as the inflation and discount rate, which may change significantly over time. The estimated costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. KPCo has identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since KPCo plans to use their facilities indefinitely. The retirement obligation would only be recognized if and when the Registrants abandon or cease the use of specific easements, which is not expected.

Valuation of Nonderivative Financial Instruments

The book values of Cash, Special Deposits, Notes Payable to Associated Companies and accounts receivable and accounts payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange-traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange-traded derivatives where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket-based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes.

Assets in the benefits trusts are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Investments classified as Other are valued using Net Asset Value as a practical expedient. Items classified as Other are primarily cash equivalent funds, common collective trusts, commingled funds, structured products, private equity, real estate and infrastructure investments. These investments do not have a readily determinable fair value or they contain redemption restrictions which may include the right to suspend redemptions under certain circumstances. Redemption restrictions may also prevent certain investments from being redeemed at the reporting date for the underlying value.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Operation Expenses when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the KPSC's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the KPSC. On a routine basis, the KPSC reviews and/or audits KPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. Changes in fuel costs, including purchased power, are reflected in rates in a timely manner through the FAC. A portion of margins from off-system sales are given to customers through the FAC.

Revenue Recognition

Regulatory Accounting

KPCo's financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses or alternative revenues recognized in accordance with the guidance for "Regulated Operations") and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching revenue with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, KPCo records them as assets on its balance sheets. Regulatory assets are reviewed for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, KPCo derecognizes that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

KPCo recognizes revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes such revenues on the statements of income as the performance obligations of delivering energy to customers are satisfied. Recognized revenues include unbilled as well as billed amounts. Wholesale transmission revenue is based on a FERC-approved formula rate filing made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under-recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. The annual true-up meets the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations". An estimated annual true-up is recorded by KPCo in the fourth quarter of each calendar year and a final annual true-up is recognized by KPCo in the second quarter of each calendar year following the filing of the annual FERC report.

Any portion of the true-up applicable to an affiliated company is recorded as Accounts Receivable from Associated Companies or Accounts Payable to Associated Companies on the balance sheets. Any portion of the true-ups applicable to third-parties is recorded as regulatory assets or regulatory liabilities on the balance sheets. See Note 14 - Revenue from Contracts with Customers for additional information.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

The power produced at KPCo's generation plants is sold to PJM. KPCo also purchases power from PJM to supply power to its customers. Generally, these power sales and purchases are reported on a net basis in revenues on the statements of income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded in Operation Expenses on the statements of income.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Operation Expenses on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's facts and circumstances. Derivative purchases elected normal used to serve accrual based obligations are recorded in Operation Expenses on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, KPCo records expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting. KPCo defers the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

KPCo engages in power marketing as a major power producer and participant in electricity markets. KPCo also engages in power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity risk management activities focused on markets where the AEP System owns assets and on adjacent markets. These activities include the purchase-and-sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

KPCo recognizes revenues from marketing and risk management transactions that are not derivatives as the performance obligation of delivering the commodity is satisfied. Expenses from marketing and risk management transactions that are not derivatives are also recognized upon delivery of the commodity.

KPCo uses MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. Unrealized MTM gains and losses are included on KPCo's balance sheets as Derivative Instrument Assets or Derivative Instrument Liabilities, as appropriate, and on KPCo's statements of income in Operating Revenues. Realized gains and losses on marketing and risk management transactions are included in revenues or expenses based on the transaction's facts and circumstances. However, in regulated jurisdictions subject to cost-based regulation, unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Certain qualifying marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). In the event KPCo designates a cash flow hedge, the cash flow hedge's gain or loss is initially recorded as a component of AOCI. When the forecasted transaction is realized and affects net income, KPCo subsequently reclassifies the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on the statements of income. See "Accounting for Cash Flow Hedging Strategies" section of Note 7.

Maintenance

Maintenance costs are expensed as incurred. If it becomes probable that KPCo will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues.

Income Taxes

KPCo uses the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost-of-service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

KPCo accounts for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." KPCo classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Penalties on the statements of income.

KPCo joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The benefit of current tax loss of the parent company (Parent Company Loss Benefit) to the AEP System subsidiaries is accounted for as an allocation through equity. The consolidated NOL of the AEP System is allocated for each company in the consolidated group with taxable loss. With the exception of the allocation of the consolidated AEP System NOL, the loss of the Parent and tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

Excise Taxes

As an agent for some state and local governments, KPCo collects from customers certain excise taxes levied by those state or local governments on customers. KPCo does not recognize these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt is refinanced, the reacquisition costs are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates.

Debt discounts, premiums and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations.

Pension and OPEB Plans

KPCo participates in an AEPSC sponsored qualified pension plan and two unfunded non-qualified pension plans. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and non-qualified pension plans. KPCo also participates in OPEB plans sponsored by AEPSC to provide health and life insurance benefits for retired employees. KPCo accounts for its participation in the AEPSC sponsored pension and OPEB plans using multiple-employer accounting. See Note 6 - Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan. The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	35 %
Fixed Income	49 %
Other Investments	15 %
Cash and Cash Equivalents	1 %

OPEB Plans Assets	Target
Equity	63 %
Fixed Income	36 %
Cash and Cash Equivalents	1 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies or certain commingled funds). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law.

For equity investments, the concentration limits are generally as follows:

- No security in excess of 5% of the outstanding class of equity of any one company.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, each investment manager's portfolio is compared to investment grade, diversified benchmark indices.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and opportunistic classifications.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships to invest across the private equity investment spectrum. The private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investments.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2025 and 2024, the fair value of securities on loan as part of the program was \$139 million and \$60 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2025 and 2024.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2025 through February 12, 2026, the date that KPCo's 2025 Annual Report was available to be issued, and has updated such evaluation for disclosure purposes through April 9, 2026. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

2. NEW ACCOUNTING STANDARDS

During the FASB's standard-setting process and upon issuance of final standards, management reviews the new accounting literature to determine its relevance, if any, to KPCo's business. The following standards will impact KPCo's financial statements.

ASU 2023-09 "Improvements to Income Tax Disclosures" (ASU 2023-09)

In December 2023, the FASB issued ASU 2023-09, to address investors' suggested enhancements to (a) better understand an entity's exposure to potential changes in jurisdictional tax legislation and the ensuing risks and opportunities, (b) assess income tax information that affects cash flow forecasts and capital allocation decisions and (c) identify potential opportunities to increase future cash flows.

The new standard requires an annual rate reconciliation disclosure of the following categories regardless of materiality: state and local income tax net of federal income tax effect, foreign tax effects, effect of changes in tax laws or rates enacted in the current period, effect of cross-border tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items and changes in unrecognized tax benefits.

The new standard also requires an annual disclosure of the amount of income taxes paid (net of refunds received) disaggregated by federal, state and foreign taxes and by individual jurisdictions that are equal to or greater than 5 percent of total income taxes paid. Disclosure of income (loss) from continuing operations before income tax expense (benefit) disaggregated between domestic and foreign jurisdictions and income tax expense (benefit) from continuing operations disaggregated by federal, state and foreign jurisdictions is required.

The new standard removes the requirement to disclose the cumulative amount of each type of temporary difference when a deferred tax liability is not recognized because of the exceptions to comprehensive recognition of deferred taxes related to subsidiaries and corporate joint ventures.

Management adopted ASU 2023-09 and its related implementation guidance effective January 1, 2025 for the annual reporting period and applied the amendments retrospectively to all prior periods presented in the annual consolidated financial statements. The adoption of the new standard did not impact the results of operations, statements of financial position or cash flows. See Note 9 - Income Taxes for additional information.

ASU 2025-06 "Intangibles—Goodwill and Other—Internal-Use Software" (ASU 2025-06)

In September 2025, the FASB issued ASU 2025-06, the intent of which is to modernize the cost capitalization threshold for internal-use software development costs by removing all references to software project development stages and providing new guidance on how to evaluate whether the probable-to-complete recognition threshold has been met for the commencement of capitalization of eligible costs.

The amendments in the new standard may be applied on either a retrospective, prospective or modified prospective basis for public business entities for fiscal years beginning after December 15, 2027 with early adoption permitted. Management elected to early adopt this standard prospectively beginning on January 1, 2026. The adoption of the new standard is not expected to have a material impact on the results of operations, statements of financial position or cash flows.

3. RATE MATTERS

KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. Rate matters can have a material impact on net income, cash flows and possibly financial condition. KPCo's recent significant rate orders and pending rate filings are addressed in this note.

Investigation of the Service, Rates and Facilities of KPCo

In June 2023, the KPSC issued an order directing KPCo to show cause why it should not be subject to Kentucky statutory remedies, including fines and penalties, for failure to provide adequate service in its service territory. The KPSC's show cause order did not make any determination regarding the adequacy of KPCo's service. In July 2023, KPCo filed a response to the show cause order demonstrating that it has provided adequate service. In December 2023 and February 2024, KPCo and certain intervenors filed testimony with the KPSC. A hearing with the KPSC was previously scheduled to occur in June 2024. The hearing was postponed and has not yet been rescheduled. If any fines or penalties are levied against KPCo relating to the show cause order, it could reduce future net income and cash flows and impact financial condition.

2023 Kentucky Base Rate and Securitization Case

In June 2023, KPCo filed a request with the KPSC for a \$93.9 million net annual increase in base rates based upon a proposed 9.9% ROE with the increase to be implemented no earlier than January 2024. In conjunction with its June 2023 filing, KPCo further requested to finance, through the issuance of securitization bonds, approximately \$471.2 million of regulatory assets. KPCo's proposal did not address the disposition of its 50% interest in Mitchell Plant, which will be addressed in the future. See "Mitchell Plant Filing for Certificate of Public Convenience and Necessity" section below for additional information.

In November 2023, KPCo filed an uncontested settlement agreement with the KPSC, that included an annual base rate increase of \$74.7 million, based upon a 9.75% ROE. Settlement parties agreed that the KPSC should approve KPCo's securitization request, and that the approximately \$471.2 million of regulatory assets requested for securitization are comprised of prudently incurred costs.

In January 2024, the KPSC issued an order modifying the November 2023 uncontested settlement agreement and approving an annual base rate increase of \$60 million based upon a 9.75% ROE effective with billing cycles starting mid-January 2024. The order reduced KPCo's base rate revenue requirement by \$14.2 million to allow recovery of actual test year PJM transmission costs instead of KPCo's requested annual level of costs based on PJM 2023 projected transmission revenue requirements. In February 2024, KPCo filed an appeal with the Commonwealth of Kentucky Franklin Circuit Court (Circuit Court), challenging among other aspects of the order, the \$14.2 million base rate revenue requirement reduction. In January 2025, the Circuit Court issued an order agreeing with KPCo's appeal and remanded this issue back to the KPSC with instructions to enter an order, within 30 days, which includes setting rates to allow KPCo to recover the \$14.2 million of annual PJM transmission costs effective upon KPCo's January 2024 implementation of updated base rates. In March 2025, the KPSC issued a rehearing order that approved rates for the prospective collection of test year PJM transmission costs beginning in February 2025 but denied KPCo's request to defer and recover the historical PJM transmission costs of approximately \$15.7 million incurred from January 2024 through the February 2025 update in base rates. In April 2025, KPCo filed an appeal with the Circuit Court for a motion to enforce in response to the KPSC's denial to recover PJM transmission costs incurred from January 2024 through the implementation of new rates. In September 2025, the Circuit Court issued an order granting KPCo's motion to enforce. In October 2025, the KPSC issued an order approving recovery of the \$15.7 million of PJM transmission costs, with debt and equity carrying charges starting September 15, 2025 on the remaining PJM transmission costs to be recovered, through a rider. The rider was effective with the first billing cycle in November 2025 and will be in place for 22 months.

In June 2025, KPCo issued \$477.7 million of securitization bonds to recover \$500.2 million of regulatory assets, including \$311.3 million of plant retirement costs, \$78.8 million of deferred storm costs related to 2020, 2021, 2022 and 2023 major storms, \$55.6 million of under-recovered purchased power rider costs, \$51.3 million of deferred purchased power expenses and \$3.1 million of issuance-related expenses, including KPSC advisor expenses. The net bond proceeds of the \$477.7 million also included \$6.3 million of non-utility issuance costs and a \$28.8 million offset for net present value of return on accumulated deferred income taxes related to KPCo's securitized plant retirement costs as ordered by the KPSC.

Mitchell Plant Filing for Certificate of Public Convenience and Necessity

KPCo and WPCo each own a 50% undivided interest in the 1,560 MW coal-fired Mitchell Plant. In July 2021, the KPSC rejected KPCo's ELG compliance plan for KPCo's 50% ownership share of ELG investments at the Mitchell Plant that would allow KPCo to take capacity and energy to serve customers beyond December 31, 2028. As a result of this order, and pursuant to September 2022 resolutions under the existing Mitchell Plant Operating Agreement, WPCo funded 100% of the Mitchell Plant ELG investments that have been placed in service. In addition, WPCo also paid for a greater than 50% share of certain non-ELG capital investments made at Mitchell Plant which will continue to be used in the operation of Mitchell Plant beyond 2028.

In June 2025, KPCo filed a request with the KPSC for a CPCN to make investments necessary to reflect: (a) a 50% share of the Mitchell Plant ELG Project and (b) a 50% share of non-ELG capital investments. KPSC approval of these investments would allow KPCo to continue taking a 50% share of energy and capacity from the Mitchell Plant to serve KPCo customers beyond December 31, 2028. KPCo proposed to recover the estimated \$78 million investment in the ELG Project through KPCo's existing Environmental Surcharge and requested recovery of an estimated \$60 million of Mitchell Plant non-ELG capital investments through its 2025 Kentucky Base Rate Case filing. See "2025 Kentucky Base Rate Case" section below for additional information.

In November 2025, KPCo and an intervening party submitted a settlement agreement that recommended the approval of KPCo's proposed Mitchell Plant CPCN and use of KPCo's Environmental Surcharge to recover Mitchell Plant ELG project costs through 2040. The settlement agreement further recommended granting KPCo authority to defer the depreciation expense and carrying costs associated with Mitchell Plant non-ELG capital investments to a regulatory asset until it can be reflected in rates. The recovery mechanism for Mitchell Plant non-ELG capital investments will be addressed in KPCo's 2025 Kentucky Base Rate Case filing. See "2025 Kentucky Base Rate Case" section below for additional information.

In December 2025, the KPSC issued an order approving the settlement agreement, the Mitchell Plant CPCN and recovery of ELG capital investments through the Environmental Surcharge. The KPSC's order imposes annual reporting requirements to review capital investment costs at the Mitchell Plant.

To operate in accordance with KPSC and WVPSC directives related to Mitchell Plant ELG investments, KPCo and WPCo expect to utilize existing authority under the Mitchell Plant Operating Agreement to revise billing procedures resulting in equal allocation of costs. In February 2026, WPCo requested that the WVPSC grant any additional authorizations necessary to enable WPCo to reflect the holdings and impact of the December 2025 KPSC order or make a determination that no such authorizations are required. As of December 31, 2025, the net book value of KPCo's share of the Mitchell Plant, before cost of removal and including CWIP and inventory, and prior to the effect of revised billing procedures expected under the Mitchell Plant Operating Agreement to comply with the KPSC's December 2025 order, was \$523.1 million.

2025 Kentucky Base Rate Case

In August 2025, KPCo filed a request with the KPSC for a \$95.6 million net annual increase in base rates based upon a proposed 10% ROE and a proposed capital structure of 53.9% debt and 46.1% common equity, to be implemented no earlier than March 2026. Among other changes, the filing proposed a \$10 million increase in PJM transmission costs, an \$8.7 million increase due to load loss and a \$6 million increase in depreciation rates.

The proposed annual rate increase also included a \$20.3 million annual revenue requirement related to KPCo's investment in the Mitchell Plant. See "Mitchell Plant Filing for Certificate of Public Convenience and Necessity" section above for additional information. As part of this filing, KPCo requested a new generation rider to recover the remaining net book value of KPCo's non-environmental investment in the Mitchell Plant that has historically been recovered through base rates. If the generation rider is approved, the \$20.3 million would be removed from the requested revenue requirement increase and would be collected through the rider. Additionally, KPCo is pursuing securitization legislation that would allow KPCo to securitize the remaining net book value of the Mitchell Plant. If the securitization of the remaining Mitchell Plant net book value is successful, collection of costs through the generation rider would cease.

In January 2026, KPCo and certain intervening parties submitted a settlement agreement with the KPSC proposing a \$77.4 million annual increase in Kentucky retail rates, including: (a) a \$58.7 million annual increase in KPCo base rates based on a 9.8% authorized ROE and a capital structure of 53.9% debt and 46.1% common equity, and (b) a new generation rider with a first year revenue requirement of \$18.7 million based on a 9.7% authorized ROE to recover non-environmental plant investments at Mitchell Plant and all incremental capital investments after May 31, 2025 at both Mitchell Plant and Big Sandy Plant. Capital and other operation and maintenance expenses related to any new generating assets also will be eligible for inclusion in the Generation Rider, subject to KPSC approval. The settlement revenue requirement will be reduced by \$25 million in the first year and \$15 million in the second year through a new rider that returns certain unprotected deferred tax expenses in customer rates on a temporary basis, and then beginning in the third year, collects the deferred tax expense amounts from customers over the estimated time period that taxes are due to the IRS. The settlement agreement also proposes: (a) approval to defer all storm other operation and maintenance expenses above or below the level included in base rates, and (b) approval to defer vegetation management costs above or below the level included in base rates, capped at a total of \$45 million in 2026 and \$52 million in 2027. Consistent with the KPSC order in KPCo's 2023 Kentucky Base Rate Case filing, the settlement agreement also provides that KPCo's proposal to include a stand-alone NOLC deferred tax asset in rate base will be addressed in a future proceeding upon KPCo's receipt of a PLR or other guidance from the IRS. A hearing was held in January 2026.

In February 2026, an intervenor filed a brief recommending that the KPSC should deny the requested rate increase. The intervenor also stated that if the KPSC were to approve a rate increase, the settlement agreement should be modified to allow a \$39.6 million annual increase in KPCo base rates based on an 8.9% ROE and a capital structure of 55% debt and 45% common equity. Additionally, the brief: (a) suggests increasing the amount of the first and second year revenue requirement reductions to \$49 million and \$28 million, respectively, relating to the new rider proposed in the settlement agreement that returns certain unprotected deferred tax expenses in customer rates on a temporary basis, (b) proposes that KPCo should be restricted from filing to recover \$60.4 million of Mitchell Plant non-ELG capital investments, expected to result from the approved settlement agreement in the 2025 Mitchell Plant CPCN proceeding, for a minimum of three years (see "Mitchell Plant Filing for Certificate of Public Convenience and Necessity" section above for additional information) and (c) recommends that the KPSC order an independent management audit to engage outside experts to determine how Kentucky Power can improve its service and rates.

A KPSC order is expected to be issued in the first quarter of 2026 with implementation of KPCo retail rates in March 2026. If any costs included in this filing are not approved for recovery, it could reduce future net income and cash flows and impact financial condition.

Transmission Agreement Cost Allocation Complaint

In March 2025, the KPSC and the Attorney General of Kentucky filed a complaint at the FERC against AEPSC and the AEP East Companies challenging the manner in which costs are allocated for local transmission projects pursuant to the TA. The complaint contends that certain costs allocated to KPCo are unjust, unreasonable and provide no benefit to KPCo customers. The relief requested in the complaint includes requiring a revision to the TA so that the costs for local transmission projects remain exclusively with the retail distribution service territory where the project is located unless a specific project is granted approval to establish a different cost allocation by the state commissions. Various parties have filed comments and motions to intervene. In May 2025, AEP filed a motion to dismiss and answered the complaint. In November 2025, the FERC issued an order denying the KPSC and Attorney General of Kentucky complaint. In December 2025, the KPSC and Attorney General of Kentucky requested a rehearing of the November order denying the complaint. In January 2026, the FERC issued a notice of denial of the request for rehearing by operation of law, providing the FERC with additional time to consider and decide on the merits of the request. In February 2026, the KPSC and Attorney General of Kentucky filed a petition for review of the FERC's orders in this matter with the United States Court of Appeals for the Sixth Circuit. If the FERC orders a change in the way costs are allocated pursuant to the TA it could impact future net income, cash flows and financial condition.

4. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31,		Remaining Recovery Period
	2025	2024	
	(in thousands)		
Regulatory assets pending final regulatory approval:			
<u>Regulatory Assets Currently Not Earning a Return</u>			
Storm-Related Costs (a)	\$ 21,663	\$ 89,543	
Other Regulatory Assets Pending Final Regulatory Approval	3,383	3,840	
Total Regulatory Assets Pending Final Regulatory Approval	25,046	93,383	
Regulatory assets approved for recovery:			
<u>Regulatory Assets Currently Earning a Return</u>			
Transmission Costs Deferral	13,852	—	2 years
Plant Retirement Costs	—	180,907	
Plant Retirement Costs - Asset Retirement Obligation Costs	294	110,510	
Kentucky Deferred Purchased Power Expenses	—	45,011	
Other Regulatory Assets Approved for Recovery	299	3,965	various
Total Regulatory Assets Currently Earning a Return	14,445	340,393	
<u>Regulatory Assets Currently Not Earning a Return</u>			
Income Tax Assets	145,987	146,057	(b)
Fuel and Purchased Power Rider	—	57,373	
Securitization Costs	27,781	—	20 years
Pension and OPEB Funded Status	7,601	13,726	12 years
Under-recovered Fuel Costs	3,497	8,635	1 year
Plant Retirement Costs - Asset Retirement Obligation Costs	54,735	52,294	15 years
Other Regulatory Assets Approved for Recovery	11,172	19,671	various
Total Regulatory Assets Currently Not Earning a Return	250,773	297,756	
Total Regulatory Assets Approved for Recovery	265,218	638,149	
Total FERC Account 182.3 Regulatory Assets	\$ 290,264	\$ 731,532	

(a) KPCo will seek recovery of these costs in the next base rate case.

(b) Recovered over the period for which the related deferred income taxes reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets.

Regulatory Liabilities:	December 31,		Remaining Refund Period
	2025	2024	
	(in thousands)		
Regulatory liabilities pending final regulatory determination:			
<u>Regulatory Liabilities Currently Not Paying a Return</u>			
Securitization Bond Deferral	\$ 255	\$ —	
Total Regulatory Liabilities Pending Final Regulatory Determination	<u>255</u>	<u>—</u>	
Total Regulatory Liabilities Pending Final Regulatory Determination	<u>255</u>	<u>—</u>	
Regulatory liabilities approved for payment:			
<u>Regulatory Liabilities Currently Paying a Return</u>			
Income Taxes Liabilities (a)	110,876	114,951	(b)
Total Regulatory Liabilities Currently Paying a Return	<u>110,876</u>	<u>114,951</u>	
<u>Regulatory Liabilities Currently Not Paying a Return</u>			
Unrealized Gain on Forward Commitments	4,593	844	3 years
Purchased Power Adjustment Rider	2,040	—	2 years
Other Regulatory Liabilities Approved for Payment	6,336	4,371	various
Total Regulatory Liabilities Currently Not Paying a Return	<u>12,969</u>	<u>5,215</u>	
Total Regulatory Liabilities Approved for Payment	<u>123,845</u>	<u>120,166</u>	
Total FERC Account 254 Regulatory Liabilities	<u>\$ 124,100</u>	<u>\$ 120,166</u>	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.

(b) Recovered over the period for which the related deferred income taxes reverse, which is generally based on the expected life for the underlying assets. Excess ADIT associated with certain depreciable property is recovered over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were \$1.7 million and \$2.8 million for the years ended December 31, 2025 and 2024, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2025 is to be refunded over 3 years.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against KPCo cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

COMMITMENTS

KPCo has substantial commitments to support its business. KPCo purchases fuel, energy and capacity contracts as part of its normal course of business. Certain contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following table summarizes KPCo's actual contractual commitments as of December 31, 2025:

Contractual Commitments	Less Than				After 5 Years	Total
	1 Year	2-3 Years	4-5 Years	5 Years		
	(in thousands)					
Fuel Purchase Contracts (a)	\$ 5,993	\$ 12,002	\$ 11,985	\$ 2,479	\$ 32,459	

(a) Represents contractual commitments to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third-parties unless specified below.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2025, there were no material liabilities recorded for any indemnifications.

AEPS conducts power purchase-and-sale activity on behalf of APCo, I&M, KPCo and WPCo, who are jointly and severally liable for activity conducted on their behalf.

ENVIRONMENTAL CONTINGENCIES

Federal EPA's Revised CCR Rule

In April 2024, the Federal EPA finalized revisions to the CCR Rule (Legacy CCR Rule) to expand the scope of the rule to include inactive impoundments at inactive facilities (legacy CCR surface impoundments) as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land (CCR management units). The Federal EPA is requiring that owners and operators of legacy surface impoundments comply with all of the Legacy CCR Rule requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner design criteria. The rule establishes compliance deadlines for legacy surface impoundments to meet regulatory requirements, including a requirement to initiate closure within five years after the effective date of the final rule. The rule requires evaluations to be completed at both active facilities and inactive facilities with one or more legacy surface impoundments. Closure may be accomplished by applying an impermeable cover system over the CCR material (closure in place) or the CCR material may be excavated and placed in a compliant landfill (closure by removal). Groundwater monitoring and other analysis over the next three years will provide additional information on the planned closure method. KPCo evaluated the applicability of the rule to current and former plant sites and recorded incremental ARO in the second quarter of 2024, as shown in the table below, based on initial cost estimates primarily reflecting compliance with the rule through closure in place and future groundwater monitoring requirements pursuant to the Legacy CCR Rule.

Increase in ARO	Increase in Generation Property (a)	Increase in Regulatory Assets (b)
(in thousands)		
\$ 68,049	\$ 21,884	\$ 46,165

(a) ARO is related to a legacy CCR surface impoundment or CCR management unit at an operating generation facility.

(b) ARO is related to a legacy CCR surface impoundment or CCR management unit at a retired generation facility and recognition of a regulatory asset in accordance with the accounting guidance for "Regulated Operations" is supported.

As further groundwater monitoring and other analysis is performed, management expects to refine the assumptions and underlying cost estimates used in recording the ARO. These refinements may include, but are not limited to, changes in the expected method of closure, changes in estimated quantities of CCR at each site, the identification of new CCR management units, among other items. These future changes could have a material impact on the ARO and materially reduce future net income and cash flows and further impact financial condition.

AEP will seek cost recovery through regulated rates, including proposal of new regulatory mechanisms for cost recovery where existing mechanisms are not applicable. The rule could have an additional, material adverse impact on net income, cash flows and financial condition if AEP cannot ultimately recover these additional costs of compliance. Several parties, including AEP and one of its trade associations, have filed petitions for review of the Legacy CCR Rule with the U.S. Court of Appeals for the District of Columbia Circuit. The litigation is being held in abeyance. In December 2025, the Federal EPA informed the court that it anticipates publishing a proposed rule in January 2026 that should be finalized by October 2026, which will revise certain provisions of the Legacy CCR Rule for both legacy CCR surface impoundments and CCR management units. The Federal EPA further noted that it has been working to obtain technical information to inform its reconsideration and develop a record to support a proposal. Reconsideration of the rule will require a new round of notice-and-comment rulemaking.

In November 2025, the Federal EPA proposed to extend by three years the compliance deadline applicable to certain facilities operating pursuant to alternative closure deadlines for unlined surface impoundments greater than 40 acres. In February 2026, the Federal EPA finalized a rule that provides additional time to meet facility evaluation requirements for identifying CCR management units and to comply with groundwater monitoring provisions. Additionally, this rule makes conforming changes to the remaining CCR management units compliance deadlines. Management cannot predict the outcome of the litigation or any further actions by the Federal EPA related to the rule.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag and sludge. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and non-hazardous materials. KPCo currently incurs costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2025, there is one site for which KPCo has received an information request which could lead to a Potentially Responsible Party designation. In the instance where KPCo has been named a defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named for each site and several of the parties are financially sound enterprises. As of December 31, 2025, management's estimates do not anticipate material clean-up costs for the identified site.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

KPCo maintains insurance coverage normal and customary for an electric utility, subject to various deductibles. KPCo also maintains property and casualty insurance that may cover certain physical damage or third-party injuries caused by cyber security incidents. Insurance coverage includes all risks of physical loss or damage to assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third-parties and are in excess of KPCo's retentions. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cyber security incident or extreme weather or wildfire related liabilities. Future losses or liabilities, if they occur, which are not completely insured, unless recovered through the rate-making process, could reduce future net income and cash flows and impact financial condition.

6. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Fair Value Measurements of Assets and Liabilities" and "Investments Held in Trust for Future Liabilities" sections of Note 1.

KPCo participates in an AEPSC sponsored qualified pension plan and an unfunded non-qualified pension plan. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and non-qualified pension plans. KPCo also participates in OPEB plans sponsored by AEPSC to provide health and life insurance benefits for retired employees.

KPCo recognizes its funded status associated with defined benefit pension and OPEB plans on its balance sheets. Disclosures about the plans are required by the "Compensation - Retirement Benefits" accounting guidance. KPCo recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status and recognizes, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. KPCo records a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for rate-making purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions used in the measurement of benefit obligations are shown in the following table:

Assumptions	Pension Plans		OPEB	
	December 31,			
	2025	2024	2025	2024
Discount Rate	5.50 %	5.65 %	5.50 %	5.60 %
Interest Crediting Rate	4.40 %	4.55 %	NA	NA
Rate of Compensation Increase	4.60 % (a)	5.75 % (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.
NA Not applicable.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2025, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with an average increase of 4.6%.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions used in the measurement of benefit costs are shown in the following table:

Assumptions	Pension Plans		OPEB	
	Year Ended December 31,			
	2025	2024	2025	2024
Discount Rate	5.65 %	5.20 %	5.60 %	5.15 %
Interest Crediting Rate	4.55 %	4.05 %	NA	NA
Expected Return on Plan Assets	7.00 %	7.30 %	6.50 %	6.75 %
Rate of Compensation Increase	6.00 % (a)	5.25 % (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.
NA Not applicable.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, third-party forecasts and current prospects for economic growth.

The health care trend rate assumptions used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	December 31,	
	2025	2024
Initial	6.00 %	6.50 %
Ultimate	4.50 %	4.50 %
Year Ultimate Reached	2031	2029

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. The plans are monitored to control security diversification and compliance with the investment policy. As of December 31, 2025, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status

For the year ended December 31, 2025, the pension plans had an actuarial loss primarily due to a decrease in discount rate and an unfavorable demographic experience (updated census data on January 1, 2025). For the year ended December 31, 2025, the OPEB plans had an actuarial gain primarily due to updated per capita cost and Employer Group Waiver Plan assumptions. These gains were partially offset by updated discount and trend rates. For the year ended December 31, 2024, the pension plans had an actuarial loss primarily due to an unfavorable demographic experience (updated census data on January 1, 2024), specifically intra-company participant transfer activity from other AEP registrants. These losses were partially offset by the increase in the discount rate. For the year ended December 31, 2024, the OPEB plans had an actuarial gain primarily due to updated per capita cost assumptions and increases in discount rates. These gains were partially offset by the loss for intra-company participant transfer activity from other AEP registrants. The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		OPEB	
	2025	2024	2025	2024
	(in thousands)			
Change in Benefit Obligation				
Benefit Obligation as of January 1,	\$ 114,278	\$ 92,174	\$ 19,936	\$ 23,129
Service Cost	1,551	1,604	47	56
Interest Cost	6,250	6,127	1,041	1,373
Actuarial (Gain) Loss	1,853	28,735	(1,997)	(2,491)
Settlements	—	(6,023)	—	—
Special/Contractual Termination Benefits	—	—	—	94
Benefit Payments	(9,911)	(8,339)	(3,877)	(3,996)
Participant Contributions	—	—	1,764	1,765
Medicare Subsidy	—	—	5	6
Benefit Obligation as of December 31,	\$ 114,021	\$ 114,278	\$ 16,919	\$ 19,936
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	\$ 109,278	\$ 87,421	\$ 58,261	\$ 47,872
Actual Gain on Plan Assets	12,075	36,219	5,646	12,618
Company Contributions	2,104	—	—	2
Participant Contributions	—	—	1,764	1,765
Settlements	—	(6,023)	—	—
Benefit Payments	(9,911)	(8,339)	(3,877)	(3,996)
Fair Value of Plan Assets as of December 31,	\$ 113,546	\$ 109,278	\$ 61,794	\$ 58,261
Funded (Underfunded) Status as of December 31,	\$ (475)	\$ (5,000)	\$ 44,875	\$ 38,325

Amounts Recognized on the Balance Sheets

	Pension Plans		OPEB	
	2025	2024	2025	2024
	December 31, (in thousands)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	\$ —	\$ —	\$ 44,875	\$ 38,325
Other Current Liabilities – Accrued Short-term Benefit Liability	(1)	—	—	—
Employee Benefits and Pension Obligations – Accrued Long-Term Benefit Liability	(474)	(5,000)	—	—
Funded (Underfunded) Status	\$ (475)	\$ (5,000)	\$ 44,875	\$ 38,325

Amounts Included in Regulatory Assets, Deferred Income Taxes

The following tables show the components of the plans included in regulatory assets and Accumulated Deferred Income Taxes and the items attributable to the change in these components:

Components	Pension Plans		OPEB	
	2025	2024	2025	2024
	December 31, (in thousands)			
Net Actuarial (Gain) Loss	\$ 16,717	\$ 18,945	\$ (8,775)	\$ 4,812
Prior Service Credit	—	—	(341)	407
Recorded as	\$ 16,717	\$ 18,945	\$ (9,116)	\$ 5,219

Components	Pension Plans		OPEB	
	2025	2024	2025	2024
	December 31, (in thousands)			
Actuarial (Gain) Loss During the Year	\$ (1,780)	\$ 1,939	\$ (3,963)	\$ (11,256)
Amortization of Actuarial Loss	(448)	(93)	—	(118)
Amortization of Prior Service Credit	—	—	66	374
Amounts Recognized Due to Settlement	—	(1,689)	—	—
Transfers - Prior Service Cost	—	—	—	(1)
Transfers - (Gain)/loss	—	—	—	1
Change for the Year Ended December 31,	\$ (2,228)	\$ 157	\$ (3,897)	\$ (11,000)

Determination of Pension Expense

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

Pension and OPEB Assets

The fair value tables within Pension and OPEB Assets present the classification of assets for AEP within the fair value hierarchy. All Level 1, 2, 3 and Other amounts can be allocated to KPCo using the percentages below:

Pension Plan		OPEB	
December 31,			
2025	2024	2025	2024
3.0 %	3.0 %	3.1 %	3.3 %

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2025:

Asset Class	Level 1	Level 2	Level 3 (in millions)	Other	Total	Year End Allocation
Equities (a):						
Domestic	\$ 109	\$ —	\$ —	\$ —	\$ 109	2.9 %
International	68	—	—	—	68	1.8 %
Common Collective Trusts (b)	228	—	—	901	1,129	30.0 %
Subtotal – Equities	405	—	—	901	1,306	34.7 %
Fixed Income (a):						
United States Government and Agency Securities	—	1,060	—	—	1,060	28.2 %
Corporate Debt	—	627	—	—	627	16.7 %
Foreign Debt	—	110	—	—	110	2.9 %
State and Local Government	—	21	—	—	21	0.6 %
Other – Asset Backed	—	5	—	—	5	0.1 %
Subtotal – Fixed Income	—	1,823	—	—	1,823	48.5 %
Infrastructure (b)	—	—	—	114	114	3.0 %
Real Estate (b)	—	—	—	221	221	5.9 %
Alternative Investments (b)	—	—	—	218	218	5.8 %
Cash and Cash Equivalents (b)	—	18	—	29	47	1.3 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	30	30	0.8 %
Total	\$ 405	\$ 1,841	\$ —	\$ 1,513	\$ 3,759	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.

(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.

(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2025:

Asset Class	Level 1	Level 2	Level 3 (in millions)	Other	Total	Year End Allocation
Equities:						
Domestic	\$ 643	\$ —	\$ —	\$ —	\$ 643	32.5 %
International	241	—	—	—	241	12.2 %
Common Collective Trusts (a)	85	—	—	287	372	18.8 %
Subtotal – Equities	969	—	—	287	1,256	63.5 %
Fixed Income:						
United States Government and Agency Securities	—	265	—	—	265	13.4 %
Corporate Debt	—	141	—	—	141	7.1 %
Foreign Debt	—	26	—	—	26	1.3 %
State and Local Government	84	4	—	—	88	4.4 %
Other – Asset Backed	—	2	—	—	2	0.1 %
Subtotal – Fixed Income	84	438	—	—	522	26.3 %
Trust Owned Life Insurance:						
International Equities	—	30	—	—	30	1.5 %
United States Bonds	—	110	—	—	110	5.6 %
Subtotal – Trust Owned Life Insurance	—	140	—	—	140	7.1 %
Cash and Cash Equivalents (a)	28	—	—	—	28	1.4 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	34	34	1.7 %
Total	\$ 1,081	\$ 578	\$ —	\$ 321	\$ 1,980	100.0 %

(a) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.

(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2024:

Asset Class	Level 1	Level 2	Level 3 (in millions)	Other	Total	Year End Allocation
Equities (a):						
Domestic	\$ 327	\$ —	\$ —	\$ —	\$ 327	8.9 %
International	290	—	—	—	290	7.9 %
Common Collective Trusts (b)	176	—	—	473	649	17.7 %
Subtotal – Equities	793	—	—	473	1,266	34.5 %
Fixed Income (a):						
United States Government and Agency Securities	(2)	866	—	—	864	23.6 %
Corporate Debt	—	719	—	—	719	19.6 %
Foreign Debt	—	136	—	—	136	3.7 %
State and Local Government	—	26	—	—	26	0.7 %
Other – Asset Backed	—	1	—	—	1	— %
Subtotal – Fixed Income	(2)	1,748	—	—	1,746	47.6 %
Infrastructure (b)	—	—	—	113	113	3.1 %
Real Estate (b)	—	—	—	228	228	6.2 %
Alternative Investments (b)	—	—	—	224	224	6.1 %
Cash and Cash Equivalents (b)	—	41	—	27	68	1.9 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	21	21	0.6 %
Total	\$ 791	\$ 1,789	\$ —	\$ 1,086	\$ 3,666	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.

(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.

(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2024:

Asset Class	Level 1	Level 2	Level 3		Other	Total	Year End Allocation
			(in millions)				
Equities:							
Domestic	\$ 617	\$ —	\$ —	\$ —	\$ —	\$ 617	34.7 %
International	267	—	—	—	—	267	15.0 %
Common Collective Trusts (a)	64	—	—	—	130	194	10.9 %
Subtotal – Equities	948	—	—	—	130	1,078	60.6 %
Fixed Income:							
Common Collective Trust – Debt (a)	—	—	—	—	133	133	7.5 %
United States Government and Agency Securities	(1)	158	—	—	—	157	8.9 %
Corporate Debt	—	132	—	—	—	132	7.5 %
Foreign Debt	—	27	—	—	—	27	1.5 %
State and Local Government	58	5	—	—	—	63	3.5 %
Subtotal – Fixed Income	57	322	—	—	133	512	28.9 %
Trust Owned Life Insurance:							
International Equities	—	23	—	—	—	23	1.3 %
United States Bonds	—	118	—	—	—	118	6.7 %
Subtotal – Trust Owned Life Insurance	—	141	—	—	—	141	8.0 %
Cash and Cash Equivalents (a)	28	—	—	—	3	31	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	—	14	14	0.8 %
Total	\$ 1,033	\$ 463	\$ —	\$ —	\$ 280	\$ 1,776	100.0 %

(a) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

Accumulated Benefit Obligation

The accumulated benefit obligation for the pension plans is as follows:

	December 31,	
	2025	2024
	(in thousands)	
Qualified Pension Plan	\$ 110,486	\$ 111,430
Nonqualified Pension Plan	8	17
Total Accumulated Benefit Obligation	\$ 110,494	\$ 111,447

Obligations in Excess of Fair Values

The tables below show the underfunded pension plans that had obligations in excess of plan assets.

Projected Benefit Obligation

	Underfunded Pension Plans	
	December 31,	
	2025	2024
	(in thousands)	
Projected Benefit Obligation	\$ 114,021	\$ 114,278
Fair Value of Plan Assets	113,546	109,278
Underfunded Projected Benefit Obligation	\$ (475)	\$ (5,000)

Accumulated Benefit Obligation

	Underfunded Pension Plans	
	December 31,	
	2025	2024
	(in thousands)	
Accumulated Benefit Obligation	\$ 8	\$ 111,447
Fair Value of Plan Assets	—	109,278
Underfunded Accumulated Benefit Obligation	\$ (8)	\$ (2,169)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the Pension and OPEB plans of \$1.8 million and \$7 thousand, respectively, during 2026. The estimated contributions to the pension trust are at least the minimum amount required by the Employee Retirement Income Security Act and additional discretionary contributions may also be made to maintain the funded status of the plan.

