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

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

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

IV. When to Submit

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

"Sec. 304.

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

"Sec. 309.

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

GENERAL PENALTIES

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

FERC FORM NO. 1 REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER		
IDENTIFICATION		
01 Exact Legal Name of Respondent Kentucky Power Company		02 Year/ Period of Report End of: 2024/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 1 Riverside Plaza, Columbus, OH 43215-2373		
05 Name of Contact Person Jason M. Johnson		06 Title of Contact Person Accountant
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) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/08/2025
Annual Corporate Officer Certification		
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.		
01 Name Jeffrey W Hoersdig 02 Title Assistant Controller	03 Signature Jeffrey W Hoersdig	04 Date Signed (Mo, Da, Yr) 04/08/2025
Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.		

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
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	
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: ☐ Two copies will be submitted ☐ No annual report to stockholders is prepared		
Page 2			

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

GENERAL INFORMATION

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

Jeffrey W. Hoersdig, Assistant Controller

1 Riverside Plaza Columbus, OH 43215-2373

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.

Kentucky - July 21,1919

State of Incorporation:

Date of Incorporation:

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.

Electric - Kentucky

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

(2)
☑ No

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

CONTROL OVER RESPONDENT

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

American Electric Power Company, Inc. - Ownership of 100% of Respondent's Common Stock

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

Definitions

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	[(a)] Footnote				

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: OfficerTitle

Schedule Page: 104 Line No.: 1 Column: a

The following table provides summary information concerning compensation earned by our Chief Executive Officer, our former Chief Financial Officer; the three other most highly compensated executive officers; our former Interim President and Chief Executive Officer; and our former Chair of the Board, President, and Chief Executive Officer.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 ($)
William J. Fehrman								
President and Chief Executive Officer	2024	$ 628,846	$ 2,000,000	$ 9,469,144	$ 1,100,000	$ —	$ 59,032	$ 13,257,022
Charles E. Zebula								
Executive Vice President and Chief Financial Officer	2024	$ 724,327	$ —	$ 2,250,000	$ 605,840	$ 177,002	$ 85,564	$ 3,842,733
Greg B. Hall								
Executive Vice President and Chief Commercial Officer	2024	$ 575,491	$ —	$ 2,600,000	$ 485,416	$ 167,640	$ 70,977	$ 3,899,524
David M. Feinberg								
Executive Vice President, General Counsel and Secretary	2024	$ 771,628	$ —	$ 1,827,648	$ 447,448	$ 132,958	$ 77,057	$ 3,256,739
Therace M. Risch								
Executive Vice President, Chief Information and Technology Officer	2024	$ 684,906	$ —	$ 1,607,665	$ 536,999	$ 61,118	$ 35,400	$ 2,926,088
Ben Fowke								
Former Interim President and Chief Executive Officer	2024	$ 1,058,462	$ —	$ 8,060,780	$ 2,000,000	$ —	$ 210,777	$ 11,330,019
Julia A. Sloat								
Former Chair of the Board, President and Chief Executive Officer	2024	$ 327,692	$ —	$ —	$ —	$140,257	$ 2,454,334	$ 2,922,283

1.Amounts in the salary column are composed of executive salaries earned for the year shown, which include 262 days of pay for 2024, due to 2 additional workdays in 2024..

21.The amount in the bonus column for Mr. Fehrman reflects a negotiated hire bonus to be paid in 2024 following his hire as President and Chief Executive Officer on August 1.
3.The amounts reported in this column reflect the aggregate grant date fair value calculated in accordance with FASB ASC Topic 718 of the performance shares, restricted stock units (RSUs) and unrestricted shares 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, 2024 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 3-year performance period. The potential payout can range from 0 percent to 200 percent of the target number of performance shares, plus any dividend equivalents. The value of the performance shares will be based on three measures: a Board approved cumulative operating earnings per share measure (Cumulative EPS 50%), a total shareholder return relative to peer companies (Relative TSR 40%) and a measure of generation capacity additions that maintain reliability through the clean energy transition (Maintaining Reliability 10%). 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 2024 performance shares that are based on Cumulative EPS measured on the grant date is $3,500,000 for Mr. Fehrman, 825,000 for Mr. Hall, 1,237,500 for Mr. Feinberg, and $750,000 for Ms. Risch. The maximum amount payable for the 2024 performance shares that are based on Maintaining Reliability is $700,000 for Mr. Fehrman, $165,000 for Mr. Hall, $247,500 for Mr. Feinberg, and $150,000 for Ms. Risch. The grant date fair value of the 2024 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. Because the performance shares that are based on Relative TSR are subject to market conditions as defined under FASB ASC Topic 718, they did not have a maximum value on the grant date that differed from the grant date fair values presented in the table. Instead, the maximum value is factored into the calculation of the grant date fair value. The values realized from the 2022-2024 performance shares are included in the Option Exercises and Stock Vested for 2024 table.

4.The amounts shown in this column reflect annual incentive compensation paid for the year shown.

5.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 non-qualified 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 2024 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, 2024 for a discussion of the relevant assumptions. None of the named executive officers received preferential or above-market earnings on deferred compensation.

6.Amounts shown in the All Other Compensation column for 2024 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) relocation, (d) perquisites, (e) vacation payout (f) severance benefits, and (g) director fees. Ms. Sloat's severance benefits, including amounts already paid, are subject to her compliance with the terms of a Severance, Release of All Claims and Noncompetition Agreement, which includes an agreement not to compete with the Company for two years. The value of each item included in 2024 All Other Compensation column is listed in the following table:

Type	William J. Fehrman (7)	Charles E. Zebula	Greg B. Hall	David M. Feinberg	Therace M. Risch	Ben Fowke (7)	Julia A. Sloat
Retirement Savings Plan Match	$ 15,006	$ 15,525	$ 15,525	$ 15,525	$ 15,525	$ 15,525	$ 15,525
Supplemental Retirement Savings Plan Match	$ 10,956	$ 27,620	$ 19,607	$ 30,766	$ —	$ 24,092	$ 35,697
Relocation	$ 21,559	$ —	$ —	$ —	$ —	$ —	$ —
Perquisites	$ 555	$ 14,799	$ 16,238	$ —	$ 19,875	$ 20,632	$ 21,223
Vacation Payout	$ —	$ —	$ —	$—	$ —	$ 69,231	$ 19,038
Severance	$ —	$ —	$ —	$ —	$ —	$ —	$ 2,326,154
Director Fees	$ —	$ —	$ —	$ —	$ —	$ 57,205	$ —
Total	**$ 48,076**	**$ 57,944**	**$ 51,370**	**$ 46,291**	**$ 35,400**	**$ 186,685**	**$ 2,417,637**

7.Mr. Fehrman and Mr. Fowke were not employed by the Company prior to August 1 and February 26, 2024, respectively. Mr. Fowke was an outside director both prior to and after his service to the Company as Interim President and CEO.