The table below reflects the total benefits expected to be paid from the plan or from KPCo's assets. The payments include the participants' contributions to the plan for their share of the cost. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Estimated Payments	
	Pension Plans	OPEB
	(in thousands)	
2026	\$ 10,213	\$ 3,903
2027	11,016	3,714
2028	11,057	3,446
2029	10,541	3,315
2030	9,819	3,173
Years 2031 to 2035, in Total	45,676	14,707

Components of Net Periodic Benefit Cost (Credit)

The following table provides the components of net periodic benefit cost (credit):

	Pension Plans		OPEB	
	Years Ended December 31,			
	2025	2024	2025	2024
	(in thousands)			
Service Cost	\$ 1,551	\$ 1,604	\$ 47	\$ 56
Interest Cost	6,250	6,127	1,041	1,373
Expected Return on Plan Assets	(8,442)	(9,422)	(3,682)	(3,853)
Amortization of Prior Service Credit	—	—	(66)	(374)
Amortization of Net Actuarial Loss	448	93	—	118
Settlements	—	1,689	—	—
Net Periodic Benefit Cost (Credit)	(193)	91	(2,660)	(2,680)
Capitalized Portion	(843)	(868)	(26)	(30)
Net Periodic Benefit Credit Recognized in Expense	\$ (1,036)	\$ (777)	\$ (2,686)	\$ (2,710)

American Electric Power System Retirement Savings Plan

KPCo participates in an AEPSC sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions totaled \$1.5 million in 2025 and \$1.4 million in 2024.

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of KPCo.

KPCo is exposed to certain market risks as a major power producer and participant in the electricity, natural gas, coal and emission allowance markets. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact KPCo due to changes in the underlying market prices or rates. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, KPCo primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

KPCo utilizes power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. KPCo utilizes interest rate derivative contracts in order to manage the interest rate exposure associated with its commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. KPCo may also utilize derivative contracts to manage interest rate risk associated with debt financing. For disclosure purposes, these risks are grouped as "Interest Rate." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with the established risk management policies as approved by the Finance Committee of the Board of Directors of AEP.

The following table represents the gross notional volume of KPCo's outstanding derivative contracts:

Primary Risk Exposure	December 31,		Unit of Measure
	2025	2024	
	(in thousands)		
Commodity:			
Power	4,778	4,832	MWhs
Natural Gas	8,283	9,783	MMBtus
Heating Oil and Gasoline	52	48	Gallons

Cash Flow Hedging Strategies

KPCo utilizes cash flow hedges on certain derivative transactions for the purchase and sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. KPCo does not hedge all commodity price risk.

KPCo may utilize a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo may also utilize interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. KPCo does not hedge all interest rate exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON KPCO'S FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third-party contractual agreements and risk profiles. KPCo netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of \$4 thousand and \$395 thousand as of December 31, 2025 and 2024, respectively. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets as of December 31, 2025 and 2024.

The following tables represent the gross fair value of KPCo's derivative activity on the balance sheets:

Statement of Financial Position Location	December 31, 2025		
	Risk Management Contracts – Commodity (a)	Gross Amounts Offset on the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented on the Statement of Financial Position (c)
	(in thousands)		
Derivative Instrument Assets	\$ 10,795	\$ (1,240)	\$ 9,555
Long-Term Portion of Derivative Instrument Assets	1,095	(566)	529
Derivative Instrument Liabilities	1,680	(1,244)	436
Long-Term Portion of Derivative Instrument Liabilities	633	566	67
Balance Sheet Location	December 31, 2024		
	Risk Management Contracts – Commodity (a)	Gross Amounts Offset on the Balance Sheets (b)	Net Amounts of Assets/Liabilities Presented on the Balance Sheets (c)
	(in thousands)		
Derivative Instrument Assets	\$ 6,775	\$ (1,083)	\$ 5,692
Long-Term Portion of Derivative Instrument Assets	595	(158)	437
Derivative Instrument Liabilities	1,939	(1,478)	461
Long-Term Portion of Derivative Instrument Liabilities	165	158	7

(a) Derivative instruments within this category are disclosed as gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."

(c) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.

The table below presents KPCo's activity of derivative risk management contracts:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31,	
	2025	2024
	(in thousands)	
Operating Revenues	\$ —	\$ 3
Operation Expenses	(1)	96
Maintenance Expenses	(4)	(4)
Other Regulatory Assets (a)	—	10,023
Other Regulatory Liabilities (a)	14,117	8,536
Total Gain (Loss) on Risk Management Contracts	\$ 14,112	\$ 18,654

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same line item on the statements of income as that of the associated risk being hedged. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

Credit Risk

Management mitigates credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses credit agency ratings and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a default including failure or inability to post collateral when required.

Collateral Triggering Events

Credit Downgrade Triggers

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. KPCo has not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. As of December 31, 2025 and 2024, KPCo did not have derivative contracts with collateral triggering events in a net liability position.

Cross-Acceleration Triggers

Certain interest rate derivative contracts contain cross-acceleration provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-acceleration provisions could be triggered if there was a non-performance event by KPCo under any of their outstanding debt of at least \$50 million and the lender on that debt has accelerated the entire repayment obligation. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-acceleration provisions in contracts. KPCo had no derivative contracts with cross-acceleration provisions in a net liability position and no cash collateral posted as of December 31, 2025 and 2024. If a cross-acceleration provision would have been triggered, settlement at fair value would have been required.

Cross-Default Triggers

In addition, a majority of KPCo's non-exchange-traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third-party obligation that is \$50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. KPCo had derivative contracts with cross-default provisions in a net liability position of \$370 thousand and \$212 thousand, and no cash collateral posted as of December 31, 2025 and 2024, respectively. If a cross-default provision would have been triggered, settlement at fair value would have been required.

8. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-Term Debt

The fair values of Long-Term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-Term Debt are summarized in the following table:

	December 31,					
	2025		2024			
	Book Value	Fair Value	Book Value	Fair Value		
	(in thousands)					
Long-Term Debt	\$ 1,064,474	\$ 1,095,194	\$ 1,214,407	\$ 1,222,803		

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

December 31, 2025

Assets:	Level 1	Level 2	Level 3	Other	Total
	(in thousands)				
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	\$ —	\$ 2,173	\$ 8,500	\$ (1,118)	\$ 9,555
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	\$ —	\$ 1,558	\$ —	\$ (1,122)	\$ 436

Assets and Liabilities Measured at Fair Value on a Recurring Basis

December 31, 2024

Assets:	Level 1	Level 2	Level 3	Other	Total
	(in thousands)				
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	\$ —	\$ 1,907	\$ 4,858	\$ (1,072)	\$ 5,691
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	\$ —	\$ 1,902	\$ 27	\$ (1,468)	\$ 461

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Substantially comprised of power contracts.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2025		Net Risk Management Assets (Liabilities) (in thousands)	
Balance as of December 31, 2024		\$	4,831
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)			5,288
Settlements			(10,120)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)			8,501
Balance as of December 31, 2025		<u>\$</u>	<u>8,500</u>

Year Ended December 31, 2024		Net Risk Management Assets (Liabilities) (in thousands)	
Balance as of December 31, 2023		\$	2,514
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)			4,022
Settlements			(6,536)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)			4,831
Balance as of December 31, 2024		<u>\$</u>	<u>4,831</u>

- (a) Included in revenues on KPCo's statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Relates to the net gains (losses) of those contracts that are not reflected on KPCo's statements of income. These changes in fair value are recorded as regulatory liabilities for net gains and as regulatory assets for net losses.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of December 31, 2025 and 2024:

Significant Unobservable Inputs December 31, 2025							
	Fair Value		Valuation Technique	Significant Unobservable Input (a)	Input/Range		
	Assets	Liabilities			Low	High	Weighted Average(b)
	(in thousands)						
FTRs	\$ 8,500	\$ —	Discounted Cash Flow	Forward Market Price	\$ 0.01	\$ 16.65	\$ 1.97

Significant Unobservable Inputs December 31, 2024							
	Fair Value		Valuation Technique	Significant Unobservable Input (a)	Input/Range		
	Assets	Liabilities			Low	High	Weighted Average(b)
	(in thousands)						
FTRs	\$ 4,858	\$ 27	Discounted Cash Flow	Forward Market Price	\$ (0.22)	\$ 9.32	\$ 1.08

- (a) Represents market prices in dollars per MWh.
(b) The weighted-average is the product of the forward market price of the underlying commodity and volume weighted by term.

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of December 31, 2025 and 2024:

Uncertainty of Fair Value Measurements				
Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement	
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)	
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)	

9. INCOME TAXES

Income Tax Expense (Benefit)

The details of KPCo's Income Tax Expense are as follows:

	Years Ended December 31,	
	2025	2024
	(in thousands)	
Charged (Credited) to Operating Expense, Net:		
Current	\$ (2,914)	\$ 3,514
Deferred	11,214	863
Total	<u>8,300</u>	<u>4,377</u>
Charged (Credited) to Non-Operating Income, Net:		
Current	(1,746)	(1,396)
Deferred	—	—
Total	<u>(1,746)</u>	<u>(1,396)</u>
Income Tax Expense (Benefit)	<u>\$ 6,554</u>	<u>\$ 2,981</u>

The following is a reconciliation between the federal income taxes computed by multiplying pretax income by the federal statutory tax rate and the income taxes reported:

	Years Ended December 31,					
	2025		2024			
	(in thousands)					
Net Income	\$	40,796	\$	36,862		
Income Tax Expense (Benefit)		6,554		2,981		
Pretax Income	\$	47,350	\$	39,843		
	Amount	Percent	Amount	Percent		
US Federal Statutory Tax Rate	\$	9,944	21.0%	\$	8,367	21.0%
State and Local Income Taxes, Net (a)		(1,524)	(3.2)%		(818)	(2.1)%
Tax Credits		6	—%		(114)	(0.3)%
Non-Taxable or Non-Deductible Items		63	0.1%		37	0.1%
Other Adjustments:						
Reversal of Origination Flow-Through		2,550	5.4%		2,410	6.0%
Tax Reform Excess ADIT Reversal		(2,677)	(5.7)%		(6,626)	(16.6)%
AFUDC Equity		(850)	(1.8)%		(324)	(0.8)%
Other		(958)	(2.0)%		49	0.2%
Income Tax Expense (Benefit)	\$	6,554		\$	2,981	
Effective Income Tax Rate		13.8%			7.5%	

(a) State taxes in Kentucky contributed to the majority of the tax effect.

Income Taxes Paid

KPCo paid \$8 million and \$1 million to tax authorities in 2025 and 2024 respectively.

Net Deferred Tax Liability

The following table shows elements of KPCo's net deferred tax liability and significant temporary differences.

	December 31,			
	2025		2024	
	(in thousands)			
Deferred Tax Assets	\$	82,093	\$	82,133
Deferred Tax Liabilities		(576,772)		(566,150)
Net Deferred Tax Liabilities	\$	(494,679)	\$	(484,017)
Property Related Temporary Differences	\$	(378,030)	\$	(371,937)
Amounts Due to Customers for Future Income Taxes		26,196		28,689
Securitized Assets		(114,849)		—
Regulatory Assets		(41,143)		(155,750)
Net Operating Loss Carryforward		14,540		13,016
Tax Credit Carryforward		3,450		3,030
All Other, Net		(4,843)		(1,065)
Net Deferred Tax Liabilities	\$	(494,679)	\$	(484,017)

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are not currently under IRS audit and the statute of limitations (SOL) for the IRS to examine KPCo and other AEP subsidiaries originally filed federal return has expired for tax years prior to 2022. In July 2025, KPCo and other AEP subsidiaries received notification that their 2023 federal income tax return was selected for IRS examination. However, this examination has yet to begin.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. KPCo and other AEP subsidiaries are not currently under any state and local income tax examinations. Generally, the SOL have expired for tax years prior to 2022. In addition, management is monitoring and continues to evaluate the potential impact of federal legislation and corresponding state conformity.

Net Income Tax Operating Loss Carryforward

KPCo had no federal net income tax operating loss carryforward (NOLC) as of December 31, 2025 and 2024. KPCo has state NOLCs of \$177 million and \$178 million in 2025 and 2024, respectively. As a result, KPCo will recognize future deferred state income tax benefits of \$9 million. These carryforwards will begin to expire the year ended December 31, 2035. Management anticipates future taxable income will be sufficient to realize the state net income tax operating loss tax benefits.

10. LEASES

KPCo leases property, plant and equipment including, but not limited to, fleet, information technology and real estate leases. These leases require payments of non-lease components, including related property taxes, operating and maintenance costs. KPCo does not separate non-lease components from associated lease components. Many of these leases have purchase or renewal options. Leases not renewed are often replaced by other leases. Options to renew or purchase a lease are included in the measurement of lease assets and liabilities if it is reasonably certain that KPCo will exercise the option.

Lease obligations are measured using the discount rate implicit in the lease when that rate is readily determinable. KPCo has visibility into the rate implicit in the lease when assets are leased from selected financial institutions under master leasing agreements. When the implicit rate is not readily determinable, KPCo measures its lease obligation using its estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk-free rate and a secured credit spread relative to the lessee on a matched maturity basis.

Operating lease rentals and finance lease amortization costs are generally charged to Operation Expenses and Maintenance Expenses in accordance with rate-making treatment for regulated operations. Lease costs associated with capital projects are included in Utility Plant on the balance sheets. For regulated operations with finance leases, a finance lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Finance leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs were as follows:

Lease Rental Costs	Years Ended December 31,			
	2025		2024	
	(in thousands)			
Operating Lease Cost	\$	701	\$	258
Finance Lease Cost:				
Amortization of Finance Leases		160		118
Interest on Finance Leases		160		55
Total Lease Rental Costs (a)	\$	1,021	\$	431

(a) Excludes variable and short-term lease costs, which were immaterial.

Supplemental information related to leases are shown in the tables below.

Lease Type	Years Ended December 31,			
	Weighted-Average Remaining Lease Term (years):		Weighted-Average Discount Rate	
	December 31,			
	2025	2024	2025	2024
Operating Leases	4.61	4.51	5.60%	5.42%
Finance Leases	6.31	7.17	6.59%	6.52%

	Years Ended December 31,			
	2025		2024	
	(in thousands)			

Cash Paid for Amounts Included in the Measurement of Lease Liabilities

Operating Cash Flows Used for Operating Leases	\$	701	\$	258
Operating Cash Flows Used for Finance Leases		235		176
Non-cash Acquisitions Under Operating Leases	\$	1,975	\$	844

The following tables show property, plant and equipment under finance leases, operating leases and related obligations recorded on KPCo's balance sheets. Lease obligations are not recognized on the balance sheets for lease agreements with a lease term of less than twelve months:

	December 31,	
	2025	2024
(in thousands)		
Property, Plant and Equipment Under Finance Leases		
Utility Plant (a)	\$ 1,430	\$ 914
Obligations Under Finance Leases		
Noncurrent	1,191	779
Current	233	135
Total Obligations Under Finance Leases	\$ 1,424	\$ 914

(a) Includes \$568 thousand and \$415 thousand of accumulated provision for depreciation and amortization for the years ended December 31, 2025 and 2024, respectively.

	December 31,	
	2025	2024
(in thousands)		
Property, Plant and Equipment Under Operating Leases		
Utility Plant (a)	\$ 3,612	\$ 1,968
Obligations Under Operating Leases		
Noncurrent	2,907	1,795
Current	749	216
Total Obligations Under Operating Leases	\$ 3,656	\$ 2,011

(a) Includes \$877 thousand and \$368 thousand of accumulated provision for depreciation and amortization for the years ended December 31, 2025 and 2024, respectively.

Future minimum lease payments consisted of the following as of December 31, 2025:

	Future Minimum Lease Payments	
	Finance Leases	Operating Leases
(in thousands)		
2026	\$ 320	\$ 959
2027	306	938
2028	239	913
2029	221	788
2030	205	352
After 2030	485	232
Total Future Minimum Lease Payments	1,776	4,182
Less: Imputed Interest	352	526
Estimated Present Value of Future Minimum Lease Payments	\$ 1,424	\$ 3,656

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of December 31, 2025, the maximum potential loss for these lease agreements was \$252 thousand assuming the fair value of the equipment is zero at the end of the lease term.

Lessor Activity

KPCo's lessor activity was immaterial as of and for the twelve months ended December 31, 2025 and December 31, 2024, respectively.

11. FINANCING ACTIVITIES

Long-Term Debt

The following table details long-term debt outstanding:

Type of Debt	Maturity	Weighted-Average Interest Rate as of December 31, 2025	Interest Rate Ranges as of December 31,		Outstanding as of December 31,	
			2025	2024	2025	2024
(in thousands)						
Senior Unsecured Notes	2026-2047	5.55%	3.35%-8.13%	3.35%-8.13%	\$ 1,000,000	\$ 1,000,000
Pollution Control Bonds	2026 (a)	4.70%	4.70%	4.70%	65,000	65,000
Other Long-Term Debt	2025	—%	—%	5.42%	—	150,000
Unamortized Discount, Net					(526)	(593)
Total Long-Term Debt					\$ 1,064,474	\$ 1,214,407

(a) KPCo's Pollution Control Bond is subject to redemption earlier than the maturity date.

As of December 31, 2025, outstanding long-term debt was payable as follows:

	2026	2027	2028	2029	2030	After 2030	Total
	(in thousands)						
Principal Amount	\$ 265,000	\$ 40,000	\$ —	\$ 195,000	\$ —	\$ 565,000	\$ 1,065,000
Unamortized Discount, Net						(526)	(526)
Total Long-Term Debt						\$ 564,474	\$ 1,064,474

Dividend Restrictions

KPCo pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KPCo to transfer funds to Parent in the form of dividends.

All of the dividends declared by KPCo are subject to a Federal Power Act requirement that prohibits the payment of dividends out of capital accounts in certain circumstances; payment of dividends is generally allowed out of retained earnings.

KPCo has credit agreements that contain a covenant that limit its debt to capitalization ratio to 67.5%. As of December 31, 2025, KPCo did not exceed its debt to capitalization limit. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The most restrictive dividend limitation for KPCo is through the Credit Agreements. As of December 31, 2025, the maximum amount of restricted net assets of KPCo that may not be distributed to Parent in the form of a loan, advance or dividend was \$577.6 million.

The Federal Power Act restriction does not limit the ability of KPCo to pay dividends out of retained earnings. The credit agreement covenant restrictions can limit the ability of KPCo to pay dividends out of retained earnings. As of December 31, 2025, there were no restrictions on KPCo's ability to pay dividends out of retained earnings.

Corporate Borrowing Program – AEP System

AEP subsidiaries use a corporate borrowing program to meet their short-term borrowing needs. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of December 31, 2025 and 2024 are included in Notes Receivable from Associated Companies and Notes Payable to Associated Companies, respectively, on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits are described in the following table:

Years Ended December 31,	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Net Loans to (Borrowings from) the Utility Money Pool as of December 31,	Authorized Short-term Borrowing Limit
	(in thousands)					
2025	\$ 183,236	\$ 73,869	\$ 49,600	\$ 45,605	\$ 16,416	\$ 250,000
2024	\$ 206,113	\$ —	\$ 93,082	\$ —	\$ (183,212)	\$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

Years Ended December 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2025	4.83 %	4.14 %	4.73 %	3.40 %	4.67 %	4.41 %
2024	5.79 %	4.74 %	— %	— %	5.27 %	— %

Interest expense and interest income related to the Utility Money Pool are included in Interest on Debt to Associated Companies and Interest and Dividend Income, respectively, on KPCo's statements of income. For amounts borrowed from and loaned to the Utility Money Pool, KPCo incurred the following amounts of interest expense and earned the following amounts of interest income:

	Years Ended December 31,	
	2025	2024
	(in thousands)	
Interest Expense	\$ 1,262	\$ 5,345
Interest Income	1,133	—

Securitized Accounts Receivables – AEP Credit

Under an affiliated receivables sales arrangement, KPCo sold, without recourse, certain of its customer accounts receivable and accrued utility revenue balances to AEP Credit. KPCo is charged a fee for each sale that is based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience from previous purchases of KPCo's customer accounts receivable. No allowance for credit losses is recognized within KPCo's financial statements for customer accounts receivable sold to AEP Credit, and any bad debt stemming from these receivables would be recognized by AEP Credit. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's statements of income. KPCo manages and services its accounts receivables sold.