Perquisites provided in 2024 included: financial counseling and tax preparation services and, for Board members (Mr. Fehrman, Mr. Fowke and Ms. Sloat) an allocated share of a group premium for directors' travel accident insurance. 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. From time to time, executive officers may receive customary gifts from third parties that sponsor events (subject to our policies on conflicts of interest).

Provided Ms. Sloat complies with the terms of a Severance, Noncompetition and Release of All Claims Agreement, she will be entitled to $5,760,000 in cash severance benefits and up to $15,650 in outplacement services in connection with her 2024 separation from AEP employment, $2,326,154 of which was paid to her in 2024.

Mr. Fehrman and, prior to their separations from AEP service, Mr. Fowke and Ms. Sloat were parties to Aircraft Time Sharing Agreements with the Company that allowed them to use our corporate aircraft for personal use. Neither Mr. Fowke nor Ms. Sloat used aircraft under these agreements in 2024. As required under these Aircraft Time Sharing Agreements, Mr. Fehrman reimbursed the Company for the full incremental cost of his personal use under his Aircraft Time Sharing Agreement (but not the fixed cost) calculated in accordance with federal aviation regulations associated with reimbursement for flight expenses to non-commercial aircraft operators. Accordingly, no value is shown for these amounts in the Summary Compensation Table. If the aircraft flew empty to pick up or 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. Mr. Fehrman's spouse also accompanied him on the corporate aircraft being used for business travel, but there was no incremental cost to AEP for those trips.

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	William J. Fehrman, Chair of the Board and Chief Executive Officer	Columbus, Ohio	false	false
2	Julia A. Sloat, Chair of the Board and Chief Executive Officer	Columbus, Ohio	false	false
3	Antonio P. Smyth, Vice President	Columbus, Ohio	false	false
4	David M. Feinberg, Vice President and Secretary	Columbus, Ohio	false	false
5	Cynthia G. Wiseman, President and Chief Operating Officer	Ashland,KY	false	false
6	Therace M. Risch, Vice President	Columbus, Ohio	false	false
7	Peggy I.Simmons,Vice President	Columbus, Ohio	false	false
8	Benjamin G S. Fowke - Chair of the Board, Chief Executive Officer and Senior Advisor	Columbus, Ohio	false	false
9	Phillip R. Ulrich, Vice President	Columbus, Ohio	false	false
10	Charles E Zebula, Vice President and Chief Financial Officer	Columbus, Ohio	false	false
11	Christian T. Beam , Vice President	Columbus, Ohio	false	false

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ Yes ☐ No

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

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	PJM Interconnection LLC - Attachment H-14	ER17-405

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

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

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	20241031-5410	10/31/2024	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
2	20240528-5349	05/28/2024	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

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

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1	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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

Date Acquired or Extended	Community	Period of Franchise & Termination	Consideration
3/21/2024	City of Greenup	Ten (10) years expiring 2034	None
4/11/2024	City of Coal Run	Twenty (20) years expiring April 11,2044	None
6/10/2024	City of Worthington	Twenty (20) years expiring June 10,2044	None
11/27/2024	City of Russell	Ten (10) years expiring November 27,2034	None

None

None

None

None

None

8. 79 Kentucky Power, KY employees represented by IBEW #978 were provided with a 2.5%
Wages increase effective May 1, 2024

Please refer to the Notes to Financial Statements pages 122-123

None

12. Not Used

13. Benjamin G S Fowke III, elected as Director, Chief Executive Officer and Chair of the Board effective on 02-26-2024. Daniel E Mueller, elected as Vice President-Tax effective on 01-27-2024. David P. Hoffman, elected as Vice President - General Assets effective on 01-20-2024. Noah K Hollis, elected as Assistant Treasurer effective on 03-30-2024. William J. Fehrman, elected as Chair of the Board, Chief Executive Officer and Director effective on 08/1/2024 Benjamin Fowke III, elected as Senior Advisor effective on 08/1/2024 and also resigned as Chair of the Board, Chief Executive Officer effective on 07/31/2024 and also as Director on 08/26/2024. Michele Ross, elected as Vice President - Distribution Region Operations effective on 08/03/2024. Jeffrey D. Newcomb, elected as Vice President - Regulatory & Finance effective on 08/19/2024. Matthew D Fransen, elected as Vice President and Treasurer effective on 12/01/2024. Julia A Sloat, resigned as Director, Chair of the Board, Chief Executive Officer effective on 02-25-2024. Daniel E Mueller, resigned as Assistant Vice President - Tax on 01-26-2024. James X Llende, resigned as Vice President-Tax on 01-25-2024. Renee V Hawkins, resigned as Assistant Treasurer effective on 05/03/2024. Everett G. Phillips, resigned as Vice President - Distribution Region Operations effective on 07/01/2024. Brian K. West, resigned as Vice President - Regulatory & Finance effective on 07/01/2024. Therace M. Risch, resigned as Director effective on 09/23/2024. Peggy I. Simmons, resigned as Director effective on 09/23/2024. Christian T. Beam, resigned as Director effective on 09/23/2024. Phillip R. Ulrich, resigned as Director effective on 09/23/2024. Antonio P. Smyth, resigned as Director effective on 09/23/2024. David P. Hoffman, resigned as Vice President - Generation Assets effective on 07/01/2024. Benjamin Fowke III resigned as Senior Advisor effective on 10/22/2024. Peggy I Simmons resigned as Vice President effective on 10/31/2024. Julie A Sherwood resigned as Vice President and Treasurer effective on 11/30/2024.
Proprietary capital ratio exceeds 30%

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	3,614,362,254	3,374,320,715
3	Construction Work in Process (107)	200	117,585,328	161,152,909
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,731,947,582	3,535,473,624
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	1,368,455,314	1,298,879,280
6	Net Utility Plant (Enter Total of line 4 less 5)		2,363,492,268	2,236,594,344
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)		2,363,492,268	2,236,594,344
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		502,366	571,711
19	(Less) Accum. Prov. for Depr. and Amort. (122)		179,574	242,250
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228	8,349,737	8,364,873
24	Other Investments (124)		692,884	707,401
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)		38,324,925	24,743,315
30	Long-Term Portion of Derivative Assets (175)		436,823	14,732
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		48,127,161	34,159,782
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		839,453	1,321,222
36	Special Deposits (132-134)		4,196,423	2,982,246
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		15,412,437	15,795,734
41	Other Accounts Receivable (143)		163,583	116,114
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		605	306
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		18,072,922	23,552,171
45	Fuel Stock (151)	227	57,068,481	78,362,191
46	Fuel Stock Expenses Undistributed (152)	227	2,421,988	2,275,502
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	23,973,785	25,255,256
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 (158.1 and 158.2)	228	8,515,890	8,554,258
53	(Less) Noncurrent Portion of Allowances	228	8,349,737	8,364,873
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)		2,241,790	2,026,633
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		2,956,857	2,653,918
61	Accrued Utility Revenues (173)		9,718,574	
62	Miscellaneous Current and Accrued Assets (174)			12,000,000
63	Derivative Instrument Assets (175)		5,691,344	3,078,245
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		436,823	14,732
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)		142,486,362	169,593,579
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		3,934,245	4,533,899
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	731,531,918	682,390,958
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,006,386	893,160
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	31,116,869	40,423,010
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		266,402	300,053
82	Accumulated Deferred Income Taxes (190)	234	82,133,216	74,967,031
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		849,989,036	803,508,111
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,404,094,828	3,243,855,816

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250	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	526,069,518	526,771,324
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	414,395,958	377,534,237
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)		990,915,476	954,755,561
17	**LONG-TERM DEBT**			
18	Bonds (221)	256		
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		25,000,000
21	Other Long-Term Debt (224)	256	1,215,000,000	1,280,000,000
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		592,937	660,062
24	Total Long-Term Debt (lines 18 through 23)		1,214,407,063	1,304,339,938
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		2,572,811	1,640,229
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		1,348,092	1,260,035
29	Accumulated Provision for Pensions and Benefits (228.3)		6,592,802	6,694,451
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		1,497,209	744,188
32	Long-Term Portion of Derivative Instrument Liabilities		6,782	973,993
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		88,832,997	18,276,486
35	Total Other Noncurrent Liabilities (lines 26 through 34)		100,850,693	29,589,382
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		60,683,964	36,823,006
39	Notes Payable to Associated Companies (233)		183,212,284	49,567,376
40	Accounts Payable to Associated Companies (234)		49,420,756	46,087,714
41	Customer Deposits (235)		38,265,250	38,026,871
42	Taxes Accrued (236)	262	43,482,953.00	48,910,684.00
43	Interest Accrued (237)		10,447,249	12,779,510
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		2,568,209	2,243,842
48	Miscellaneous Current and Accrued Liabilities (242)		11,198,591	24,438,811
49	Obligations Under Capital Leases-Current (243)		350,482	307,148

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)		460,774	8,899,914
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		6,782	973,993
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)		400,083,730	267,110,883
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		99,104	94,091
57	Accumulated Deferred Investment Tax Credits (255)	266		
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	11,422,215	10,621,717
60	Other Regulatory Liabilities (254)	278	120,166,057	128,533,845
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	23,637,880	25,206,884
63	Accum. Deferred Income Taxes-Other Property (282)		287,551,685	284,235,237
64	Accum. Deferred Income Taxes-Other (283)		254,960,926	239,368,279
65	Total Deferred Credits (lines 56 through 64)		697,837,867	688,060,053
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,404,094,828	3,243,855,817

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	706,582,368	622,721,863			706,582,368	622,721,863				
3	Operating Expenses											
4	Operation Expenses (401)	320	391,169,548	330,952,883			391,169,548	330,952,883				
5	Maintenance Expenses (402)	320	63,670,846	64,173,336			63,670,846	64,173,336				
6	Depreciation Expense (403)	336	102,688,187	105,866,188			102,688,187	105,866,188				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	1,209,506	375,756			1,209,506	375,756				
8	Amort. & Depl. of Utility Plant (404-405)	336	9,598,216	9,961,212			9,598,216	9,961,212				
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)		371,740	7,655,198			371,740	7,655,198				
13	(Less) Regulatory Credits (407.4)		(2,632,082)				(2,632,082)					
14	Taxes Other Than Income Taxes (408.1)	262	26,363,705	27,499,617			26,363,705	27,499,617				
15	Income Taxes - Federal (409.1)	262	3,175,965	(1,838,299)			3,175,965	(1,838,299)				
16	Income Taxes - Other (409.1)	262	338,204	828,944			338,204	828,944				

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
17	Provision for Deferred Income Taxes (410.1)	234, 272	69,566,828	60,148,120			69,566,828	60,148,120				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	68,703,396	87,190,214			68,703,396	87,190,214				
19	Investment Tax Credit Adj. - Net (411.4)	266										
20	(Less) Gains from Disp. of Utility Plant (411.6)		14,518	12,768			14,518	12,768				
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)		180,729	16			180,729	16				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		1,425,167	851,367			1,425,167	851,367				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		603,349,967	519,309,940			603,349,967	519,309,940				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		103,232,401	103,411,923			103,232,401	103,411,923				
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty 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)		330,190	321,610								
34	(Less) Expenses of Nonutility Operations (417.1)		645	180								
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)		1,002,524	201,571								
38	Allowance for Other Funds Used During Construction (419.1)		2,033,764	967,911								
39	Miscellaneous Nonoperating Income (421)		(8,446)	25,006								
40	Gain on Disposition of Property (421.1)											
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		3,351,742	1,510,273								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		174	1,428								

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		1,649,345	971,881								
46	Life Insurance (426.2)											
47	Penalties (426.3)		(6,524)	7,578								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		234,056	188,837								
49	Other Deductions (426.5)		5,442,535	2,557,134								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		7,319,586	3,726,858								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	75,358	45,299								
53	Income Taxes-Federal (409.2)	262	(1,326,337)	(565,609)								
54	Income Taxes-Other (409.2)	262	(70,099)	(41,124)								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272		3,091,861								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272		2,108,512								
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)		(1,321,078)	421,915								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(2,646,766)	(2,638,500)								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		69,504,133	61,119,830								
63	Amort. of Debt Disc. and Expense (428)		773,406	560,777								
64	Amortization of Loss on Reaquired Debt (428.1)		33,650	33,651								
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)		6,186,117	7,125,967								
68	Other Interest Expense (431)		(8,851,602)	2,809,026								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		3,921,790	4,837,681								
70	Net Interest Charges (Total of lines 62 thru 69)		63,723,914	66,811,570								

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		36,861,721	33,961,853								
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)		36,861,721	33,961,853								
						Page 114-117						

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		377,534,237	343,572,384
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1	Adj to Retained Earnings			(1)
9	TOTAL Credits to Retained Earnings (Acct. 439)			(1)
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)		36,861,721	33,961,854
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)		414,395,958	377,534,237
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)		414,395,958	377,534,237
	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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	36,861,721	33,961,853
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	113,534,526	116,241,772
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Regulatory Debits and Credits (Net)	3,003,822	7,655,198
5.2	Mark-to-Market of Risk Management Contracts	(11,052,240)	14,298,790
8	Deferred Income Taxes (Net)	863,432	(26,058,745)
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	5,512,438	32,557,696
11	Net (Increase) Decrease in Inventory	22,428,695	(57,837,714)
12	Net (Increase) Decrease in Allowances Inventory	38,368	(55,276)
13	Net Increase (Decrease) in Payables and Accrued Expenses	2,272,539	(9,439,954)
14	Net (Increase) Decrease in Other Regulatory Assets	(16,271,627)	(29,511,557)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(2,150,128)	(7,877,872)
16	(Less) Allowance for Other Funds Used During Construction	2,033,764	967,911
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):	[(a)](7,385,593)	(1,482,291)
18.2	Customer Deposits	238,379	(757,480)
18.3	Over/Under Recovered Fuel, Net	2,053,224	12,614,668
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	147,913,792	83,341,177
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(194,559,376)	(162,549,442)
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	(2,033,764)	(967,911)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
31.2	Acquired Assets	(1,383)	(20,597)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(192,526,995)	(161,602,129)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	[(b)]197,559	114,902
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		
47	Collections on Loans		