AEP Credit's receivables securitization agreement provides a commitment of \$900 million from bank conduits to purchase receivables and expires in September 2027. As of December 31, 2025, KPCo was in compliance with all requirements under the agreement.

KPCo's amounts of accounts receivable and accrued unbilled revenues under the sale of receivables agreement were \$64.6 million and \$53.4 million as of December 31, 2025 and 2024, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were \$5.0 million and \$5.0 million for the years ended December 31, 2025 and 2024, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were \$688.6 million and \$642.8 million for the years ended December 31, 2025 and 2024, respectively.

12. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Income Taxes" section of Note 1 in addition to "Corporate Borrowing Program – AEP System" and "Securitized Accounts Receivables – AEP Credit" sections of Note 11.

Intercompany Billings

KPCo performs certain utility services for other AEP subsidiaries when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

Power Coordination Agreement

Effective January 1, 2014, the FERC approved the PCA. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions.

KPCo's direct purchases from AEP East Companies through the PCA were \$225 thousand and \$373 thousand for the years ended December 31, 2025 and 2024, respectively. These direct purchases are presented as Purchased Electricity from AEP Affiliates on the statements of income.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet and then transfers the cost to the affiliate for reimbursement. KPCo recorded its assigned portion of these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. KPCo's billed amounts were \$342 thousand and \$418 thousand for the years ended December 31, 2025 and 2024, respectively.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to \$100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions and the net book value of all sales and purchases for the years ended December 31, 2025 and 2024 were not material. These sales and purchases are recorded in Utility Plant on the balance sheets.

PJM Transmission Service Charges

The AEP East Companies are parties to the TA, which defines how transmission costs through PJM OATT are allocated among the AEP East Companies on a 12-month average coincident peak basis. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to KPCo through the PJM OATT.

KPCo's net charges recorded as a result of the TA for the years ended December 31, 2025 and 2024 were \$83.4 million and \$75.5 million, respectively, and were recorded in Operation Expenses on KPCo's statements of income.

Charitable Contributions to AEP Foundation

The AEP Foundation is funded by AEP and its utility operating units. The AEP Foundation provides a permanent, ongoing resource for charitable initiatives and multi-year commitments in the communities served by AEP and initiatives outside of AEP's 11-state service area. The AEP Foundation is not consolidated by AEP. Charitable contributions to the AEP Foundation of \$330 thousand were recorded in Other Operation expenses on the statements of income for the year ended December 31, 2025. Charitable contributions to the AEP Foundation were not made in 2024.

Affiliated Revenues

The table below shows the revenues derived from auction sales to affiliates, net transmission agreement sales and other revenues as follows:

Related Party Revenues	Years Ended December 31,	
	2025	2024
	(in thousands)	
Transmission Agreement Sales	\$ 29,574	\$ 13,283
Other Revenues	1,834	1,229
Total Affiliated Revenues	\$ 31,408	\$ 14,512

13. PROPERTY, PLANT AND EQUIPMENT

Depreciation

KPCo provides for depreciation of Utility Plant on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides total regulated annual composite depreciation rates and depreciable lives for KPCo. Nonregulated depreciation rate ranges and depreciable life ranges are not applicable or not meaningful for 2025 and 2024.

Year	Steam	Transmission	Distribution	General
	(in percentages)			
2025	3.0 %	2.7 %	3.4 %	8.2 %
2024	2.7 %	2.5 %	3.4 %	8.5 %

The composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to accumulated depreciation on the balance sheets. Actual removal costs incurred are charged to accumulated depreciation.

Asset Retirement Obligations (ARO)

In April 2024, the Federal EPA finalized revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land. In the second quarter of 2024, KPCo evaluated the applicability of the rule to current and former plant sites and incurred ARO liabilities of \$64.4 million and revised cash flow estimates by an additional \$3.6 million based on initial cost estimates. See the "Federal EPA's Revised CCR Rule" section of Note 5 for additional information.

The following is a reconciliation of the 2025 and 2024 aggregate carrying amounts of ARO for KPCo:

Year	ARO as of January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled (a)	Revisions in Cash Flow Estimates (a)	ARO as of December 31,
			(in thousands)			
2025	\$ 88,833	\$ 5,210	\$ —	\$ (902)	\$ (1,035)	\$ 92,106
2024	18,276	2,587	66,399	(924)	2,495	88,833

(a) Primarily related to ash pond closure and asbestos abatement.

Jointly-owned Electric Facilities

KPCo, jointly with WPCo, owns Unit 1 and Unit 2 of the Mitchell Generating Station. KPCo and WPCo each have a 50% ownership of Unit 1 and Unit 2 of the Mitchell Generating Station. Using its own financing, each participating company is obligated to pay its share of the costs in the same proportion as its ownership interest. KPCo's proportionate share of the operating costs associated with this facility is included in its statements of income and the investment and accumulated depreciation are reflected in its balance sheets under Utility Plant as follows:

	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
(in thousands)					
KPCo's Share as of December 31, 2025					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	\$ 1,089,417	\$ 2,586	\$ 565,323
KPCo's Share as of December 31, 2024					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	\$ 1,088,611	\$ 3,680	\$ 545,520

(a) Operated by WPCo.

14. REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregated Revenues from Contracts with Customers

The table below represents KPCo's revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Years Ended December 31,	
	2025	2024
	(in thousands)	
Retail Revenues:		
Residential Revenues	\$ 311,616	\$ 278,699
Commercial Revenues	198,147	190,145
Industrial Revenues	164,626	167,490
Other Retail Revenues	2,036	2,147
Total Retail Revenues	<u>676,425</u>	<u>638,481</u>
Wholesale Revenues:		
Generation Revenues	34,452	23,662
Transmission Revenues (a)	55,748	30,070
Total Wholesale Revenues	<u>90,200</u>	<u>53,732</u>
Other Revenues from Contracts with Customers (b)	<u>13,481</u>	<u>11,486</u>
Total Revenues from Contracts with Customers	<u>780,106</u>	<u>703,699</u>
Other Revenues:		
Alternative Revenue Programs (b) (c)	(15,582)	2,880
Other Revenues	227	3
Total Other Revenues	<u>(15,355)</u>	<u>2,883</u>
Total Operating Revenues	<u>\$ 764,751</u>	<u>\$ 706,582</u>

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues were \$35.2 million and \$13.8 million for years ended December 31, 2025 and 2024, respectively.

(b) Amounts include affiliated and nonaffiliated revenues.

(c) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

Performance Obligations

KPCo has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for "Revenue from Contracts with Customers" allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity's measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. KPCo elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for KPCo are summarized as follows:

Retail Revenues

KPCo has performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer's usage requirements.

Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between KPCo and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice.

Wholesale Revenues - Generation

KPCo has performance obligations to sell electricity to wholesale customers from generation assets in PJM. The performance obligation to deliver electricity from generation assets is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Wholesale generation revenues are variable as they are subject to the customer's usage requirements.

KPCo also has performance obligations to stand ready in order to promote grid reliability. Stand ready services are sold into PJM's RPM capacity market. RPM entails a base auction and at least three incremental auctions for a specific PJM delivery year, with the incremental auctions spanning three years. The performance obligation to stand ready is satisfied over time and the consideration for which is variable until the occurrence of the final incremental auction, at which point the performance obligation becomes fixed.

Payments from the RTO for stand ready services are typically received within one week from the issuance of the invoice, which is typically issued weekly. Gross margin resulting from generation sales are primarily subject to margin sharing agreements with customers, where the revenues are reflected gross in the disaggregated revenues table above.

Wholesale Revenues - Transmission

KPCo has performance obligations to transmit electricity to wholesale customers through assets owned and operated by KPCo and other AEP subsidiaries. The performance obligation to provide transmission services in PJM is partially fixed for a period of one year or less. Payments from the RTO for transmission services are typically received within one week from the issuance of the invoice, which is issued weekly for PJM.

KPCo collects revenues through transmission formula rates. The FERC-approved rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations," and are therefore presented as such in the disaggregated revenues table above.

The AEP East Companies are parties to the TA, which defines how transmission costs are allocated among the AEP East Companies on a 12-month average coincident peak basis. AEPTCo is a load serving entity within PJM providing transmission services to affiliates in accordance with the OATT and TA. Affiliate revenues as a result of the TA are reflected as Transmission Revenues in the disaggregated revenues table above.

Fixed Performance Obligations

The following table represents KPCo's remaining fixed performance obligations satisfied over time as of December 31, 2025. Fixed performance obligations primarily include electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. KPCo elected to apply the exemption to not disclose the value of unsatisfied performance obligations for contracts with an original expected term of one year or less. Due to the annual establishment of revenue requirements, transmission revenues are excluded from the table below. The amounts shown in the table below include affiliated and nonaffiliated revenues.

	2026	2027-2028	2029-2030	After 2030	Total
	(in thousands)				
\$	1,435	\$ 2,870	\$ 2,870	\$ 1,435	\$ 8,610

Contract Assets and Liabilities

Contract assets are recognized when KPCo has a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. KPCo did not have material contract assets as of December 31, 2025 and 2024.

When KPCo receives consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheet in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. KPCo's contract liabilities typically arise from advanced payments of services provided primarily with respect to joint use agreements for utility poles. KPCo did not have material contract liabilities as of December 31, 2025 and 2024.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on KPCo's balance sheets within the Customer Accounts Receivable line item. KPCo's balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Customer Accounts Receivable were not material as of December 31, 2025 and 2024. See "Securitized Accounts Receivable - AEP Credit" section of Note 11 for additional information.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable from Associated Companies on KPCo's balance sheets were \$15.7 million and \$14.1 million, respectively, as of December 31, 2025 and 2024.

Contract Costs

Contract costs to obtain or fulfill a contract are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and neither bifurcated nor reclassified between current assets and deferred debits on KPCo's balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Operation Expenses on KPCo's statements of income. KPCo did not have material contract costs as of December 31, 2025 and 2024.

15. FERC ORDER No. 898

On June 29, 2023, the FERC issued Order No. 898 that revised certain aspects of the accounting and reporting requirements under the Uniform System of Accounts. The order created new accounts for wind, solar, and other renewable generating assets, created a new functional class for energy storage accounts, codified the accounting treatment of environmental credits and created new accounts within existing functions for computer hardware, software, and communication equipment. The order is effective January 1, 2025.

The historical balances were transferred to the new accounts in the first quarter of 2025 without restating balances for prior years. The following table presents the KPCo's balance transferred as of December 31, 2025, as required by FERC Order No. 898:

Utility Account	December 31, 2025	
	Transfers	
	(in thousands)	
30300 - Intangible Property	\$	(57,067)
31510 - Computer Hardware Coal		41
31531 - Comm Equipment Coal		137
31600 - Misc Pwr Plant Equip-Coal		(173)
35120 - Computer Software		101
35130 - Communication Equipment		231
36320 - Computer Software		36
36330 - Communication Equipment		354
36336 - AMI Communication Equipment		1,621
39100 - Office Furniture, Equipment		(817)
39111 - Office Equip - Computers		(495)
39700 - Communication Equipment		(45,718)
39710 - Computer Hardware		1,312
39716 - GridSmart Communic Equip		(1,620)
39721 - Computer Software		56,930
39730 - Communication Equipment		45,170
39800 - Miscellaneous Equipment		(43)
Net Transfers	\$	—

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		

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)								36,861,721	36,861,721
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)								40,796,226	40,796,226
10	Balance of Account 219 at End of Current Quarter/Year									

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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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)	3,441,259,511	3,441,259,511					
4	Property Under Capital Leases	5,042,231	5,042,231					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	317,000,884.00	317,000,884.00					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	3,763,302,626	3,763,302,626					
9	Leased to Others							
10	Held for Future Use	801,670	801,670					
11	Construction Work in Progress	195,656,532	195,656,532					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	3,959,760,828	3,959,760,828					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,423,091,181	1,423,091,181					
15	Net Utility Plant (13 less 14)	2,536,669,647	2,536,669,647					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	1,423,032,107	1,423,032,107					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	59,074	59,074					
22	Total in Service (18 thru 21)	1,423,091,181	1,423,091,181					
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)	1,423,091,181	1,423,091,181					

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

- Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
- If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction					
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)					
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)					
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)					
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> 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						
3	(302) Franchise and Consents	52,919					52,919
4	(303) Miscellaneous Intangible Plant	56,823,035	151,245			(56,974,280)	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	56,875,954	151,245			(56,974,280)	52,919
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	4,986,112					4,986,112
9	(311) Structures and Improvements	102,301,305	4,589,119	160,768			106,729,656
10	(312) Boiler Plant Equipment	979,140,218	4,148,928	5,011,159			978,277,987
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	120,869,820	903,616	1,186,533			120,586,903
13	(315) Accessory Electric Equipment	34,594,933	378,648	534,541			34,439,040
13.1	(315.1) Computer Hardware					41,318	41,318
13.2	(315.2) Computer Software						
13.3	(315.3) Communication Equipment					137,459	137,459
14	(316) Misc. Power Plant Equipment	14,317,723	281,712	117,892		(173,171)	14,308,372
15	(317) Asset Retirement Costs for Steam Production	34,041,525	(993,985)				33,047,540
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,290,251,636	9,308,038	7,010,893		5,606	1,292,554,387
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						
28	(331) Structures and Improvements						
29	(332) Reservoirs, Dams, and Waterways						
30	(333) Water Wheels, Turbines, and Generators						
31	(334) Accessory Electric Equipment						
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)
31.2	(334.2) Computer Software						
31.3	(334.3) Communication Equipment						
32	(335) Misc. Power Plant Equipment						
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)						
35.1	D. Solar Production Plant						
35.2	(338.1) Land and Land Rights						
35.3	(338.2) Structures and Improvements						
35.5	(338.4) Solar Panels						
35.6	(338.5) Collector System						
35.7	(338.6) Generator Step-up Transformers (GSU)						
35.8	(338.7) Inverters						
35.9	(338.8) Other Accessory Electrical Equipment						
35.10	(338.9) Computer Hardware						
35.11	(338.10) Computer Software						
35.12	(338.11) Communication Equipment						
35.13	(338.12) Miscellaneous Power Plant Equipment						
35.14	(338.13) Asset Retirement Costs for Solar Production						
35.15	TOTAL Solar Production Plant (Enter Total of lines 35.2 thru 35.14)						
35.16	E. Wind Production Plant						
35.17	(338.20) Land and Land Rights						
35.18	(338.21) Structures and Improvements						
35.20	(338.23) Wind Turbines						
35.21	(338.24) Wind Towers and Fixtures						
35.23	(338.26) Collector System						
35.24	(338.27) Generator Step-up Transformers (GSU)						
35.25	(338.28) Inverters						
35.26	(338.29) Other Accessory Electrical Equipment						
35.27	(338.30) Computer Hardware						
35.28	(338.31) Computer Software						
35.29	(338.32) Communication Equipment						
35.30	(338.33) Miscellaneous Power Plant Equipment						
35.31	(338.34) Asset Retirement Costs for Wind Production						
35.32	TOTAL Wind Production Plant (Enter Total of lines 35.17 thru 35.31)						
35.33	F. Other Renewable Production Plant						
35.34	(339.1) Land and Land Rights						
35.35	(339.2) Structures and Improvements						
35.36	(339.3) Fuel Holders						
35.37	(339.4) Boilers						
35.39	(339.6) Generators						
35.41	(339.8) Other Accessory Electrical Equipment						
35.42	(339.9) Computer Hardware						
35.43	(339.10) Computer Software						
35.44	(339.11) Communication Equipment						
35.45	(339.12) Miscellaneous Power Plant Equipment						
35.46	(339.13) Asset Retirement Costs for Other Renewable Production						
35.47	TOTAL Other Renewable Production Plant (Enter Total of lines 35.34 thru 35.46)						
36	G. Other Production Plant						
37	(340) Land and Land Rights						
38	(341) Structures and Improvements						
39	(342) Fuel Holders, Products, and Accessories						
40	(343) Prime Movers						
41	(344) Generators						

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						
42.1	(345.1) Computer Hardware						
42.2	(345.2) Computer Software						
42.3	(345.3) Communication Equipment						
43	(346) Misc. Power Plant Equipment						
44	(347) Asset Retirement Costs for Other Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)						
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, 35.15, 35.32, 35.47, and 45)	1,290,251,636	9,308,038	7,010,893		5,606	1,292,554,387
47	3. Transmission Plant						
48	(350) Land and Land Rights	45,982,148	1,780,015	921			47,761,242
48.2	(351.1) Computer Hardware						
48.3	(351.2) Computer Software		2,578,941			101,226	2,680,167
48.4	(351.3) Communication Equipment		455,112			231,214	686,326
49	(352) Structures and Improvements	29,953,908	3,047,131	132,046			32,868,993
50	(353) Station Equipment	312,611,951	9,547,546	996,681			321,162,816
51	(354) Towers and Fixtures	124,140,774	4,272,974	134,394			128,279,354
52	(355) Poles and Fixtures	243,719,880	52,015,224	16,263,943			279,471,161
53	(356) Overhead Conductors and Devices	188,054,426	8,996,583	374,319			196,676,690
54	(357) Underground Conduit	5,861,949	503,579				6,365,528
55	(358) Underground Conductors and Devices	561,966	59,335				621,301
56	(359) Roads and Trails						
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	950,887,002	83,256,440	17,902,304		332,440	1,016,573,578
59	4. Distribution Plant						
60	(360) Land and Land Rights	11,972,702	342,002				12,314,704
61	(361) Structures and Improvements	19,221,492	998,815	71,195			20,149,112
62	(362) Station Equipment	170,184,994	4,209,109	1,379,700			173,014,403
63.1	(363.1) Computer Hardware						
63.2	(363.2) Computer Software		1,186,033			36,317	1,222,350
63.3	(363.3) Communication Equipment	1,504,921	5,107,182			453,643	7,065,746
64	(364) Poles, Towers, and Fixtures	328,602,239	39,952,170	2,775,830			365,778,579
65	(365) Overhead Conductors and Devices	339,026,211	27,875,431	3,950,875			362,950,767
66	(366) Underground Conduit	10,123,877	322,461	7,048			10,439,290
67	(367) Underground Conductors and Devices	13,367,991	977,510	82,456			14,263,045
68	(368) Line Transformers	170,079,086	10,761,216	2,504,102			178,336,200
69	(369) Services	79,160,695	3,680,953	445,806			82,395,842
70	(370) Meters	25,621,858	367,819	405,425			25,584,252
71	(371) Installations on Customer Premises	20,725,367	2,819,666	2,341,657			21,203,376
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	5,654,451	690,994	439,180			5,906,265
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,195,245,884	99,291,361	14,403,274		489,960	1,280,623,931
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	2,134,691	20,696				2,155,387
87	(390) Structures and Improvements	28,738,308	20,070				28,758,378
88	(391) Office Furniture and Equipment	3,810,505	22,052			(1,311,758)	2,520,799
89	(392) Transportation Equipment	24,068,505	133,708				24,202,213
90	(393) Stores Equipment	429,770	20,232	25,233			424,769
91	(394) Tools, Shop and Garage Equipment	8,108,338	1,175,735				9,284,073
92	(395) Laboratory Equipment	225,704					225,704
93	(396) Power Operated Equipment	2,221,244					2,221,244
94	(397.1) Computer Hardware		1,659			1,311,758	1,313,417
94.1	(397.2) Computer Software		5,819,044	12,191,113		56,836,738	50,464,669
94.2	(397.3) Communication Equipment	45,324,321	292,426	374,635		(647,239)	44,594,873
95	(398) Miscellaneous Equipment	2,197,248	7,602	30,390		(43,225)	2,131,235
96	SUBTOTAL (Enter Total of lines 86 thru 95)	117,258,634	7,513,224	12,621,371		56,146,274	168,296,761
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant	158,819					158,819
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	117,417,453	7,513,224	12,621,371		56,146,274	168,455,580
100	TOTAL (Accounts 101 and 106)	3,610,677,929	199,520,308	51,937,842			3,758,260,395
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)	3,610,677,929	199,520,308	51,937,842			3,758,260,395

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Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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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46						
47	TOTAL					