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)
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Other (Provide details in footnote):		
53.2	(Increase) Decrease in Other Special Deposits	(93,410)	(461,193)
53.3	Proceed From Contribution in Aid of Construction Advance (CIAC)	1,159,425	802,020
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(191,263,421)	(161,146,400)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		465,000,000
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	(76,627)	(4,202,267)
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Proceed on Capital leaseback	1,384	20,598
67.2	Notes Payable to Associated Companies	133,644,908	
67.3	Capital Contributions from Parent	(701,806)	484,361
70	Cash Provided by Outside Sources (Total 61 thru 69)	132,867,860	461,302,692
72	Payments for Retirement of:		
73	Long-term Debt (b)	(90,000,000)	(340,000,000)
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		(44,860,167)
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)	42,867,860	76,442,524
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)	(481,769)	(1,362,698)
88	Cash and Cash Equivalents at Beginning of Period	1,321,222	2,683,920
90	Cash and Cash Equivalents at End of Period	839,453	1,321,222
Page 120-121			

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

	2024 Cash Flow Incr / (Decr)	2023 Cash Flow Incr / (Decr)
Utility Plant, Net	$ (8,463,875)	$ (15,198,453)
Property and Investments, Net	21,187	51,004
Special Funds	$ —	$ —
Margin Deposits	(1,120,770)	(1,520,459)
Mark-to-Market of Risk Management Contracts	—	
Prepayments	(2,733,320)	(4,671,828)
Accrued Utility Revenues, Net	(9,718,574)	35,002,399
Miscellaneous Current and Accr Assets	11,000,000	
Unamortized Debt Expense	676,281	549,589
Other Deferred Debits, Net	9,226,565	(14,643,409)
Proprietary Capital, Net	—	
Other Comprehensive Income, Net	—	
Unamortized Discount/Premium on Long-Term Debt	67,125	11,188
Accumulated Provisions - Misc	1,112,632	(513,191)
Current and Accrued Liabilities, Net	(9,645,004)	(2,782,266)
Other Deferred Credits, Net	2,192,160	2,233,135
Total	**$ (7,385,593)**	**$ (1,482,291)**

(b) Concept: ProceedsFromDisposalOfNoncurrentAssets

	2024 Cash Flow Incr / (Decr)	2023 Cash Flow Incr / (Decr)
Sale of GSU Transformer UTC 0000412037 SN 6123486 from WPCo/KPCo Mitchell Plant to I&M Cook Nuclear Plant	$ 72,941	$ —
Sale of Meters	4,793	7,920
Sale of Transformers	119,825	106,982
Total	**$ 197,559**	**$ 114,902**

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

NOTES TO FINANCIAL STATEMENTS

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

INDEX OF NOTES TO FINANCIAL STATEMENTS

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
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
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.
AEPSC	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.
ASU	Accounting Standards Update.
CCR	Coal Combustion Residual.
CWIP	Construction Work in Progress.
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.
KTCo	AEP Kentucky Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
Liberty	Liberty Utilities Co., a subsidiary of Algonquin Power & Utilities Corporation.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NOL	Net operating losses
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.
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.
Rockport Plant	A generation plant, jointly-owned by AEGCo and I&M, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana.
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 AEPSC 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.
UPA	Unit Power Agreement.
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.

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 163,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

Through May 2023, KPCo also had an affiliate agreement with I&M to purchase capacity from Rockport Plant, Unit 2 at a rate equal to PJM's RPM clearing price.

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 trued-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:

- 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 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.

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

	2024	2023
For the Years Ended December 31,	**(in thousands)**	
Cash was Paid (Received) for:		
Interest (Net of Capitalized Amounts)	$ 76,677	$ 60,986
Income Taxes (Net of Refunds)	982	(3,413)
Noncash Acquisitions Under Finance Leases	126	503
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	33,152	18,114

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	**2024**	**2023**
Percentage of Total Revenues	15 %	15 %
Percentage of Accounts Receivable – Customers	47 %	31 %

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. 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, 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.

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	67 %
Fixed Income	32 %
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 long and intermediate 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, 2024 and 2023, the fair value of securities on loan as part of the program was $60 million and $62 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2024 and 2023.

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).

Termination of Planned Disposition of KPCo and KTCo

In October 2021, AEP entered into a Stock Purchase Agreement (SPA) to sell KPCo and KTCo to Liberty Utilities Co., a subsidiary of Algonquin Power & Utilities Corp. (Liberty), for approximately a $2.85 billion enterprise value. The SPA was subsequently amended in September 2022 to reduce the purchase price to approximately $2.646 billion. The sale required approval from the KPSC and from the FERC under Section 203 of the Federal Power Act. The SPA contained certain termination rights if the closing of the sale did not occur by April 26, 2023.

In May 2022, the KPSC approved the sale of KPCo to Liberty subject to certain conditions contingent upon the closing of the sale. In December 2022, the FERC issued an order denying, without prejudice, authorization of the proposed sale stating the applicants failed to demonstrate the proposed transaction will not have an adverse effect on rates. In February 2023, a new filing for approval under Section 203 of the Federal Power Act was submitted. In March 2023, the KPSC and other intervenors made filings recommending the FERC reject AEP and Liberty's new Section 203 application seeking approval of the sale.

In April 2023, AEP, AEPTCo and Liberty entered into a Mutual Termination Agreement (Termination Agreement) terminating the SPA. The parties entered into the Termination Agreement as all of the conditions precedent to closing the sale could not be satisfied prior to April 26, 2023.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2024 through February 13, 2025, the date that KPCo's 2024 Annual Report was available to be issued, and has updated such evaluation for disclosure purposes through April 8, 2025. 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 standard 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.

The amendments in the new standard may be applied on either a prospective or retrospective basis for public business entities for fiscal years beginning after December 15, 2024 with early adoption permitted. Management has concluded to adopt the amendments to this standard prospectively beginning on January 1, 2025.

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 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. As of December 31, 2024, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $547.3 million. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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 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 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, challenging among other aspects of the order, the $14.2 million base rate revenue requirement reduction. In January 2025, the Commonwealth of Kentucky Franklin 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 January 2024, consistent with the November 2023 uncontested settlement agreement, the KPSC issued a financing order approving KPCo's request to securitize certain regulatory assets balances as of the time securitization bonds are issued and concluding that costs requested for recovery through securitization were prudently incurred. The KPSC's financing order includes certain additional requirements related to securitization bond structuring, marketing, placement and issuance that were not reflected in KPCo's proposal. In accordance with Kentucky statutory requirements and the financing order, the issuance of the securitized bonds is subject to final review by the KPSC after bond pricing. KPCo expects to proceed with the securitized bond issuance process and to complete the securitization process in the first half of 2025, subject to market
conditions. As of December 31, 2024, regulatory asset balances expected to be recovered through securitization total $490.6 million and include: (a) $302.5 million of plant retirement costs, (b) $78.7 million of deferred storm costs related to 2020, 2021, 2022 and 2023 major storms, (c) $49.7 million of deferred purchased power expenses, (d) $57.4 million of under-recovered purchased power rider costs and (e) $2.3 million of deferred issuance-related expenses, including KPSC advisor expenses. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Fuel Adjustment Clause (FAC) Review

In December 2023, KPCo received intervenor testimony in its FAC review for the two-year period ending October 31, 2022, recommending a disallowance ranging from $44.3 million to $59.8 million of its total $432.3 million purchased power cost recoveries as a result of proposed modifications to the ratemaking methodology that limits purchased power costs recoverable through the FAC. In November 2024, KPCo and intervening parties entered into a settlement agreement whereby KPCo agreed to provide customer rate credits, which will reduce FAC costs otherwise recoverable in 2025 and 2026, for a combined $16.9 million over the periods January 2025 through April 2025 and January 2026 through April 2026 based on actual customer usage. In December 2024, the KPSC issued an order approving the settlement agreement without modification.

Rockport Offset Recovery

In January 2024, KPCo filed an application with the KPSC seeking to recover an allowed cost (Rockport Offset) of $40.8 million in accordance with the terms of the settlement agreement in the 2017 Kentucky Base Rate Case permitting KPCo to use the level of non-fuel, non-environmental Rockport Plant UPA expense included in base rates to earn its authorized ROE in 2023 since the Rockport UPA ended in December 2022. An estimated Rockport Offset of $22.8 million was recovered through a rider, subject to true-up, during the 12-months ended December 2023. In February 2024, the KPSC issued an order allowing KPCo to collect the remaining $18 million through interim rates, subject to refund, over twelve months starting in March 2024. In August 2024, KPCo filed an application with the KPSC to extend the recovery of the remaining balance through September 2025. In the fourth quarter of 2024, the KPSC issued orders approving KPCo's application to extend recovery of the Rockport Offset and affirming collection of $18 million.

2024 Storm Costs

In April and May 2024, severe storms impacted KPCo's service territory resulting in customer outages and damage to KPCo utility assets. Consistent with prior guidance from the KPSC, in July 2024, KPCo filed a request with the KPSC seeking authority to defer $4.1 million of incremental other operation and maintenance expenses related to service restoration efforts. In September 2024, the KPSC approved KPCo's request for deferral authority of the April and May 2024 storm-related costs. KPCo will seek recovery of the deferred storm costs in its next base rate case.

In late September 2024, the remnants of Hurricane Helene impacted KPCo's service territory resulting in customer outages and damage to KPCo utility assets. Consistent with prior guidance from the KPSC, in October 2024, KPCo filed a request with the KPSC seeking authority to defer $6.4 million of incremental other operation and maintenance expenses related to service restoration efforts. In December 2024, the KPSC approved KPCo's request for deferral authority of the September 2024 storm-related costs. KPCo will seek recovery of the deferred storm costs in its next base rate case.

If any of these incremental storm costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

4. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2024	December 31, 2023	Remaining Recovery Period
	(in thousands)		
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs (a)	$ 89,543	$ 78,759	
Other Regulatory Assets Pending Final Regulatory Approval	3,840	1,259	
Total Regulatory Assets Pending Final Regulatory Approval	93,383	80,018	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs	180,907	171,214	16 years
Plant Retirement Costs - Asset Retirement Obligation Costs	110,510	110,280	16 years
Kentucky Deferred Purchased Power Expenses	45,011	43,512	3 years
Other Regulatory Assets Approved for Recovery	3,965	4,299	various
Total Regulatory Assets Currently Earning a Return	340,393	329,305	
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets	146,057	145,573	(b)
Fuel and Purchased Power Rider	57,373	61,376	2 years
Pension and OPEB Funded Status	13,726	24,570	12 years
Under-recovered Fuel Costs	8,635	10,688	1 year
Unrealized Loss on Forward Commitments	8	10,038	3 years
Plant Retirement Costs - Asset Retirement Obligation Costs	52,294	—	16 years
Other Regulatory Assets Approved for Recovery	19,663	20,823	various
Total Regulatory Assets Currently Not Earning a Return	297,756	273,068	
Total Regulatory Assets Approved for Recovery	638,149	602,373	
Total FERC Account 182.3 Regulatory Assets	$ 731,532	$ 682,391	

(a) $78.7 million of deferred storm costs related to 2020, 2021, 2022 and 2023 major storms are expected to be recovered through securitization. KPCo will seek recovery of remaining costs during the next base rate case.
(b) Recovered over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets.

Regulatory Liabilities:	December 31, 2024	December 31, 2023	Remaining Refund Period
	(in thousands)		
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes Liabilities (a)	114,951	123,778	(b)
Total Regulatory Liabilities Currently Paying a Return	114,951	123,778	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Approved for Payment	5,215	4,756	various
Total Regulatory Liabilities Currently Not Paying a Return	5,215	4,756	
Total Regulatory Liabilities Approved for Payment	120,166	128,534	
Total FERC Account 254 Regulatory Liabilities	$ 120,166	$ 128,534	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets.

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, 2024:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 5,993	$ 11,985	$ 12,002	$ 8,472	$ 38,452
Energy and Capacity Purchase Contracts	1,521	1,085	—	—	2,606
Total	$ 7,514	$ 13,070	$ 12,002	$ 8,472	$ 41,058

(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, 2024, there were no material liabilities recorded for any indemnifications. AEPSC 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 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 existing 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 revised CCR Rule.

Increase in ARO	Increase in Generation Property (a)	Increase in Regulatory Asset (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.

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, 2024, 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, 2024, 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.

In July 2024, KPCo renewed its insurance programs including coverage for wildfire liability. 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 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 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:

	Pension Plans		OPEB	
	December 31,			
Assumptions	2024	2023	2024	2023
Discount Rate	5.65 %	5.15 %	5.60 %	5.15 %
Interest Crediting Rate	4.55 %	4.00 %	NA	NA
Rate of Compensation Increase	5.75 % (a)	5.15 % (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 2024, 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 5.75%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans		OPEB	
	Year Ended December 31,			
Assumptions	**2024**	**2023**	**2024**	**2023**
Discount Rate	5.20 %	5.50 %	5.15 %	5.50 %
Interest Crediting Rate	4.05 %	4.25 %	NA	NA
Expected Return on Plan Assets	7.30 %	7.50 %	6.75 %	7.25 %
Rate of Compensation Increase	5.25 % (a)	5.15 % (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:

	December 31,	
Health Care Trend Rates	**2024**	**2023**
Initial	6.50 %	7.00 %
Ultimate	4.50 %	4.50 %
Year Ultimate Reached	2029	2030

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 ensure compliance with the investment policy. As of December 31, 2024, 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, 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. For the year ended December 31, 2023, the pension plans had an actuarial loss primarily due to a decrease in the discount rate, and to a lesser extent the effect of demographic experience (updated census data on January 1, 2023). These losses were partially offset by decreasing the cash balance account interest crediting rate. For the year ended December 31, 2023, the OPEB plans had an actuarial loss primarily due to discount rates, as well as actual net benefit payments above expected. These losses were partially offset by updated per capita cost assumptions. 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 and obligation, respectively.