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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	Ramey Substation (4205)	10/01/2009	12/31/2026	556,145.00
3	Items under \$250,000			245,525
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
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47	TOTAL			801,670

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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	ADMS Imp DSN DNEX-KYP D	3,200,309
2	Bellefonte KY-T Supp	5,942,169
3	Bellefonte Upgrades Baseline	2,203,522
4	BS1 Gen Core Restack & Rewind	7,128,816
5	D/KP/Capital Blanket - KYPCo	1,580,643
6	Ed-Ci-Kepeco-D Ast Imp	3,046,010
7	Hatfield KPCO-T	2,080,776
8	Hazard DA 2019 - Shamrock	1,080,420
9	Kentucky Power Trans	10,739,431
10	KPCo - D Work	1,844,737
11	KPCo D Work 1	10,421,439
12	KPCo D Work 2	1,937,796
13	KPCo D Work 3	1,209,676
14	KPCO Distr CI	1,105,127
15	KPCo T work 1	59,168,499
16	KPCo T work 2	8,541,819
17	KPCo T work 3	4,821,991
18	KPCo T work 4	1,484,047
19	KY D Work	7,734,840
20	KY T Work	17,091,718
21	KYPCo Distr Pre Eng Parent	4,690,368
22	Ovation Evergreen Upgrade	1,062,409
23	Prestonsburg-Thelma KPCO-D	1,552,024
24	Prestonsburg-Thelma KPCO-T	5,641,178
25	T/KP/Capital Blanket - KYPCo	9,055,814
26	T/KY/Kentucky TTMP 2021	1,248,232
27	WS-CI-KEPCo-G PPB	6,581,703
28	Other Minor Projects Which is under 5% or \$1,000,000	13,461,019
43	Total	195,656,532

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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	1,336,283,179	1,336,283,179		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	120,883,595	120,883,595		
4	(403.1) Depreciation Expense for Asset Retirement Costs	1,875,227	1,875,227		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	(236,345)	(236,345)		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	122,522,477	122,522,477		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(51,937,843)	(51,937,843)		
13	Cost of Removal	(18,099,076)	(18,099,076)		
14	Salvage (Credit)	1,323,678	1,323,678		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(68,713,241)	(68,713,241)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	32,939,692	32,939,692		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,423,032,107	1,423,032,107		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	654,204,314	654,204,314		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
23.1	Solar Production				
23.2	Wind Production				
23.3	Other Renewable Production				
24	Other Production				
25	Transmission	305,069,220	305,069,220		
26	Distribution	396,626,356	396,626,356		
27	Regional Transmission and Market Operation				
27.1	Energy Storage				
28	General	67,132,217	67,132,217		
29	TOTAL (Enter Total of lines 20 thru 28)	1,423,032,107	1,423,032,107		

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1	Kentucky Power Cost Recovery, LLC	06/13/2025					2,388,745	
42	Total Cost of Account 123.1 \$		Total				2,388,745	

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MATERIALS AND SUPPLIES

- 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.
- 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)	57,068,481	46,823,106	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	2,421,988	2,253,140	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	13,556,414	14,529,718	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	9,971,316	10,739,353	Electric
8	Transmission Plant (Estimated)	10,431	36,281	Electric
9	Distribution Plant (Estimated)	349,096	275,979	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
10.1	Energy Storage Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	86,528	21,518	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	23,973,785	25,602,849	
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)			
17				
18				
19				
20	TOTAL Materials and Supplies	83,464,254	74,679,095	

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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/transferees 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	394,012	8,515,890	54,079		54,080		54,079		1,369,981		1,926,231	8,515,890
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	2,437		9,977						44,351		56,765	
5	Returned by authoritative agency												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509, 555.2, and 555.3	3,526	16,779									3,526	16,779
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Consent Decree Surrenders			39,166								39,166	
23													
24													
25													
26													
27													
28	Total			39,166								39,166	
29	Balance-End of Year	392,923	8,499,110	24,890		54,080		54,079		1,414,332		1,940,304	8,499,110
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												

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												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
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						
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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						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
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48						
49	TOTAL					

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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	AF1-130	97	186		
3	AF1-162				
4	AF2-018	299	186	299	186
5	AG1-066	997	186	997	186
6	AG2-184	451	186	451	186
7	AH1-136	83	186	83	186
8	AH1-227	292	186	292	186
20	Total				
21	Generation Studies				
39	Total				
40	Grand Total				

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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	2020 KY Storm Deferral	10,509,844		131	10,509,844	
2	2021 KY Storm Deferral	45,996,003		131	45,996,003	
3	2021 PJM Annual Transmission Requirement	56,215	250,627	449, 456, 565	56,215	250,627
4	2022 KY Major Storm Deferral	13,838,283		131	13,838,283	
5	2022 PJM Annual Transmission Requirement		41,814	449, 456, 565	41,814	
6	Big Sandy Recovery Over/Under, Kentucky PSC Case No. 2014-00396	(60,619,577)	60,707,489	131, 407	96,879	(8,967)
7	Big Sandy Retirement Rider Unit 2 O&M, Kentucky PSC Case No. 2014-00396	948,896	8,522	131, 407	951,292	6,126
8	BS1OR Under Recovery, Kentucky PSC Case No. 2014-00396		583,093	182, 407	583,093	
9	CCS FEED Study Costs, Kentucky PSC Case No. 2014-00396	541,172		506	34,914	506,258
10	Cost of Removal-Big Sandy Coal, Kentucky PSC Case No. 2014-00396	(25,092,327)	25,092,327	0		
11	Deferred Depreciation - Environmental, Kentucky PSC Case No. 2014-00396	5,147,803	5,358,798	403	5,165,221	5,341,380
12	Depreciation Expense - Hanging Rock/Jefferson 765 KV Line, Amortization Period: 12/1984 - 11/2032	41,233		182, 406	5,208	36,025
13	Demand Side Management Programs	24,026	1,434,368	254, 456, 908	1,458,394	
14	IGCC Pre-Construction Costs, Kentucky PSC Case No. 2014-00396, Amortization Period: 07/2015 - 06/2040	825,378		506	53,250	772,128
15	KY Under-Recovered PPA Rider	57,372,610	5,763,175	566, 131	63,135,785	
16	M&S - Retiring Plants, Kentucky PSC Case No. 2014-00396	3,015,785		131	3,015,785	
17	NBV - AROs Retired Plants, Kentucky PSC Case No. 2014-00396	52,294,384	26,763,845	182	24,323,106	54,735,123
18	NERC Compliance and Cybersecurity Costs, Kentucky PSC Case No. 2014-00396	3,205,090	1,068,617	182, 431, 404	614,833	3,658,874
19	Unrealized Loss on Forward Commitments Regulated Assets/Liabilities	7,877	64,888	175, 244, 254, 256, 456	68,875	3,890
20	OSS Margin Sharing, Kentucky PSC Case No. 2017-00179	1,867,242		561	1,867,242	
21	Rockport Offset/Kentucky Securitization	5,639,218	471,417,413	182, 440, 442	477,056,631	
22	Post In-Service AFUDC Hanging Rock/Jefferson 765 KV Line, Amortization Period: 12/1984 - 11/2032	264,744		182, 406	33,408	231,336
23	Rate Cases Expenses	640,661	894,122	928	314,000	1,220,783
24	Rockport Capacity Deferral, Kentucky PSC Case No. 2017-00179	45,010,718	6,993,136	131, 182, 431, 555	52,003,854	
25	SFAS 109 Deferred FIT	44,910,256	34,298,185	190, 236, 254, 282, 283, 409, 410, 411	34,069,688	45,138,753
26	SFAS 109 Deferred SIT	101,146,637	79,175,841	283	79,474,043	100,848,435
27	SFAS 112 Post Employment Benefit	2,430,971	495,772	228, 242	142,676	2,784,067
28	SFAS 158 Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans	13,726,049	27,200,399	129, 228	33,325,638	7,600,810
29	Spent AROs - Big Sandy Coal, Kentucky PSC Case No. 2014-00396	110,510,521	401,645	131, 182	110,618,281	293,885
30	Unrecovered Fuel Cost	8,634,580	7,505,937	501	12,643,084	3,497,433
31	Unrecovered Plant - Big Sandy, Kentucky PSC Case No. 2014-00396	256,509,062		131	256,509,062	
32	2023 PJM Annual Transmission Requirement	482,592	34,856	447	517,458	(10)
33	2023 Kentucky Storm Deferral	8,415,089		131	8,415,089	
34	KY Deferred Securitization Exp	2,267,123	498,346,758	182	472,833,059	27,780,822

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)	
35	Deferred NOLC Equity Carrying Charges	(4,360,996)		182	4,544,232	(8,905,228)
36	BSDR Deferred Carrying Charges	17,244,859	8,972,063	131,182,431	26,211,021	5,901
37	BSDR Deferred Equity Carrying Charges	(7,135,402)	10,845,330	131,182,431	3,712,370	(2,442)
38	Deferred NOLC Carrying Charges	4,360,996	4,544,232			8,905,228
39	2024 PJM Annual Transmission Requirement	70,856	48,864	449,456,565	71,970	47,750
40	2024 Kentucky Storm Deferral	10,783,447	39,138	593	796,657	10,025,928
41	2025 PJM Annual Transmission Requirement		12,699	449,456,565	12,699	
42	2025 Kentucky Storm Deferral		22,661,464	593	11,024,115	11,637,349
43	KY Deferred PJM Trans Costs		32,619,456	565	18,767,650	13,851,806
44	TOTAL	731,531,918	1,333,644,873		1,774,912,721	290,264,071

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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	Deferred Property Tax	20,916,634	19,899,666	107/236/408	19,402,596	21,413,704
2	Agency Fees - Factored A/R	1,070,851	14,615,261	142/173/184/426	14,392,189	1,293,923
3	Unamortized Credit Line Fees, Amortized thru March 2027	502,804	6,145	431	179,003	329,946
4	Miscellaneous Items	(6,853)	355,200	142/456/593	338,146	10,201
5	Trnsrce OU Acctg for Def Asset	29,698	115,364	253/565	112,519	32,543
6	PJM Transmission True-up	8,493,281	16,406,335	186/253/456/565	21,430,608	3,469,008
7	Deferred Expenses - Current	184	170,325	926/930	168,937	1,572
47	Miscellaneous Work in Progress	110,270				98,076
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	31,116,869				26,648,973

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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	PT Repairs UOP - NORM	6,268,043	6,726,907
3	ACCRUED BK PENSION EXPENSE	(2,769,455)	(3,278,017)
4	NOL-STATE C/F-DEF TAX ASSET-L/T - KY	16,474,882	18,403,141
5	ACCRD BOOK ARO EXPENSE - SFAS 143	17,671,086	18,338,937
6	ACCRD SFAS 106 PST RETIRE EXP	(4,873,718)	(7,119,923)
7	Other	(563,751)	5,936,471
8	TOTAL Electric (Enter Total of lines 2 thru 7)	32,207,087	39,007,516
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	49,926,129	43,085,930
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	82,133,216	82,093,446
Notes			

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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	<input type="checkbox"/> A Resubmission		

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		2,000,000	50.00		1,009,000	50,450,000				
6	Total	2,000,000			1,009,000	50,450,000				
7	Preferred Stock (Account 204)									
8										
9										
10										
11	Total									

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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	523,324,094
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	523,324,094
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	2,745,424
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	1,050,034
16	Ending Balance Amount	3,795,458
17	Other Paid in Capital	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	527,119,552

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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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		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	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													
3													
4													
5	Subtotal												
6	Reacquired Bonds (Account 222)												
7													
8													
9													
10	Subtotal												
11	Advances from Associated Companies (Account 223)												
12													
13													
14													
15	Subtotal												
16	Other Long Term Debt (Account 224)												
17	Senior Unsecured Notes - 5.625%, Series D		75,000,000					06/13/2003	12/01/2032	06/13/2003	12/01/2032	75,000,000	4,218,750
18	Senior Unsecured Notes - 8.030%		30,000,000					06/18/2009	06/18/2029	06/18/2009	06/18/2029	30,000,000	2,409,000
19	Senior Unsecured Notes - 8.130%		60,000,000					06/18/2009	06/18/2039	06/18/2009	06/18/2039	60,000,000	4,878,000
20	Senior Unsecured Notes - 4.180%, Series A		120,000,000					09/30/2014	09/30/2026	09/30/2014	09/30/2026	120,000,000	5,016,000
21	Senior Unsecured Notes - 4.33%, Series B		80,000,000					12/30/2014	12/30/2026	12/30/2014	12/30/2026	80,000,000	3,464,000
22	Senior Unsecured Notes - 3.35%, Series G		40,000,000					09/12/2017	09/12/2027	09/12/2017	09/12/2027	40,000,000	1,340,000
23	Senior Unsecured Notes - 3.45%, Series H		165,000,000					09/12/2017	09/12/2029	09/12/2017	09/12/2029	165,000,000	5,692,500
24	Senior Unsecured Notes - 4.12%, Series I		55,000,000					09/12/2017	09/12/2047	09/12/2017	09/12/2047	55,000,000	2,266,000

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)
25	Senior Unsecured Notes - 7.00%, Series JState Commission Authority Case No. 2023-00029		375,000,000		3,081,116		671,250	11/10/2023	11/15/2033	11/10/2023	11/15/2033	375,000,000	26,250,000
26	West Virginia Economic Development Authority Mitchell Project Series 2014A State Commission Authority Case# 2013-00410 Maturity Extended to 6/17/2026		65,000,000					06/26/2014	04/01/2036	06/26/2014	06/17/2026	65,000,000	3,055,000
27	Term Loan - KY State Commission Authority: Case No. 2021-00131 Maturity Extended to 6/30/2025		150,000,000					06/17/2021	06/30/2024	06/17/2021	06/30/2024		3,627,630
28								06/30/2024	06/30/2025	06/30/2024	06/30/2025		
29	Term Loan - KY State Commission Authority: Case No. 2024-00017		150,000,000					01/02/2025	02/01/2026	01/02/2025	06/12/2025		3,555,746
29	Subtotal		1,365,000,000		3,081,116		671,250					1,065,000,000	65,772,626
33	TOTAL		1,365,000,000	8,609,062								1,065,000,000	65,772,626

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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)	40,796,226
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	(23,764,736)
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
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44		

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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	
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Included in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)
1	Pers Prop Leased	Property Tax	KY		952,353.00	0.00	143,467.00	34,550.00		1,061,270.00	0.00
2	Pers Prop Leased	Property Tax	WV		0.00	0.00	0.00	0.00		0.00	0.00
3	Real & Pers Prop	Property Tax	KY		34,425,567.00	0.00	16,462,343.00	17,150,600.00		33,737,310.00	0.00
4	Real & Pers Prop	Property Tax	WV		4,583,004.00	0.00	2,935,339.00	3,035,053.00		4,483,290.00	0.00
5	Real Prop Leased	Property Tax	KY		0.00	0.00	14,146.00	14,146.00		0.00	0.00
6	Unemployment Tax	Unemployment Tax	KY		2,166.00	0.00	11,270.00	10,736.00		2,700.00	0.00
7	Unemployment Tax	Unemployment Tax	OH		27.00	0.00	0.00	27.00		0.00	0.00
8	Unemployment Tax	Unemployment Tax	WV		297.00	0.00	615.00	751.00		161.00	0.00
9	Unemployment Tax	Unemployment Tax	(blank)		4,546.00	0.00	13,579.00	13,314.00		4,811.00	0.00
10	Sales Tax	Sales And Use Tax	KY		0.00	327,284.00	0.00	23,359.00		0.00	350,643.00
11	Use Tax	Sales And Use Tax	KY		109,764.00	70,340.00	1,585,048.00	1,584,027.00		104,472.00	64,027.00
12	Use Tax	Sales And Use Tax	WV		1,621.00	0.00	64,390.00	64,520.00		1,491.00	0.00
13	City Tax	Income Tax			(49,346.00)	0.00	0.00	0.00		(49,346.00)	0.00
14	Federal Income	Income Tax			2,190,909.00	0.00	(5,709,540.00)	3,059,872.00		(6,578,503.00)	0.00
15	State Income Tax	Income Tax	IL		17,323.00	0.00	(12,788.00)	0.00		4,535.00	0.00
16	State Income Tax	Income Tax	KY		(730,321.00)	0.00	(2,277,411.00)	815,501.00		(3,823,233.00)	0.00
17	State Income Tax	Income Tax	MI		0.00	0.00	(176.00)	0.00		(176.00)	0.00
18	State Income Tax	Income Tax	MULTI		(360,769.00)	0.00	0.00	0.00		(360,769.00)	0.00
19	State Income Tax	Income Tax	NY		0.00	0.00	2,067.00	0.00		2,067.00	0.00
20	State Income Tax	Income Tax	WI		0.00	0.00	(50.00)	0.00		(50.00)	0.00
21	State Income Tax	Income Tax	WV		1,311,672.00	0.00	(843,009.00)	0.00		468,663.00	0.00
22	State Income Tax FIN48	Income Tax	FIN48		0.00	0.00	0.00	0.00		0.00	0.00
23	Excise Tax	Fuel Tax			0.00	0.00	11,049.00	11,049.00		0.00	0.00
24	Federal Insurance Tax	Federal Insurance Tax	(blank)		167,814.00	0.00	2,799,194.00	2,686,080.00		280,928.00	0.00
25	State Franchise	Franchise Tax	KY		240,585.00	0.00	0.00	0.00		240,585.00	0.00
26	Ohio CAT Tax	Other State Tax	OH		0.00	0.00	130.00	130.00		0.00	0.00
27	Utility Gr Lic - EDP	Other State Tax	KY		1,649.00	0.00	18,494.00	18,602.00		1,541.00	0.00
28	Muni License Fee	Other State Tax	KY		(25.00)	0.00	0.00	25.00		(50.00)	0.00
29	Muni License Fee	Other State Tax	WV		(20.00)	0.00	0.00	20.00		(40.00)	0.00
30	WV Business & Occupation	Other Property Tax	WV		614,137.00	0.00	5,264,683.00	5,291,762.00		587,058.00	0.00
40	TOTAL				43,482,953.00	397,624.00	20,482,840.00	33,814,124.00		30,168,715.00	414,670.00

DISTRIBUTION OF TAXES CHARGED

Line No.	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	143,468.00			0.00
2	1,730.00			(1,730.00)
3	14,482,644.00			1,979,700.00
4	3,342,385.00			(407,046.00)
5	14,146.00			0.00
6	2,232.00			9,039.00
7	0.00			0.00
8	13,369.00			(12,754.00)
9	8,851.00			4,729.00
10	0.00			0.00
11	55,178.00			1,529,869.00
12	43.00			64,348.00
13	0.00			0.00
14	(3,065,176.00)			(2,644,364.00)
15	(8,596.00)			(4,191.00)
16	150,555.00			(2,427,966.00)
17	26.00			(203.00)
18	0.00			0.00
19	0.00			2,067.00
20	0.00			(50.00)
21	8,628.00			(851,638.00)
22	0.00			0.00
23	11,049.00			0.00
24	2,036,431.00			764,762.00
25	0.00			0.00
26	130.00			0.00
27	18,494.00			0.00
28	0.00			0.00
29	0.00			0.00
30	5,286,299.00			(21,616.00)
40	22,501,885.00			(2,017,044.00)

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

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%		411.1		411.4					
8	TOTAL Electric (Enter Total of lines 2 thru 7)									
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										
47	OTHER TOTAL									
48	GRAND TOTAL									

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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	TV Pole Attachments	135,288	186/454	877,331	902,103	160,060
2	Customer Advance Receipts	2,486,968	142	2,486,968	2,168,851	2,168,851
3	Deferred Gain: Fiber Optic Agrmts-In Kind SvcAmortize through June 2026	25,890	124/411	16,506		9,384
4	Deferred Revenue Fiber Optic Lines-Sold-Defd Rev Amortize through January 2025	74	451	74		
5	PJM Transmission True-up	8,191,204	449/229/186/565	11,289,403	12,189,251	9,091,052
6	Contribution Aid of Construction	447,138	107/108	447,138	184,749	184,749
7	Deferred Credits	63,453	142/143	63,453	20,959	20,959
8	Legal Contingencies	(671)	921	2,801	3,472	
9	Kentucky Securitization		456	227,604	16,157,466	15,929,862
10	NERC Penalties	72,870	242	24,401	27,946	76,415
11	Make Ready Advance				171,497	171,497
47	TOTAL	11,422,215		15,435,679	31,826,294	27,812,829