	Pension Plans		OPEB	
	2024	**2023**	**2024**	**2023**
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1,	$ 92,174	$ 86,855	$ 23,129	$ 23,605
Service Cost	1,604	1,474	56	63
Interest Cost	6,127	4,814	1,373	1,269
Actuarial (Gain) Loss	28,735	5,833	(2,491)	1,335
Settlements	(6,023)	—	—	—
Special/Contractual Termination Benefits	—	—	94	—
Benefit Payments	(8,339)	(6,802)	(3,996)	(4,619)
Participant Contributions	—	—	1,765	1,470
Medicare Subsidy	—	—	6	6
Benefit Obligation as of December 31,	$ 114,278	$ 92,174	$ 19,936	$ 23,129
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 87,421	$ 83,062	$ 47,872	$ 44,136
Actual Gain on Plan Assets	36,219	11,161	12,618	6,884
Company Contributions	—	—	2	1
Participant Contributions	—	—	1,765	1,470
Settlements	(6,023)	—	—	—
Benefit Payments	(8,339)	(6,802)	(3,996)	(4,619)
Fair Value of Plan Assets as of December 31,	$ 109,278	$ 87,421	$ 58,261	$ 47,872
Funded (Underfunded) Status as of December 31,	$ (5,000)	$ (4,753)	$ 38,325	$ 24,743

Amounts Recognized on the Balance Sheets

	Pension Plans		OPEB	
	December 31,			
	2024	**2023**	**2024**	**2023**
	(in thousands)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ —	$ —	$ 38,325	$ 24,743
Other Current Liabilities – Accrued Short-term Benefit Liability	—	(21)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(5,000)	(4,732)	—	—
Funded (Underfunded) Status	$ (5,000)	$ (4,753)	$ 38,325	$ 24,743

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:

	Pension Plans		OPEB	
	December 31,			
	2024	**2023**	**2024**	**2023**
Components	(in thousands)			
Net Actuarial (Gain) Loss	$ 18,945	$ 18,788	$ (4,812)	$ 6,561
Prior Service Credit	—	—	(407)	(780)
Recorded as				
Regulatory Assets	$ 18,945	$ 18,789	$ (5,219)	$ 5,781
Deferred Income Taxes	—	(1)	—	—

Components	Pension Plans 2024		Pension Plans 2023		OPEB 2024		OPEB 2023	
	(in thousands)							
Actuarial (Gain) Loss During the Year	$	1,939	$	1,803	$	(11,256)	$	(2,348)
Amortization of Actuarial Loss		(93)		—		(118)		(445)
Amortization of Prior Service Credit		—		—		374		1,856
Amounts Recognized Due to Settlement		(1,689)		—		—		—
Transfers - Prior Service Cost		—		—		(1)		1
Transfers - (Gain)/loss		—		—		1		(1)
Change for the Year Ended December 31,	$	157	$	1,803	$	(11,000)	$	(937)

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,			
2024	2023	2024	2023
3.0 %	2.1 %	3.3 %	2.9 %

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		Other		Total		Year End Allocation
	(in millions)										
Equities (a):											
Domestic	$	327.0	$	—	$	—	$	—	$	327.0	8.9 %
International		290.2		—		—		—		290.2	7.9 %
Common Collective Trusts (b)		176.1		—		—		472.6		648.7	17.7 %
Subtotal – Equities		793.3		—		—		472.6		1,265.9	34.5 %
Fixed Income (a):											
United States Government and Agency Securities		(2.3)		865.6		—		—		863.3	23.6 %
Corporate Debt		—		719.2		—		—		719.2	19.6 %
Foreign Debt		—		136.1		—		—		136.1	3.7 %
State and Local Government		—		25.8		—		—		25.8	0.7 %
Other – Asset Backed		—		0.9		—		—		0.9	— %
Subtotal – Fixed Income		(2.3)		1,747.6		—		—		1,745.3	47.6 %
Infrastructure (b)		—		—		—		112.9		112.9	3.1 %
Real Estate (b)		—		—		—		227.9		227.9	6.2 %
Alternative Investments (b)		—		—		—		223.8		223.8	6.1 %
Cash and Cash Equivalents (b)		—		41.3		—		27.2		68.5	1.9 %
Other – Pending Transactions and Accrued Income (c)		—		—		—		21.9		21.9	0.6 %
Total	$	791.0	$	1,788.9	$	—	$	1,086.3	$	3,666.2	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	$	616.8	$	—	$	—	$	—	$	616.8	34.7 %
International		267.2		—		—		—		267.2	15.0 %
Common Collective Trusts (a)		64.2		—		—		129.4		193.6	10.9 %
Subtotal – Equities		948.2		—		—		129.4		1,077.6	60.6 %
Fixed Income:											
Common Collective Trust – Debt (a)		—		—		—		132.9		132.9	7.5 %
United States Government and Agency Securities		(0.5)		157.6		—		—		157.1	8.9 %
Corporate Debt		—		132.3		—		—		132.3	7.5 %
Foreign Debt		—		27.1		—		—		27.1	1.5 %
State and Local Government		57.8		5.0		—		—		62.8	3.5 %
Other – Asset Backed		—		0.2		—		—		0.2	— %
Subtotal – Fixed Income		57.3		322.2		—		132.9		512.4	28.9 %
Trust Owned Life Insurance:											
International Equities		—		23.1		—		—		23.1	1.3 %
United States Bonds		—		118.2		—		—		118.2	6.7 %
Subtotal – Trust Owned Life Insurance		—		141.3		—		—		141.3	8.0 %
Cash and Cash Equivalents (a)		27.6		—		—		3.1		30.7	1.7 %
Other – Pending Transactions and Accrued Income (b)		—		—		—		13.9		13.9	0.8 %
Total	$	1,033.1	$	463.5	$	—	$	279.3	$	1,775.9	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, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 411.3	$ —	$ —	$ —	$ 411.3	10.0 %
International	389.8	—	—	—	389.8	9.5 %
Common Collective Trusts (b)	—	—	—	420.9	420.9	10.2 %
Subtotal – Equities	801.1	—	—	420.9	1,222.0	29.7 %
Fixed Income (a):						
United States Government and Agency Securities	8.3	1,099.2	—	—	1,107.5	26.9 %
Corporate Debt	—	894.8	—	—	894.8	21.7 %
Foreign Debt	—	167.1	—	—	167.1	4.1 %
State and Local Government	—	38.7	—	—	38.7	0.9 %
Other – Asset Backed	—	1.3	—	—	1.3	— %
Subtotal – Fixed Income	8.3	2,201.1	—	—	2,209.4	53.6 %
Infrastructure (b)	—	—	—	101.4	101.4	2.5 %
Real Estate (b)	—	—	—	239.3	239.3	5.8 %
Alternative Investments (b)	—	—	—	241.8	241.8	5.8 %
Cash and Cash Equivalents (b)	—	51.0	—	33.8	84.8	2.1 %
Other – Pending Transactions and Accrued Income (c)	—	—	0.1	19.4	19.5	0.5 %
Total	$ 809.4	$ 2,252.1	$ 0.1	$ 1,056.6	$ 4,118.2	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, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 540.6	$ —	$ —	$ —	$ 540.6	32.3 %
International	288.4	—	—	—	288.4	17.2 %
Common Collective Trusts (a)	—	—	—	131.6	131.6	7.9 %
Subtotal – Equities	829.0	—	—	131.6	960.6	57.4 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	146.7	146.7	8.8 %
United States Government and Agency Securities	1.4	163.3	—	—	164.7	9.8 %
Corporate Debt	—	149.0	—	—	149.0	8.9 %
Foreign Debt	—	28.6	—	—	28.6	1.7 %
State and Local Government	41.5	7.8	—	—	49.3	3.0 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.9	348.9	—	146.7	538.5	32.2 %
Trust Owned Life Insurance:						
International Equities	—	22.3	—	—	22.3	1.3 %
United States Bonds	—	130.0	—	—	130.0	7.8 %
Subtotal – Trust Owned Life Insurance	—	152.3	—	—	152.3	9.1 %
Cash and Cash Equivalents (a)	25.9	—	—	2.9	28.8	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(6.9)	(6.9)	(0.4)%
Total	$ 897.8	$ 501.2	$ —	$ 274.3	$ 1,673.3	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, 2024	2023
	(in thousands)	
Qualified Pension Plan	$ 111,430	$ 89,419
Nonqualified Pension Plan	17	7
Total Accumulated Benefit Obligation	$ 111,447	$ 89,426