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	(2) <input type="checkbox"/> A Resubmission		

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 relating 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	39,140,758	93,464	2,086,272							37,147,950
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	39,140,758	93,464	2,086,272							37,147,950
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	OTHER	(15,502,878)					254	28,864	254	550,757	(14,980,985)
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	23,637,880	93,464	2,086,272				28,864		550,757	22,166,965
18	Classification of TOTAL										
19	Federal Income Tax	23,637,880	93,464	2,086,272				28,864		550,757	22,166,965
20	State Income Tax										
21	Local Income Tax										

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	(2) <input type="checkbox"/> A Resubmission		

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating 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	323,806,151	45,589,125	39,010,793					—		330,384,483
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	323,806,151	45,589,125	39,010,793							330,384,483
6	Others	(36,254,466)				1823/254	7,040,506	1823/254	10,235,583		(33,059,389)
9	TOTAL Account 282 (Total of Lines 5 thru 8)	287,551,685	45,589,125	39,010,793			7,040,506		10,235,583		297,325,094
10	Classification of TOTAL										
11	Federal Income Tax	287,551,685	45,589,125	39,010,793			7,040,506		10,235,583		297,325,094
12	State Income Tax										
13	Local Income Tax										

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		

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	Deferred Fuel Costs	1,813,261	2,889,159	2,889,159							1,813,261
4	REG ASSET - Big Sandy Retirement	60,999,330	18,095,978	77,308,739							1,786,569
5	REG ASSET-ROCKPORT CAPACITY DEFERRAL	6,393,115		8,325,204							(1,932,089)
6	Reg Asset - KY Storms	16,539,436		16,539,436							
7	Reg Asset - PPA Rider	12,048,249	188,122	12,236,370							1
8	Reg Asset - Decomm Rider		98,111,567	1,154,427							96,957,140
9	Other	24,377,916	153,421,910	145,382,239							32,417,587
9	TOTAL Electric (Total of lines 3 thru 8)	122,171,307	272,706,736	263,835,574							131,042,469
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	132,789,619					1823/254	98,739,154	1823/254	92,187,319	126,237,784
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	254,960,926	272,706,736	263,835,574				98,739,154		92,187,319	257,280,253
20	Classification of TOTAL										
21	Federal Income Tax	152,570,337	272,706,736	263,835,574				17,385,654		13,279,619	157,335,464
22	State Income Tax	102,390,589						81,353,500		78,907,700	99,944,789
23	Local Income Tax										

NOTES

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

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	Capacity Charge Tariff OverRec	366,131	407	366,131		
2	Home Energy Assistance Program	1,190,854	182, 440, 442, 444	2,182,621	1,923,643	931,876
3	Kentucky Reliability	636,006	593	1,836,228	1,806,513	606,291
4	KY - DSM Over Recovery		182	112,378	615,857	503,479
5	OSS Margin Sharing		440, 442, 444	1,576,051	3,445,235	1,869,184
6	PJM Trans Enhancement Reg Liability	751,225	142	751,225		
7	SFAS 109 Deferred FIT	114,950,743	190, 282, 283	16,001,706	6,459,109	105,408,146
8	Steam Maintenance Levelized Reg Liability, KY Case No. 2017-00179	1,426,702	512	699,253		727,449
9	Unrealized Gain on Forward Commitments	844,396	182	1,619,879	5,368,713	4,593,230
10	KY Over-recovered PPA Rider				2,040,429	2,040,429
11	Tariff FTC		407	1,825	1,699,119	1,697,294
12	Securitized Bond Deferral				255,128	255,128
13	FAS 109 Deferred State Income Tax			55,678	5,523,236	5,467,558
41	TOTAL	120,166,057		25,202,975	29,136,981	124,100,064

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Electric Operating Revenues

- 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.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- 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.
- 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.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.
- 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.)
- See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
- For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
- 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	308,068,570	279,997,957	1,931,253	1,858,160	130,322	130,852
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	195,649,920	190,932,900	1,421,636	1,438,141	30,304	30,391
5	Large (or Ind.) (See Instr. 4)	161,929,391	167,644,587	1,917,023	2,016,139	927	958
6	(444) Public Street and Highway Lighting	2,028,719	2,140,814	7,692	8,838	294	306
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	667,676,600	640,716,258	5,277,604	5,321,277	161,848	162,507
11	(447) Sales for Resale	34,395,300	23,862,331	609,465	465,216	3	5
12	TOTAL Sales of Electricity	702,071,900	664,578,589	5,887,069	5,786,493	161,851	162,512
13	(Less) (449.1) Provision for Rate Refunds	2,813,096	6,446,586				
14	TOTAL Revenues Before Prov. for Refunds	699,258,804	658,132,003	5,887,069	5,786,493	161,851	162,512
15	Other Operating Revenues						
16	(450) Forfeited Discounts	1,454,892	866,468				
17	(451) Miscellaneous Service Revenues	75,050	123,252				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	9,734,464	9,447,705				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	2,366,813	1,047,884				
22	(456.1) Revenues from Transmission of Electricity of Others	51,861,452	36,965,056				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	65,492,671	48,450,365				
27	TOTAL Electric Operating Revenues	764,751,475	706,582,368				

Line12, column (b) includes \$ 3,923,988 of unbilled revenues.

Line12, column (d) includes 37,836 MWH relating to unbilled revenues

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

(a) Concept: SalesToUltimateConsumers

Detail of Unmetered Sales - 2025

	Revenue	MWH	Average No. of Customers
Residential	6,018,129	18,020	38,580
Commercial	3,442,657	12,399	7,236
Industrial	146,922	589	180
Public Street Lighting	45,672	104	43
Total	9,653,380	31,112	46,039

(b) Concept: SalesToUltimateConsumers

Detail of Unmetered Sales - 2024

	Revenue	MWH	Average No. of Customers
Residential	5,871,038	19,508	38,800
Commercial	3,223,094	13,068	7,213
Industrial	139,228	627	182
Public Street Lighting	42,593	104	44
Total	9,275,953	33,307	46,239

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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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					
3					
4					
5					
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41					
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43					
44					
45					
46	TOTAL				

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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						
2						
3						
4						
5						
6						
7						
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35						
36						
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38						
39						
40						
41	TOTAL Billed Residential Sales					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	1,931,253	308,068,570		130,322	

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

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						
2						
3						
4						
5						
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35						
36						
37						
38						
39						
40						
41	TOTAL Billed Small or Commercial					
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)					
43	TOTAL Small or Commercial	1,421,636	195,649,920	30,304		

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	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						
2						
3						
4						
5						
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35						
36						
37						
38						
39						
40						
41	TOTAL Billed Large (or Ind.) Sales					
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)					
43	TOTAL Large (or Ind.)	1,917,023	161,929,391	927		

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	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						
2						
3						
4						
5						
6						
7						
8						
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37						
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39						
40						
41	TOTAL Billed Public Street and Highway Lighting					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL	7,692	2,028,719		294	

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
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31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		2,813,096			

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> 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						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
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28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed - All Accounts					
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts					
43	TOTAL - All Accounts					

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	(2) <input type="checkbox"/> 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	CITY OF OLIVE HILL	RQ	KPCO 52				9,043	381,638	781,999		1,163,637
2	CITY OF VANCEBURG	RQ	KPCO 51				23,098	943,416	1,844,856		2,788,272
3	PJM INTERCONNECTION	OS	NOTE 1				577,324	(50,881)	31,620,144		31,569,263
4	PJM TRANSMISSION FOR RQ CUSTOMERS	RQ	VARIOUS				0			(1,122,167)	(1,122,167)
5	WELLS FARGO SECURITIES, LLC	OS	NOTE 1				0		(3,705)		(3,705)
15	Subtotal - RQ						32,141	1,325,054	2,626,855	(1,122,167)	2,829,742
16	Subtotal-Non-RQ						577,324	(50,881)	31,616,439		31,565,558
17	Total						609,465	1,274,173	34,243,294	(1,122,167)	34,395,300

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	4,503,104	4,426,925
5	(501) Fuel	145,595,492	135,378,424
6	(502) Steam Expenses	5,340,960	5,053,243
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	75,043	44,420
10	(506) Miscellaneous Steam Power Expenses	5,057,671	6,265,855
11	(507) Rents	2,318	
12	(509) Allowances	(140,363)	81,225
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	160,434,225	151,250,092
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	992,052	1,677,430
16	(511) Maintenance of Structures	1,692,880	1,794,464
17	(512) Maintenance of Boiler Plant	11,839,446	13,481,479
18	(513) Maintenance of Electric Plant	5,906,114	3,949,152
18.1	(513.1) Maintenance of Computer Hardware		
18.2	(513.2) Maintenance of Computer Software	55,265	
18.3	(513.3) Maintenance of Communication Equipment	5,682	
19	(514) Maintenance of Miscellaneous Steam Plant	1,482,543	1,535,471
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	21,973,982	22,437,996
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	182,408,207	173,688,088
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	77	
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)	77	
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 & 40)	77	
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		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
56.1	(544.1) Maintenance of Computer Hardware		
56.2	(544.2) Maintenance of Computer Software		
56.3	(544.3) Maintenance of Communication Equipment		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of Lines 62 thru 67)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
71.1	(553.1) Maintenance of Computer Hardware		
71.2	(553.2) Maintenance of Computer Software		
71.3	(553.3) Maintenance of Communication Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	142,297,066	107,599,231
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	54,083	69,875
78	(557) Other Expenses	811,430	799,007
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	143,162,579	108,468,113
79.1	F. Solar Generation		
79.2	Operation		
79.3	(558.1) Operation Supervision and Engineering	1,405	
79.4	(558.2) Solar Panel Generation and Other Plant Operating Expenses	2	
79.6	(558.4) Rents		
79.7	TOTAL Operation (Enter Total of lines 79.3 thru 79.6)	1,407	
79.8	Maintenance		
79.9	(558.6) Maintenance Supervision and Engineering		
79.10	(558.7) Maintenance of Solar Panels, Structures, and Equipment	3	

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		
79.13	(558.10) Maintenance of Communication Equipment		
79.14	(558.11) Maintenance of Miscellaneous Solar Generation Plant		
79.15	TOTAL Maintenance (Enter Total of lines 79.9 thru 79.14)	3	
79.16	TOTAL Power Production Expenses-Solar (total of lines 79.7 & 79.15)	1,410	
79.17	G. Wind Generation		
79.18	Operation		
79.19	(558.13) Operation Supervision and Engineering	9,513	
79.20	(558.14) Wind Turbine Generation and Other Plant Operating Expenses	514	
79.21	(558.16) Rents	24	
79.22	TOTAL Operation (Enter Total of lines 79.19 thru 79.21)	10,051	
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)	10,051	
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)	325,582,324	282,156,201
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,544,724	2,064,772
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	695,071	386,085
87	(561.3) Load Dispatch-Transmission Service and Scheduling	(109)	130
88	(561.4) Scheduling, System Control and Dispatch Services	1,411,272	1,396,897
89	(561.5) Reliability, Planning and Standards Development	107,673	78,081
90	(561.6) Transmission Service Studies	4	
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	408,877	452,211
93	(562) Station Expenses	359,292	203,497
94	(563) Overhead Lines Expenses	31,418	27,183
95	(564) Underground Lines Expenses		16
96	(565) Transmission of Electricity by Others	86,595,549	78,574,635

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
97	(566) Miscellaneous Transmission Expenses	1,119,565	2,447,476
98	(567) Rents	2,035	
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	93,275,371	85,630,983
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	5,939	22,224
102	(569) Maintenance of Structures	34,765	32,286
103	(569.1) Maintenance of Computer Hardware	2,246	7,901
104	(569.2) Maintenance of Computer Software	120,595	223,926
105	(569.3) Maintenance of Communication Equipment	1,110	7,739
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	610,432	461,398
108	(571) Maintenance of Overhead Lines	6,270,374	5,005,477
109	(572) Maintenance of Underground Lines	42	316
110	(573) Maintenance of Miscellaneous Transmission Plant	20,124	2,918
111	TOTAL Maintenance (Total of Lines 101 thru 110)	7,065,627	5,764,185
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	100,340,998	91,395,168
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	1,392,419	1,442,994
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,392,419	1,442,994
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	1,392,419	1,442,994
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		
131.14	(578.6) Maintenance of Miscellaneous Other Energy Storage Plant		
131.15	Total Maintenance (Lines 131.9 thru 131.14)		
131.16	TOTAL Energy Storage Expenses (Total of 131.7 and 131.15)		
132	5. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	434,485	1,192,931
135	(581) Load Dispatching	2,753	1,048

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
136	(582) Station Expenses	405,770	387,429
137	(583) Overhead Line Expenses	1,257,348	281,948
138	(584) Underground Line Expenses	337,011	326,743
139	(585) Street Lighting and Signal System Expenses	23,200	40,246
140	(586) Meter Expenses	1,344,319	1,353,435
141	(587) Customer Installations Expenses	200,099	191,956
142	(588) Miscellaneous Expenses	3,374,529	6,285,823
143	(589) Rents	1,070,318	1,048,358
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	8,449,832	11,109,917
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	117,895	15,594
147	(591) Maintenance of Structures	13,459	10,318
148	(592) Maintenance of Station Equipment	518,780	888,071
148.1	(592.2) Maintenance of Computer Hardware		
148.2	(592.3) Maintenance of Computer Software	139,468	
148.3	(592.4) Maintenance of Communication Equipment	1,172,297	
149	(593) Maintenance of Overhead Lines	33,601,170	31,281,486
150	(594) Maintenance of Underground Lines	69,785	24,176
151	(595) Maintenance of Line Transformers	6,784	16,734
152	(596) Maintenance of Street Lighting and Signal Systems	4,722	9,850
153	(597) Maintenance of Meters	39,049	37,643
154	(598) Maintenance of Miscellaneous Distribution Plant	22,581	27,046
155	TOTAL Maintenance (Total of Lines 146 thru 154)	35,705,990	32,310,918
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	44,155,823	43,420,835
157	6. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	22,667	13,540
160	(902) Meter Reading Expenses	510,062	346,932
161	(903) Customer Records and Collection Expenses	4,795,149	4,846,162
162	(904) Uncollectible Accounts	(1,274)	20,263
163	(905) Miscellaneous Customer Accounts Expenses	26,018	19,916
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	5,352,622	5,246,813
165	7. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	40,292	51,153
168	(908) Customer Assistance Expenses	2,465,555	1,687,407
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	32,012	14,382
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	2,537,859	1,752,942
172	8. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	16,664	11,031
176	(913) Advertising Expenses		80
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	16,664	11,111
179	9. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	11,365,042	12,245,270
182	(921) Office Supplies and Expenses	1,263,533	516,549
183	(Less) (922) Administrative Expenses Transferred-Credit	1,220,819	1,824,875
184	(923) Outside Services Employed	2,166,306	6,729,133
185	(924) Property Insurance	1,076,385	1,092,472
186	(925) Injuries and Damages	2,308,171	2,264,769
187	(926) Employee Pensions and Benefits	(330,984)	127,663

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
188	(927) Franchise Requirements	163,722	162,329
189	(928) Regulatory Commission Expenses	3,489,509	3,992,821
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	103,224	119,861
192	(930.2) Miscellaneous General Expenses	728,354	760,593
193	(931) Rents	57,275	69,999
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	21,169,718	26,256,584
195	Maintenance		
196	(935) Maintenance of General Plant	449,476	3,157,747
196.1	(935.1) Maintenance of Computer Hardware	16,137	
196.2	(935.2) Maintenance of Computer Software	836,978	
196.3	(935.3) Maintenance of Communication Equipment	110,859	
196.4	TOTAL Maintenance (Enter Total of lines 196 thru 196.3)	1,413,450	3,157,747
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196.4)	22,583,168	29,414,331
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 131.16, 156, 164, 171, 178, and 197)	501,961,877	454,840,394

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Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> 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 schedule 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 megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
- 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) Settlement (\$) (n)	
1	PJM INTERCONNECTION	OS					3,133,926					227,590	140,680,756		140,908,3
2	Evolution Markets Futures, LLC	OS					0						2,883		2,8
3	Wells Fargo Securities, LLC	OS					0						(463,686)		(463,68
4	GRIDFLEX(ROCKLAND) GENERATION	OS					0					657,000			657,0
5	OMNIS PLEASANTS	OS					0					1,192,523			1,192,5
15	TOTAL						3,133,926	0	0	0	0	2,077,113	140,219,953		142,297,0

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	(2) <input type="checkbox"/> 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	East Kentucky Power Cooperative	Various	Various	OLF	PJM OATT	Various	Various							55,280	55,280
2	PJM Network Integ Rev - Affil	Various	Various	FNO	PJM OATT	Various	Various				31,412,143				31,412,143
3	PJM Network Integ Trans Rev Whlsle	Various	Various	FNO	PJM OATT	Various	Various				2,956,535				2,956,535
4	PJM Network Integ Trans Serv	Various	Various	FNO	PJM OATT	Various	Various				12,052,582				12,052,582
5	PJM Point to Point Trans Service	Various	Various	LFP	PJM OATT	Various	Various				2,582,262				2,582,262
6	PJM Power Factor Credits Rev Whlsle	Various	Various	OS	PJM OATT	Various	Various							956	956
7	PJM Trans Enhancement Rev	Various	Various	FNO	PJM OATT	Various	Various				1,893,579				1,893,579
8	PJM Trans Enhancement Rev - Affil	Various	Various	FNO	PJM OATT	Various	Various				575,524				575,524
9	PJM Trans Enhancement Rev Whlsle	Various	Various	FNO	PJM OATT	Various	Various				54,592				54,592
10	PJM Trans Owner Admin Revenue	Various	Various	OLF	PJM OATT	Various	Various					94,596			94,596
11	PJM Trans Owner Serv - Affil	Various	Various	OLF	PJM OATT	Various	Various					104,871			104,871
12	PJM Trans Owner Serv Rev Whlsle	Various	Various	OLF	PJM OATT	Various	Various					6,861			6,861
13	PJM Non-Aff Gen IPP Revenue	Various	Various	OS	PJM OATT	Various	Various							22,332	22,332

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)
14	PJM Power Factor Credits Rev Nonaffiliated	Various	Various	OS	PJM OATT	Various	Various						3,895	3,895
15	PJM Trans Distribution & Metering	Various	Various	OS	PJM OATT	Various	Various						45,444	45,444
35	TOTAL										51,527,218	206,328	127,906	51,861,452

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Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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36					
37					
38					
39					
40					
41					
42					
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: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> 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	Concurrent Energy	LFP					102,906	102,906
2	PJM - Enhancements	OS					6,806,583	6,806,583
3	PJM - Trans Owner	OS					166,086	166,086
4	PJM - NITS	OS					79,519,974	79,519,974
	TOTAL						86,595,549	86,595,549

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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	92,667
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	18
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	Associated Business Development	289,910
7	AEP Service Corporation Billings	114,222
8	Intercompany Allocations	77,535
9	Corporate Money Pool Allocations	42,332
10	Corporate and Fiscal	98,376
11	Miscellaneous	13,294
46	TOTAL	728,354

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

- Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
- Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
- Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
- If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant					
2	Steam Production Plant	36,246,292	1,868,242			38,114,534
3	Nuclear Production Plant					
4	Hydraulic Production Plant- Conventional					
5	Hydraulic Production Plant- Pumped Storage					
5.1	Solar Production Plant					
5.2	Wind Production Plant					
5.3	Other Renewable Production Plant					
6	Other Production Plant					
7	Transmission Plant	27,400,103				27,400,103
8	Distribution Plant	43,130,460				43,130,460
9	Regional Transmission and Market Operation					
9.1	Energy Storage Plant					
10	General Plant	14,106,740	6,985			14,113,725
11	Common Plant-Electric					
12	TOTAL	120,883,595	1,875,227			122,758,822

B. Basis for Amortization Charges

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM -- COAL/LIGNITE						
13	311 - Big Sandy	24.979					
14	311 - Mitchell	81.675					
15	312 - Big Sandy	87.014					
16	312 - Mitchell	882.054					
17	312 - Mitchell SCR	9.345					
18	314 - Big Sandy	64.452					
19	314 - Mitchell	56.334					
20	315 - Big Sandy	8.434					
21	315 - Mitchell	26.014					
22	315.1	0.041					
23	315.3	0.137					
24	316 - Big Sandy	4.421					
25	316 - Mitchell	9.887					
26	TOTAL COAL/LIGNITE	1,254.787					
27	TRANSMISSION						
28	350.1	40.258					
29	351.2	2.382					
30	351.3	0.566					
31	352	32.684					
32	352 - Big Sandy	0.01					
33	352 - Mitchell	0.072					
34	353	297.4					
35	353 - Big Sandy	0.603					
36	353 - Mitchell	12.303					
37	353.16	8.929					
38	354	126.738					
39	355	264.142					
40	356	180.514					
41	356.16	9.74					
42	357	6.345					
43	358	0.106					
44	358.16	0.514					
45	TOTAL TRANSMISSION	983.306					
46	DISTRIBUTION						
47	360.1	6.537					
48	361	20.135					

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		

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	Kentucky IRP Plan		40,027	40,027		Electric	928	40,027				
2	Kentucky PSC Investigation		79,526	79,526		Electric	928	79,526				
3	EL25-67 KPSC Complaint		80,630	80,630		Electric	928	80,630				
4	2023 KYP Base Rate Case Filing		369,617	369,617	640,661	Electric	928	55,617		928	314,000	326,661
5	2024 Big Sandy KY Securitization		108,497	108,497		Electric	928	108,497				
6	KPSC Annual Fee	1,010,268		1,010,268		Electric	928	1,010,268				
7	2024 Kentucky Power Base Rate Case		1,673,300	1,673,300		Electric	928	2,567,422	894,122			894,122
8	Minor Items < \$25,000		127,643	127,643		Electric	928	127,643				
46	TOTAL	1,010,268	2,479,240	3,489,508	640,661			4,069,630	894,122		314,000	1,220,783

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	(2) <input type="checkbox"/> 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

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.