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, 2024	2023
	(in thousands)	
Projected Benefit Obligation	$ 114,278	$ 92,174
Fair Value of Plan Assets	109,278	87,421
Underfunded Projected Benefit Obligation	$ (5,000)	$ (4,753)

Accumulated Benefit Obligation

	Underfunded Pension Plans December 31, 2024	2023
	(in thousands)	
Accumulated Benefit Obligation	$ 111,447	$ 89,426
Fair Value of Plan Assets	109,278	87,421
Underfunded Accumulated Benefit Obligation	$ (2,169)	$ (2,005)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the Pension and OPEB plans of $2.1 million and $8 thousand, respectively, during 2025. 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)	
2025	$ 10,321	$ 4,232
2026	9,859	4,032
2027	10,430	3,833
2028	9,849	3,620
2029	9,810	3,509
Years 2030 to 2034, in Total	44,623	15,675

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,			
	2024	2023	2024	2023
	(in thousands)			
Service Cost	$ 1,604	$ 1,474	$ 56	$ 63
Interest Cost	6,127	4,814	1,373	1,269
Expected Return on Plan Assets	(9,422)	(7,131)	(3,853)	(3,201)
Amortization of Prior Service Credit	—	—	(374)	(1,856)
Amortization of Net Actuarial Loss	93	—	118	445
Settlements	1,689	—	—	—
Net Periodic Benefit Cost (Credit)	91	(843)	(2,680)	(3,280)
Capitalized Portion	(868)	(812)	(30)	(35)
Net Periodic Benefit Credit Recognized in Expense	$ (777)	$ (1,655)	$ (2,710)	$ (3,315)

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 $1.4 million in 2024 and $1.4 million in 2023.

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.

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

Primary Risk Exposure	December 31, 2024	2023	Unit of Measure
	(in thousands)		
Commodity:			
Power	4,832	3,303	MWhs
Natural Gas	9,783	9,761	MMBtus
Heating Oil and Gasoline	48	253	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 $395 thousand and $1.2 million as of December 31, 2024 and 2023, respectively. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets as of December 31, 2024 and 2023.

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

Statement of Financial Position Location	December 31, 2024 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	$ 6,775	$ (1,084)	$ 5,691
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

Balance Sheet Location	December 31, 2023 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	$ 3,590	$ (511)	$ 3,079
Long-term Portion of Derivative Instrument Assets	230	(215)	15
Derivative Instrument Liabilities	10,564	(1,664)	8,900
Long-term Portion of Derivative Instrument Liabilities	1,189	(215)	974

(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, 2024	2023
	(in thousands)	
Operating Revenues	$ 3	$ 1
Operation Expenses	96	77
Maintenance Expenses	(4)	—
Other Regulatory Assets (a)	10,023	(10,043)
Other Regulatory Liabilities (a)	8,536	1,209
Total Gain (Loss) on Risk Management Contracts	$ 18,654	$ (8,756)

(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."

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), KPCo initially reports the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income on the balance sheets until the period the hedged item affects Net Income.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Operating Revenues or Operation Expenses on KPCo's statements of income, or in Other Regulatory Assets or Other Regulatory Liabilities on KPCo's balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2024 and 2023, KPCo did not apply cash flow hedging to outstanding power derivatives.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income on its balance sheets into Interest on Long-Term Debt on its statements of income in those periods in which hedged interest payments occur. During the years ended 2024 and 2023, KPCo did not apply cash flow hedging to outstanding interest rate derivatives.

There was no impact of cash flow hedges included in Accumulated Other Comprehensive Income on KPCo's balance sheets as of December 31, 2024 and 2023.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income to Net Income can differ due to market price changes. As of December 31, 2024, KPCo is not hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions.