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

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(1)b: Generation: Fossil-Fuel Steam	Generation Asset Management					
2		2 items under \$50,000	1,374		506	1,374	
3	A(1)e: Generation: Unconventional	1 item under \$50,000					
4	A(2): Transmission	1 item under \$50,000	767		566	767	
5	A(3): Distribution	1 items under \$50,000	658		588	658	
6	A(5): Environment (other than equipment)	1 items under \$50,000					
7	A(6): Other	2 items under \$50,000	(128)		506,566,588	(128)	
8	A(6)a: Alternate Energy	1 item under \$50,000					
9	A(6)f: Other (Metering)	1 item under \$50,000	31		588	31	
10	A(6)g: Other (program management)	1 item under \$50,000	445		566,588	445	
11	A(7) TOTAL COST INCURRED INTERNALLY		3,148			3,148	
12	B: Electric R&D External	2 items under \$50,000		623	566,588	623	
13	B(1): R&D support to the Research Council						
14	or the Electric Power Research	EPRI Research Portfolio		99,360	506,566,588	99,360	
15		EPRI Environmental Science		11,723	506	11,723	
16	Institute	9 items under \$50,000		11,413	506,566,588	11,413	
17	B(4): Research Support to Others	1 items under \$50,000		38	506,566	38	
18	B(5) TOTAL COST INCURRED EXTERNALLY			123,157		123,157	

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> 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	8,497,480		
4	Transmission	4,483		
5	Regional Market			
5.1	Energy Storage			
6	Distribution	3,333,850		
7	Customer Accounts	776,762		
8	Customer Service and Informational	213,957		
9	Sales			
10	Administrative and General	2,754,701		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	15,581,233		
12	Maintenance			
13	Production	4,181,909		
14	Transmission	13,624		
15	Regional Market			
15.1	Energy Storage			
16	Distribution	6,680,579		
17	Administrative and General	669,176		
18	TOTAL Maintenance (Total of lines 13 thru 17)	11,545,288		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	12,679,389		
21	Transmission (Enter Total of lines 4 and 14)	18,107		
22	Regional Market (Enter Total of Lines 5 and 15)			
22.1	Energy Storage (Enter Total of Lines 5.1 and 15.1)			
23	Distribution (Enter Total of lines 6 and 16)	10,014,429		
24	Customer Accounts (Transcribe from line 7)	776,762		
25	Customer Service and Informational (Transcribe from line 8)	213,957		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	3,423,877		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	27,126,521	1,674,879	28,801,400
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			

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			
47	Transmission			
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	27,126,521	1,674,879	28,801,400
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	16,158,954	997,706	17,156,660
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	16,158,954	997,706	17,156,660
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,949,904	182,137	3,132,041
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,949,904	182,137	3,132,041
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	152 - Fuel Stock Undistributed			
80	154 - Materials and Supplies			
81	163 - Stores Expense Undistributed	1,476,554	(1,476,554)	
82	165 - Other Prepayments			
83	182 - Other Regulatory Assets			
84	183 - Prelim Survey	6,739	(6,739)	
85	184 - Clearing Accounts	1,371,429	(1,371,429)	
86	185 - ODD Temporary Facilities	62,375		62,375
87	186 - Misc Deferred Debits	44,716		44,716
88	402 - Maintenance Exp			
89	407 - Regulatory Debits			
90	417 - Misc Exp			
91	418 - Nonoperating Rental Income			
92	421 - Misc Nonoperating Income			
93	426 - Political Activities	46,150		46,150
94	451 - Misc Service Rev - Nonaffil			
95	456 - Other Electric Revenue			
95	TOTAL Other Accounts	3,007,963	(2,854,722)	153,241
96	TOTAL SALARIES AND WAGES	49,243,342		49,243,342

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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.

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> A Resubmission		

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)	45,626,856	76,076,261	101,394,197	133,171,897
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(3,268,739)	(11,168,148)	(17,263,158)	(30,006,920)
4	Transmission Rights	(4,815,169)	(6,170,601)	(6,943,799)	(10,368,174)
5	Ancillary Services	(139,191)	(272,656)	(174,062)	799,970
6	Other Items (list separately)				
7	Congestion	2,507,511	3,718,736	3,861,481	5,930,548
8	Operating Reserves	3,316,805	3,750,396	4,032,296	4,552,121
9	Transmission Purchase Expense	639,328	1,075,036	1,097,057	1,122,167
10	Transmission Losses	1,149,729	1,709,842	3,142,150	3,392,535
11	Meter Corrections	158,245	842,773	1,781,865	1,882,599
12	Inadvertent	(17,681)	(39,801)	(43,258)	(66,374)
13	Capacity Credits	30,326	50,881	50,881	50,881
46	TOTAL	45,188,020	69,572,719	90,935,650	110,461,250

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		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	0					
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
FOOTNOTE DATA			

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

The final grandfathered contracts (under the AEP OATT) expired 12/31/2010. Currently, services are provided under the SPP and PJM OATTs.

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> 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: 0									
1	January	0								
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total				0	0	0	0	0	0

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 2026-04-09	Year/Period of Report End of: 2025/ Q4
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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)	5,277,604
3	Steam	3,181,793	23	Requirements Sales for Resale (See instruction 4, page 311.)	32,141
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	577,324
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
6.1	Solar		27	Total Energy Losses	428,650
6.2	Wind		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	6,315,719
7	Other				
8	Less Energy for Pumping				
9	Net Generation (Enter Total of lines 3 through 8)	3,181,793			
10	Purchases (other than for Energy Storage)	3,133,926			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	6,315,719			

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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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: 0					
29	January	697,660	28,028	1,347	22	9
30	February	538,667	18,875	1,156	22	8
31	March	496,612	23,886	999	3	8
32	April	445,073	26,127	878	9	8
33	May	426,143	27,866	784	15	18
34	June	556,598	94,127	935	25	14
35	July	580,985	47,036	930	31	16
36	August	527,133	63,904	917	19	17
37	September	417,297	33,857	765	5	17
38	October	467,001	56,141	705	24	9
39	November	567,641	133,004	908	29	9
40	December	594,909	48,666	1,171	15	8
41	Total	6,315,719	601,517			

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	(2) <input type="checkbox"/> A Resubmission		

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: 0	Plant Name: Big Sandy	Plant Name: Mitchell- Total	Plant Name: Mitchell-KEPCo Share
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		STEAM	STEAM	STEAM
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		CONVENTIONAL	OUTDOOR BOILER	OUTDOOR BOILER
3	Year Originally Constructed		1963	1971	1971
4	Year Last Unit was Installed		2016	1971	1971
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)		280.50	1,633.00	817.00
6	Net Peak Demand on Plant - MW (60 minutes)		295	1,559	785
7	Plant Hours Connected to Load		7,228	6,280	6,280
8	Net Continuous Plant Capability (Megawatts)		0		0
9	When Not Limited by Condenser Water		295	1,560	780
10	When Limited by Condenser Water		295	1,560	780
11	Average Number of Employees		23	166	83
12	Net Generation, Exclusive of Plant Use - kWh		1,206,427,000	3,950,730,000	1,975,365,000
13	Cost of Plant: Land and Land Rights		1,761,182	7,014,102.00	3,224,928
14	Structures and Improvements		24,978,533	233,910,668.00	81,751,123
15	Equipment Costs		164,390,177	2,120,969,020.00	983,400,902
16	Asset Retirement Costs		6,618,088	38,378,403.00	17,228,869
17	Total Cost (10-23)		197,747,980	2,400,272,193	1,085,605,822
18	Cost per KW of Installed Capacity (line 17/5) Including		704.9839	1,469.8544	1,328.7709
19	Production Expenses: Oper, Supv, & Engr		2,032,479	4,450,189	2,470,625
20	Fuel		47,094,196	187,419,724	93,364,150
21	Coolants and Water (Nuclear Plants Only)		0		0
22	Steam Expenses		3,065	10,675,998	5,337,896
23	Steam From Other Sources		0		0
24	Steam Transferred (Cr)		0		0
25	Electric Expenses		202	149,353	74,842
26	Misc Steam (or Nuclear) Power Expenses		2,090,505	6,165,979	2,967,165
27	Rents		879	3,757	1,439
28	Allowances		(155,885)	15,662	15,522
29	Maintenance Supervision and Engineering		287,859	1,399,238	704,193
30	Maintenance of Structures		769,702	1,846,142	923,178
31	Maintenance of Boiler (or reactor) Plant		1,595,760	20,932,507	10,243,686
32	Maintenance of Electric Plant		1,881,692	8,170,836	4,085,371
33	Maintenance of Misc Steam (or Nuclear) Plant		595,607	1,773,864	886,936
34	Total Production Expenses	0	56,196,061	243,003,249	121,075,003
35	Expenses per Net kWh		0.0466	0.0615	0.0613

35	Plant Name	Big Sandy	Mitchell- Total	Mitchell- Total	Mitchell-KEPCo Share	Mitchell-KEPCo Share
36	Fuel Kind	Gas	Coal	Oil	Coal	Oil
37	Fuel Unit	Mcf	t	Boe	t	Boe
38	Quantity (Units) of Fuel Burned	10,222,703	1,753,584	78,145	876,792	38,961
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,214,000	12,378	138,033	12,378	138,033
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.287	87.676	106.482	87.676	106.482
41	Average Cost of Fuel per Unit Burned	4.449	93.851	105.914	93.851	106.219
42	Average Cost of Fuel Burned per Million BTU	3.665	3.791	18.269	3.791	18.322
43	Average Cost of Fuel Burned per kWh Net Gen	0.038	0.042	0.000	0.042	0.000
44	Average BTU per kWh Net Generation	10,283	11,077	0.000	11,077	0.000
Page 402-403						

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Kind of Plant (Run-of-River or Storage)	
2	Plant Construction type (Conventional or Outdoor)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total installed cap (Gen name plate Rating in MW)	
6	Net Peak Demand on Plant-Megawatts (60 minutes)	
7	Plant Hours Connect to Load	
8	Net Plant Capability (in megawatts)	
9	(a) Under Most Favorable Oper Conditions	
10	(b) Under the Most Adverse Oper Conditions	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	Cost of Plant	
14	Land and Land Rights	
15	Structures and Improvements	
16	Reservoirs, Dams, and Waterways	
17	Equipment Costs	
18	Roads, Railroads, and Bridges	
19	Asset Retirement Costs	
20	Total Cost (10-23)	
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	Production Expenses	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Hydraulic Expenses	
26	Electric Expenses	
27	Misc Hydraulic Power Generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Hydraulic Plant	
34	Total Production Expenses (total 23 thru 33)	
35	Expenses per net kWh	

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original		
	(2)		
	<input type="checkbox"/> 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	0
15	Reservoirs, Dams, and Waterways	0
16	Water Wheels, Turbines, and Generators	0
17	Accessory Electric Equipment	0
18	Miscellaneous Powerplant Equipment	0
19	Roads, Railroads, and Bridges	0
20	Asset Retirement Costs	0
21	Total Cost (10-23)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	0
25	Water for Power	0
26	Pumped Storage Expenses	0
27	Electric Expenses	0
28	Misc Pumped Storage Power generation Expenses	0
29	Rents	0
30	Maintenance Supervision and Engineering	0
31	Maintenance of Structures	0
32	Maintenance of Reservoirs, Dams, and Waterways	0
33	Maintenance of Electric Plant	0
34	Maintenance of Misc Pumped Storage Plant	0
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

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		

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													
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5													
6													
7													
8													
9													
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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)			
42													
43													
44													
45													
46													

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	(2) <input type="checkbox"/> A Resubmission		

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)
35	TOTAL		0	0	0	0	0	0	0	0		0

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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	TOTAL		0	0	0	0	0	0
36	TOTAL		0	0	0	0	0	0

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	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 (a)	To (b)	Operating (c)	Designated (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)			Land (j)	Construction Costs (k)	Total Costs (l)
1	0700 BIG SANDY, KY	AMOS WV	765.00	765.00	3	0.13	0	1	954 MCMA			
2	0701 BIG SANDY, KY	SARGENTS, OH	765.00	765.00	3	24.20	0	1	954 MCMA			
3	0701 BIG SANDY, KY	SARGENTS, OH	765.00	765.00	3	4.79	0	1				
4	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	3	12.65	0	1	4-954 KCM ACSR			
5	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	3	3.04	0	1				
6	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	3	58.26	0	1				
7	0703 HANGING ROCK, OH	JEFFERSON, IN	765.00	765.00	3	154.74	0	1	1351.5 KCM ACSR			
8	0300 BIG SANDY, KY	TRI-STATE, WV	345.00	345.00	3	8.36	0	1	954 KCM ACSR			
9	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	1	0.33	0	1	500 KCM CU			
10	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	2	16.84	0	1	500 KCM CU			
11	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	3	0.06	0	1	795 KCM ACSR			
12	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	2	0.96	0	2	795 KCM ACSR			
13	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	3	0.35	0	2	795 KCM ACSR			
14	0135 WOOTEN	ARNOLD DELVINTA (LGE)	161.00	161.00	1	1.09	0	1	795 KCM ACSR			
15	0136 WOOTEN EXTENSION		161.00	161.00	1	0.04	0	1	795 KCM ACSR			
16	0143 HAZARD	WOOTON	161.00	161.00	1	0.60	0	1	795 KCM ACSR			
17	0143 HAZARD	WOOTON	161.00	161.00	1	0.98	0	2	795 KCM ACSR			
18	0143 HAZARD	WOOTON	161.00	161.00	3	0.26	0	2	795 KCM ACSR			
19	0143 HAZARD	WOOTON	161.00	161.00	3	1.16	0	1	795 KCM ACSR			
20	0143 HAZARD	WOOTON	161.00	161.00	2	3.58	0	1	795 KCM ACSR			
21	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	3	12.08	0	1	2-556.5 KCM ACSR			
22	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	3	14.77	0	2	795 KCM ACSR			
23	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	0	0.00	0	0	2-556.5 KCM ACSR			
24	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	3	0.32	0	1	1272 ACSS			
25	0101 BIG SANDY, KY	W HUNTINGTON, WV	138.00	138.00	3	0.33	0	1	1033.5 KCM ACSR			
26	0102 BELLEFONTE, KY	N PROCTORVILLE, OH	138.00	138.00	3	0.81	0	2	795 KCM ACSR			
27	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	3	5.91	0	1	397.5 MCMCU			
28	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	3	23.25	0	1				
29	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	3	2.30	0	1	636 MCMA			
30	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	1	16.09	17	1				
31	0107 LOGAN, WV	SPRIGG, KY	138.00	138.00	3	0.48	0	2	397 MCMA			
32	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	1.48	0	1	954KCM ACSR			

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)
33	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	3.31	0	1	795KCM ACSR			
34	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	3	30.88	0	1	636KCM ACSR			
35	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	22.86	0	1	636KCM ACSR			
36	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	1	0.01	0	1	636KCM ACSR			
37	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	3	0.71	14	1	795 MCMA			
38	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	1	0.38	0	1				
39	0113 CHADWICK	KY ELECTRIC STEEL	138.00	138.00	1	8.09	0	1	795 MCMA			
40	0115 CHADWICK	COALTON	138.00	138.00	1	0.98	0	1	795 MCMA			
41	0133 CHADWICK EXTENSION		138.00	138.00		1.06	0	1	795KCM ACSR			
42	0117 MILBROOK PARK, OH	FULLERTON	138.00	138.00	1	5.08	2	1	556.5 MCM			
43	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	1	25.83	0	1	795 MCMA			
44	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	3	0.63	0	0	1590 KCM			
45	0120 HATFIELD	SPRIGG	138.00	138.00	1	5.88	0	1	1033 MCM			
46	0121 HATFIELD	INEZ	138.00	138.00	1	14.67	0	1	1033.5 VAR			
47	0122 INEZ	LOVELY	138.00	138.00	1	6.86	0	1	1033.5 VAR			
48	0126 INEZ	MARTIKI	138.00	138.00	1	0.30	0	1	336.4 KCM ACSR			
49	0127 BIG SANDY	INEZ	138.00	138.00	3	25.08	0	1	795 MCMA			
50	0127 BIG SANDY	INEZ	138.00	138.00	3	0.28		2	795 KCM ACSR			
51	0106 DORTON	FLEMING	138.00	138.00	1	6.85	0	1	795 MCMA			
52	0106 DORTON	FLEMING	138.00	138.00	3	0.83	0	0	795 MCMA			
53	0108 BEAVER CREEK	SPRIGG #1	138.00	138.00	1	32.60	0	1	397 MCMA			
54	0124 BIG SANDY	SOUTH NEAL	138.00	138.00	1	0.01	0	1	1033.5 VAR			
55	0109 BEAVER CREEK	SPRIGG #3	138.00	138.00		0.00	0	0				
56	0125 BELLEFONTE	AK STEEL OXYGEN PLANT	138.00	138.00	3	0.22	0	2	795 ACSR			
57	0130 JOHNS CREEK	SPRIGG	138.00	138.00	3	13.00	0	0	1033 MCM			
58	0131 BAKER	BIG SANDY EXT.	138.00	138.00	3	1.00	0	1	1351 KCM			
59	0131 BAKER	BIG SANDY EXT.	138.00	138.00	1	0.05	0	2	2 - 1351KCM ACSR			
60	0128 INEZ	JOHNS CREEK	138.00	138.00	3	17.00	0	0	2-556.5 MCM			
61	0129 BEAVER CREEK	JOHNS CREEK	138.00	138.00	3	22.25	0	2	1033.5KCM ACSR			
62	0132 GRANGSTON LOOP		138.00	138.00	3	0.84	0	2	556.5 KCM ACSR			
63	0137 HAYS BRANCH	MORGAN FORK	138.00	138.00	3	8.30	0	1	795 ACSR			
64	0138 SOFT SHELL	BEAVER CREEK	138.00	138.00	3	1.40	0	2	1590 ACSR			

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 (a)	To (b)	Operating (c)	Designated (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)			Land (j)	Construction Costs (k)	Total Costs (l)
65	0138 SOFT SHELL	SPICEWOOD	138.00	138.00	3	1.40	0	2	1590 ACSR			
66	0139 MORGAN FORK	BETSY LANE	138.00	138.00	3	0.10	0	1	795 ACSR			
67	0139 MORGAN FORK	BEAVER CREEK	138.00	138.00	3	0.10	0	1	795 ACSR			
68	0140 BONNYMAN	SOFT SHELL	138.00	138.00	3	0.88	0	2	1590 KCM ACSS			
69	0140 BONNYMAN	SOFT SHELL	138.00	138.00	1	19.15	0	1	1590 KCM ACSS			
70	0154 Racoon Extension		138.00	138.00	1	0.20	0	2	1033.5KCM ACSR			
71	0119 BETSY LAYNE	ALLEN	46.00	138.00	1	5.89	0	1	795KCM ACSR			
72	0119 BETSY LAYNE	ALLEN	46.00	138.00	3	0.22	0	2	1033.5KCM ACSR			
73	0119 BETSY LAYNE	ALLEN	46.00	138.00	1	0.33	0	2	1033.5KCM ACSR			
74	0142 STANVILLE EXTENSION		138.00	138.00	1	0.42	0	1	1033.5KCM ACSR			
75	0117 FULLERTON	MILLBROOK	69.00	138.00	1	(0.05)	0	1	556 KCM ACSR			
76	0160 INEZ	MARTIN COUNTY SOLAR NO. 1	138.00	138.00	1	0.04	0	1	795 KCM ACSS			
77	0144 WOOTON	STINNETT	161.00	161.00	3	4.34	0	1	795 KCM ACSR			
78	0144 WOOTON	STINNETT	161.00	161.00	1	0.12	0	1	795 KCM ACSR			
79	0144 WOOTON	STINNETT	161.00	161.00	2	8.32	0	1	795 KCM ACSR			
80	0149 KEWANEE 138KV EXTENSION		138.00	138.00	1	0.21	0	2	1033 KCM ACSR			
81	0149 KEWANEE 138KV EXTENSION		138.00	138.00	3	4.86	0	2	1033 KCM ACSR			
82	0146 LESLIE 161KV EXTENSION		161.00	161.00	3	0.31	0	0	795 KCM ACSR			
83	0146 LESLIE 161KV EXTENSION		161.00	161.00	3	0.31	0	2	795 KCM ACSR			
84	0136 WOOTON 161KV EXTENSION		161.00	161.00	1	(0.12)	0	1	795 KCM ACSR			
85	LINES < 132KV		69.00	69.00		592.58	6.03	0				
86	Line cost and expense are	not available by individual								44,095,726	599,910,422	644,006,148
87	transmission line	Total shown in Column j - p										
36	TOTAL					1,267.09	39.03	98		44,095,726.00	599,910,422.00	644,006,148.00

Line No.	EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(m)	(n)	(o)	(p)
1				
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Line No.	EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(m)	(n)	(o)	(p)
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86	31,418	6,270,416		6,301,834
87				
36	31,418.00	6,270,416.00	0.00	6,301,834.00

Name of Respondent: Kentucky Power Company	This report is: (1)	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	<input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		

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 (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Construction (q)
	From (a)	To (b)			Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)	Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1	Nothing to report																	
44	TOTAL		0		0	0	0											

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	(2) <input type="checkbox"/> A Resubmission		

SUBSTATIONS

- Report below the information called for concerning substations of the respondent as of the end of the year.
- Substations which serve only one industrial or street railway customer should not be listed below.
- 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.
- 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).
- Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
- 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	ALLEN (KP) - KY	Transmission		46.00	12.00	0.00	6.25	1	0		0	0.00
2	ALLEN (KP) - KY	Transmission		46.00	0.00	0.00	0.00	0	0	STATCAP	1	13.20
3	ASHLAND - KY	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	16.20
4	ASHLAND - KY	Transmission		69.00	12.00	0.00	12.00	1	0		0	0.00
5	BARRENSHE - KY	Transmission		69.00	12.00	0.00	25.00	1	0		0	0.00
6	BEAVER CREEK - KY	Transmission		138.00	0.00	0.00	0.00	0	0	Air Core Reactor	3	0.00
7	BEAVER CREEK - KY	Transmission		138.00	69.00	46.00	90.00	1	0		0	0.00
8	BEAVER CREEK - KY	Distribution		138.00	0.00	0.00	0.00	0	0	Reactor	3	0.00
9	BEAVER CREEK - KY	Transmission		138.00	70.50	46.00	90.00	1	0		0	0.00
10	BEAVER CREEK - KY	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	2	124.80
11	BEAVER CREEK - KY	Distribution		138.00	34.50	0.00	30.00	1	0		0	0.00
12	BECKHAM - KY	Distribution		138.00	34.50	0.00	30.00	1	0		0	0.00
13	BECKHAM - KY	Distribution		138.00	0.00	0.00	0.00	0	0	STATCAP	1	43.20
14	BEEFHIDE - KY	Distribution		138.00	34.00	0.00	12.00	1	0		0	0.00
15	BELFRY - KY	Transmission		46.00	12.00	0.00	10.50	1	0		0	0.00
16	BELHAVEN - KY	Transmission		138.00	13.09	0.00	12.00	1	0		0	0.00
17	BELLEFONTE - KY	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	14.40
18	BELLEFONTE - KY	Distribution		138.00	13.09	0.00	12.00	1	0		0	0.00
19	BIG SANDY 138KV - KY	Distribution		138.00	34.50	0.00	20.00	1	0		0	0.00
20	BIG SANDY 138KV - KY	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
21	BIG SANDY 138KV - KY	Distribution		138.00	0.00	0.00	0.00	0	0	Air Core Reactor	3	0.00
22	BIG SANDY 138KV - KY	Distribution		138.00	69.50	13.20	128.80	1	0		0	0.00
23	BLUE GRASS - KY	Distribution		69.00	12.00	0.00	10.50	1	0		0	0.00
24	BONNYMAN - KY	Distribution		69.00	34.50	0.00	30.00	1	0		0	0.00
25	BONNYMAN - KY	Distribution		138.00	70.50	13.00	130.00	1	0		0	0.00
26	BULAN - KY	Distribution		69.00	12.00	0.00	9.38	1	0		0	0.00
27	BURDINE - KY	Distribution		46.00	12.00	0.00	7.50	1	0		0	0.00
28	BUSSEYVILLE - KY	Distribution		138.00	34.50	0.00	55.00	2	0		0	0.00
29	CANNONSBURG - KY	Transmission		69.00	36.20	0.00	18.00	1	0		0	0.00
30	CEDAR CREEK - KY	Transmission		138.00	69.50	46.00	54.00	1	0		0	0.00
31	CEDAR CREEK - KY	Transmission		138.00	36.20	0.00	15.00	0	1		0	0.00
32	CHADWICK - KY	Transmission		138.00	69.00	34.50	200.00	1	0		0	0.00
33	CHAVIES - KY	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	9.60
34	CHAVIES - KY	Distribution		69.00	13.09	0.00	3.75	1	0		0	0.00
35	COALTON - KY	Distribution		69.00	12.00	0.00	25.00	1	0		0	0.00
36	COALTON - KY	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	14.40
37	COLEMAN - KY	Distribution		69.00	34.50	0.00	20.00	1	0		0	0.00

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)
38	COLEMAN - KY	Distribution		69.00	12.00	0.00	3.75	1	0		0	0.00
39	COLLIER - KY	Distribution		69.00	34.00	0.00	25.00	1	0		0	0.00
40	COLLIER - KY	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	9.60
41	COMBS - KY	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	13.20
42	COMBS - KY	Transmission		69.00	13.09	0.00	7.50	1	0		0	0.00
43	DAISY - KY	Distribution		69.00	12.00	0.00	4.70	1	0		0	0.00
44	DAISY - KY	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	13.20
45	DEWEY - KY	Distribution		138.00	34.50	0.00	25.00	1	0		0	0.00
46	DEWEY - KY	Distribution		138.00	69.00	12.00	90.00	1	0		0	0.00
47	DORTON - KY	Distribution		138.00	70.50	46.00	144.00	2	0		0	0.00
48	DRAFFIN - KY	Transmission		46.00	12.00	0.00	10.50	1	0		0	0.00
49	EAST PRESTONSBURG - KY	Distribution		46.00	12.00	0.00	20.00	1	0		0	0.00
50	ELWOOD (KP) - KY	Transmission		46.00	0.00	0.00	0.00	0	0	STATCAP	1	14.40
51	ELWOOD (KP) - KY	Transmission		46.00	34.50	6.50	25.00	1	0		0	0.00
52	ENGLE - KY	Transmission		69.00	34.50	0.00	20.00	1	0		0	0.00
53	FALCON - KY	Transmission		69.00	46.00	0.00	20.00	1	0		0	0.00
54	FEDS CREEK - KY	Transmission		69.00	12.00	0.00	22.34	1	0		0	0.00
55	FISHTRAP - KY	Transmission		69.00	12.00	0.00	3.75	1	0		0	0.00
56	FORTY SEVENTH STREET - KY	Transmission		69.00	13.09	0.00	12.00	1	0		0	0.00
57	GARRETT (KP) - KY	Transmission		46.00	12.00	0.00	10.50	1	0		0	0.00
58	GRAHN - KY	Transmission		69.00	12.00	0.00	3.13	1	0		0	0.00
59	GRAYS BRANCH - KY	Distribution		69.00	12.00	0.00	5.00	1	0		0	0.00
60	GRAYSON - KY	Distribution		69.00	12.00	0.00	20.00	1	0		0	0.00
61	HADDIX - KY	Distribution		69.00	36.20	0.00	15.00	1	0		0	0.00
62	HADDIX - KY	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	5.40
63	HATFIELD (KP) - KY	Distribution		138.00	69.00	46.00	130.00	1	0		0	0.00
64	HAYWARD - KY	Distribution		69.00	13.09	0.00	9.38	1	0		0	0.00
65	HAZARD - KY	Distribution		138.00	70.50	13.09	78.00	1	0		0	0.00
66	HAZARD - KY	Distribution		138.00	0.00	0.00	0.00	0	0	STATCAP	1	46.10
67	HAZARD - KY	Distribution		161.00	138.00	13.09	210.00	0	1		0	0.00
68	HAZARD - KY	Transmission		34.50	12.00	0.00	9.38	1	0		0	0.00
69	HAZARD - KY	Transmission		138.00	36.20	0.00	18.00	1	0		0	0.00
70	HAZARD - KY	Distribution		138.00	0.00	0.00	0.00	0	0	XSLR - 0.6mH / 480A	3	0.11
71	HAZARD - KY	Distribution		161.00	138.00	13.09	3684.00	18	0		0	0.00
72	HAZARD - KY	Distribution		161.00	70.50	13.09	1842.00	9	0		0	0.00
73	HENRY CLAY - KY	Distribution		46.00	0.00	0.00	0.00	0	0	STATCAP	1	9.60
74	HENRY CLAY - KY	Transmission		46.00	34.50	0.00	30.00	1	0		0	0.00
75	HIGHLAND (KP) - KY	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	0.00
76	HIGHLAND (KP) - KY	Transmission		69.00	13.09	0.00	25.00	1	0		0	0.00
77	HITCHINS - KY	Distribution		69.00	13.09	0.00	25.00	1	0		0	0.00
78	HOODS CREEK - KY	Distribution		69.00	13.09	0.00	7.50	1	0		0	0.00
79	HOWARD COLLINS - KY	Distribution		69.00	13.09	0.00	12.00	1	0		0	0.00
80	HOWARD COLLINS - KY	Distribution		69.00	12.00	0.00	10.50	1	0		0	0.00
81	INDEX - KY	Distribution		69.00	12.00	0.00	9.40	1	0		0	0.00
82	INEZ - KY	Transmission		138.00	70.50	13.09	54.00	1	0		0	0.00
83	INEZ - KY	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	2	105.60
84	JACKSON - KY	Transmission		69.00	12.00	0.00	7.00	1	0		0	0.00
85	JACKSON - KY	Transmission		69.00	13.09	0.00	7.50	1	0		0	0.00
86	JACKSON - KY	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	9.60

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)
87	JEFF - KY	Distribution		69.00	36.20	0.00	30.00	1	0		0	0.00
88	JENKINS - KY	Distribution		69.00	12.00	0.00	10.50	1	0		0	0.00
89	JOHNS CREEK - KY	Distribution		138.00	70.50	36.20	432.00	8	0		0	0.00
90	JOHNS CREEK - KY	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	9.60
91	JOHNS CREEK - KY	Distribution		138.00	0.00	0.00	0.00	0	0	STATCAP	1	52.80
92	KENWOOD - KY	Distribution		46.00	12.00	0.00	20.00	1	0		0	0.00
93	KENWOOD - KY	Distribution		46.00	0.00	0.00	0.00	0	0	STATCAP	1	7.20
94	KEWANEE - KY	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	1	34.60
95	KEWANEE - KY	Distribution		138.00	0.00	0.00	0.00	0	0	XSLR - 0.6mH / 480A	3	0.00
96	KIMPER - KY	Distribution		69.00	12.00	0.00	9.38	1	0		0	0.00
97	LESLIE - KY	Distribution		161.00	70.50	40.73	520.00	4	0		0	0.00
98	LESLIE - KY	Distribution		69.00	0.00	0.00	0.00	0	0	1200A Air-Core Reactor	3	0.00
99	LESLIE - KY	Distribution		161.00	70.50	13.09	520.00	4	0		0	0.00
100	LESLIE - KY	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	14.40
101	LESLIE - KY	Distribution		69.00	34.50	0.00	30.00	1	0		0	0.00
102	LOVELY - KY	Distribution		138.00	36.20	0.00	18.00	1	0		0	0.00
103	MANSBACH - KY	Distribution		69.00	4.00	0.00	9.38	1	0		0	0.00
104	MAYKING - KY	Distribution		69.00	12.00	0.00	20.00	1	0		0	0.00
105	MAYO TRAIL - KY	Distribution		69.00	13.09	0.00	25.00	1	0		0	0.00
106	MCKINNEY - KY	Distribution		34.50	12.00	0.00	6.67	1	0		0	0.00
107	MCKINNEY - KY	Distribution		46.00	34.00	0.00	20.00	1	0		0	0.00
108	MORGAN FORK - KY	Distribution		138.00	0.00	0.00	0.00	0	0	STATCAP	1	43.20
109	NEW CAMP - KY	Distribution		69.00	13.09	0.00	40.00	2	0		0	0.00
110	OLIVE HILL - KY	Distribution		69.00	4.00	0.00	5.00	1	0		0	0.00
111	OLIVE HILL - KY	Distribution		69.00	12.00	0.00	7.50	1	0		0	0.00
112	PRESTONSBURG - KY	Distribution		46.00	0.00	0.00	0.00	0	0	STATCAP	1	9,600.00
113	PRESTONSBURG - KY	Distribution		46.00	13.09	0.00	10.00	1	0		0	0.00
114	PRINCESS - KY	Distribution		69.00	34.50	0.00	20.00	1	0		0	0.00
115	PRINCESS - KY	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	21.60
116	RACELAND - KY	Distribution		69.00	2.40	0.00	7.50	1	0		0	0.00
117	REEDY COAL - KY	Distribution		69.00	34.00	0.00	20.00	1	0		0	0.00
118	RUSSELL - KY	Distribution		69.00	12.00	0.00	12.00	1	0		0	0.00
119	RUSSELL FORK - KY	Transmission		69.00	12.00	0.00	3.75	1	0		0	0.00
120	SALISBURY (KP) - KY	Distribution		46.00	13.09	0.00	20.00	1	0		0	0.00
121	SECOND FORK - KY	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	14.40
122	SECOND FORK - KY	Transmission		69.00	13.09	0.00	8.40	1	0		0	0.00
123	SHAMROCK - KY	Transmission		69.00	34.50	0.00	10.50	1	0		0	0.00
124	SIDNEY - KY	Transmission		69.00	13.09	0.00	12.00	1	0		0	0.00
125	SLEMP - KY	Distribution		69.00	34.00	0.00	20.00	1	0		0	0.00
126	SLEMP - KY	Distribution		69.00	36.20	0.00	7.50	1	0		0	0.00
127	SOFT SHELL - KY	Distribution		138.00	34.50	0.00	30.00	1	0		0	0.00
128	SOUTH PIKEVILLE - KY	Distribution		69.00	13.09	0.00	25.00	1	0		0	0.00
129	SOUTH SHORE - KY	Distribution		69.00	13.09	0.00	7.50	1	0		0	0.00
130	STINNETT - KY	Distribution		161.00	34.00	7.20	14.93	1	0		0	0.00
131	STINNETT - KY	Distribution		161.00	34.50	7.20	22.40	0	1		0	0.00
132	STINNETT - KY	Distribution		161.00	34.50	7.20	22.40	1	0		0	0.00
133	STONE - KY	Distribution		138.00	70.50	46.00	90.00	1	0		0	0.00
134	TENTH STREET - KY	Distribution		69.00	13.09	0.00	25.00	1	0		0	0.00

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)
135	THELMA - KY	Distribution		46.00	0.00	0.00	0.00	0	0	STATCAP	1	7.20
136	THELMA - KY	Distribution		138.00	0.00	0.00	0.00	0	0	STATCAP	1	32.40
137	THELMA - KY	Distribution		138.00	69.00	12.00	90.00	1	0		0	0.00
138	THELMA - KY	Distribution		138.00	69.00	46.00	70.00	1	0		0	0.00
139	TOM WATKINS - KY	Distribution		69.00	12.00	0.00	10.50	1	0		0	0.00
140	TOPMOST - KY	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
141	TYGART - KY	Distribution		69.00	13.09	0.00	54.00	4	0		0	0.00
142	VICCO - KY	Distribution		138.00	34.50	0.00	18.00	1	0		0	0.00
143	WEEKSBURY - KY	Transmission		69.00	13.09	0.00	5.00	1	0		0	0.00
144	WEST PAINTSVILLE - KY	Distribution		69.00	12.00	0.00	25.00	1	0		0	0.00
145	WHITESBURG - KY	Distribution		69.00	12.00	0.00	25.00	1	0		0	0.00
146	WHITESBURG - KY	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	13.20
147	WHITESBURG - KY	Transmission		69.00	13.09	0.00	7.50	1	0		0	0.00
148	WORTHINGTON - KY	Transmission		69.00	12.00	0.00	1.50	1	0		0	0.00
150	TotalTransmissionSubstationMember											10,313
151	Total											10,313

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Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
	(2) <input type="checkbox"/> 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	Administrative and General Expenses - Maintenance	AEPSC	935	610,689
3	Administrative and General Expenses - Maintenance	APCo	935	301,553
4	Administrative and General Expenses - Operation	AEPSC	920-926,928,930,931	718,358
5	AEP Transmission	AEPSC	920,923	337,307
6	Central Machine Shop	APCo	107,506,,512,513,920	342,090
7	Chief Executive Officer	AEPSC	920,923	3,273,288
8	Chief Financial Officer	AEPSC	920,923	3,510,328
9	Chief Info & Tech Officer	AEPSC	920,923	1,256,212
10	Civil & Political Activities and Other Svcs	AEPSC	426	442,505
11	Construction Services	AEPSC	107,108	31,885,558
12	Construction Services	APCo	107,108	340,982
13	Customer Accounts Expenses	AEPSC	901-903,905	3,633,383
14	Distribution Expenses - Maintenance	AEPSC	590-594,597,598	695,488
15	Distribution Expenses - Operation	AEPSC	580,582-584,586-588	1,323,999
16	Factored Customer A/R Bad Debts	AEP Credit	426	1,261,563
17	Factored Customer A/R Expense	AEP Credit	426	3,397,858
18	Fuel & Storeroom Services	AEPSC	152,163	1,387,534
19	Materials and Supplies	AEP Texas	107,935	277,435
20	Materials and Supplies	APCo	107,154,184,512-513,571,588,592,935	1,082,195
21	Materials and Supplies	OPCo	107,570,571,592	3,529,887
22	O&M Services for Jointly Owned Facility - Mitchell	WPCo	107,108,154,186,408,417,421,426,500-502,505-507,510-514,557,920-926,928,930,931,935	52,268,848
23	Other Power Supply Expenses	AEPSC	556,557	283,099
24	Research and Other Services	AEPSC	183,186,188	445,124
25	Steam Power Generation - Maintenance	AEPSC	510-514	444,239
26	Steam Power Generation - Operation	AEPSC	500-502,506	1,678,477
27	Transmission Expenses - Maintenance	AEPSC	568-573	1,754,397
28	Transmission Expenses - Operation	AEPSC	560,561,562,563,566	4,567,338
19				
20	Non-power Goods or Services Provided for Affiliated			
21	Building and Property Leases	AEPSC	454	726,738
22	Fleet and Vehicle Charges	AEPSC	See Footnote	1,459,572
23	Materials and Supplies	APCo	154	488,980
24	Use of Jointly Owned Facility	KYTCo	454	662,723
42				

Name of Respondent: Kentucky Power Company	This report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report: 04/09/2026	Year/Period of Report End of: 2025/ Q4
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FOOTNOTE DATA

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

Cost related to AEP's fleet vehicles are allocated in the same manner as the labor of each department utilizing the vehicles. To the extent a department provides service to another affiliate company, an applicable share of their fleet costs are also assigned to that affiliate company.