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, 2024 and 2023, 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, 2024 and 2023. 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 $212 thousand and $8 million, and no cash collateral posted as of December 31, 2024 and 2023, 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,			
	2024		2023	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 1,214,407	$ 1,222,803	$ 1,304,340	$ 1,302,987

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, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:	(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

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2023

	Level 1	Level 2	Level 3	Other	Total
Assets:	(in thousands)				
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 283	$ 3,111	$ (315)	$ 3,079
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 9,771	$ 597	$ (1,468)	$ 8,900

(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, 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	$ 4,831

Year Ended December 31, 2023	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2022	$ 8,463
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(62)
Settlements	(8,401)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	2,514
Balance as of December 31, 2023	$ 2,514

(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, 2024 and 2023:

Significant Unobservable Inputs
December 31, 2024

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

Significant Unobservable Inputs
December 31, 2023

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted (b)
	(in thousands)						
FTRs	$ 3,111	$ 597	Discounted Cash Flow	Forward Market Price	$ (0.03)	$ 5.05	$ 0.82

(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, 2024 and 2023:

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. <u>INCOME TAXES</u>

Income Tax Expense (Benefit)

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

	Years Ended December 31, 2024	2023
	(in thousands)	
Charged (Credited) to Operating Expense, Net:		
Current	$ 3,514	$ (1,009)
Deferred	863	(27,042)
Total	4,377	(28,051)
Charged (Credited) to Non-Operating Income, Net:		
Current	(1,396)	(607)
Deferred	—	983
Total	(1,396)	376
Income Tax Expense (Benefit)	$ 2,981	$ (27,675)

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, 2024	2023
	(in thousands)	
Net Income	$ 36,862	$ 33,962
Income Tax Expense (Benefit)	2,981	(27,675)
Pretax Income	$ 39,843	$ 6,287
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 8,367	$ 1,320
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Reversal of Original Flow-Through	840	972
Removal Costs	1,668	(2,587)
State and Local Income Taxes, Net	(818)	(397)
Tax Reform Excess ADIT Reversal	(6,626)	(25,944)
Federal Return to Provision Adjustment	—	(560)
AFUDC Equity	(422)	(195)
Other	(28)	(284)
Income Tax Expense (Benefit)	$ 2,981	$ (27,675)
Effective Income Tax Rate	7.5 %	(440.2) %

Net Deferred Tax Liability

The following table shows elements of KPCo's net deferred tax liability and significant temporary differences. Amounts presented for 2023 were recast to allocate "Deferred State Income Taxes", and other miscellaneous temporary differences, amongst other categories to substantively reflect the elements of the net deferred tax liability.

	December 31, 2024	2023
	(in thousands)	
Deferred Tax Assets	$ 82,133	$ 74,967
Deferred Tax Liabilities	(566,150)	(548,810)
Net Deferred Tax Liabilities	$ (484,017)	$ (473,843)
Property Related Temporary Differences	$ (371,937)	$ (379,093)
Amounts Due to Customers for Future Income Taxes	28,689	30,889
Tax Credit Carryforward	3,030	22
Net Operating Loss Carryforward	13,016	12,345
Regulatory Assets	(155,750)	(140,858)
All Other, Net	(1,065)	2,852
Net Deferred Tax Liabilities	$ (484,017)	$ (473,843)

Federal 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 2017. KPCo and other AEP subsidiaries agreed to extend the SOL on the 2017-2020 tax returns to May 31, 2025, to allow the Congressional Joint Committee on Taxation ("JCT") adequate time to complete its review of the now closed IRS audit. Following JCT's approval, KPCo and other AEP subsidiaries received IRS confirmation that tax years 2017-2020 are now effectively closed as they only remain open for changes to other non-consolidated entities that KPCo and other AEP subsidiaries hold an interest in.

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 2017. 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 has state net income tax operating loss carryforwards of $178 million in 2024. As a result, KPCo recognized deferred state income tax benefits in 2024 of $9 million. This is consistent with the net operating loss carryforwards and deferred state income tax benefits recognized in 2023. Management anticipates future taxable income will be sufficient to realize the state net income tax operating loss tax benefits before the state carryforward begins expiring in 2035.

10. <u>LEASES</u>

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, 2024	2023
	(in thousands)	
Operating Lease Cost	$ 258	$ 71
Finance Lease Cost:		
Amortization of Finance Leases	118	83
Interest on Finance Leases	55	22
Total Lease Rental Costs (a)	$ 431	$ 176

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

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

Lease Type	Weighted-Average Remaining Lease Term (years):		Weighted-Average Discount Rate	
	December 31,			
	2024	2023	2024	2023
Operating Leases	4.51	5.10	5.42 %	3.49 %
Finance Leases	7.17	7.34	6.52 %	6.13 %

	Years Ended December 31, 2024	2023
	(in thousands)	
Cash Paid for Amounts Included in the Measurement of Lease Liabilities		
Operating Cash Flows Used for Operating Leases	$ 258	$ 71
Operating Cash Flows Used for Finance Leases	176	105
Non-cash Acquisitions Under Operating Leases	$ 844	$ 639

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 one month:

	December 31, 2024	2023
	(in thousands)	
Property, Plant and Equipment Under Finance Leases		
Utility Plant (a)	$ 914	$ 789
Obligations Under Finance Leases		
Noncurrent	779	677
Current	135	112
Total Obligations Under Finance Leases	$ 914	$ 789

(a) Includes $415 thousand and $292 thousand of accumulated provision for depreciation and amortization for the years ended December 31, 2024 and 2023, respectively.

	December 31, 2024	2023
	(in thousands)	
Property, Plant and Equipment Under Operating Leases		
Utility Plant (a)	$ 1,968	$ 1,115
Obligations Under Operating Leases		
Noncurrent	1,795	963
Current	216	195
Total Obligations Under Operating Leases	$ 2,011	$ 1,158

(a) Includes $368 thousand and $189 thousand of accumulated provision for depreciation and amortization for the years ended December 31, 2024 and 2023, respectively.

Future minimum lease payments consisted of the following as of December 31, 2024:

Future Minimum Lease Payments	Finance Leases	Operating Leases
	(in thousands)	
2025	$ 193	$ 465
2026	180	472
2027	164	450
2028	123	432
2029	110	313
After 2029	396	199
Total Future Minimum Lease Payments	1,166	2,331
Less: Imputed Interest	253	320
Estimated Present Value of Future Minimum Lease Payments	$ 913	$ 2,011

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, 2024, the maximum potential loss for these lease agreements was $121 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, 2024 and December 31, 2023, 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, 2024	Interest Rate Ranges as of December 31, 2024	2023	Outstanding as of December 31, 2024	2023
					(in thousands)	
Senior Unsecured Notes	2026-2047	5.55%	3.35%-8.13%	3.13%-8.13%	$ 1,000,000	$ 1,065,000
Pollution Control Bonds	2026 (a)	4.70%	4.70%	4.70%	65,000	65,000
Notes Payable - Affiliated		—%	—%	5.29%	—	25,000
Other Long-term Debt	2025	5.42%	5.42%	6.41%	150,000	150,000
Unamortized Discount, Net					(593)	(660)
Total Long-term Debt					$ 1,214,407	$ 1,304,340

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

As of December 31, 2024, outstanding long-term debt was payable as follows:

	2025	2026	2027	2028	2029	After 2029	Total
				(in thousands)			
Principal Amount	$ 150,000	$ 265,000	$ 40,000	$ —	$ 195,000	$ 565,000	$ 1,215,000
Unamortized Discount, Net							(593)
Total Long-term Debt							$ 1,214,407

Long-term Debt Subsequent Event

In January 2025, KPCo entered into a $150 million term loan due in February 2026.

Financing Plan

As of December 31, 2024, the balance sheet of KPCo reflects negative working capital primarily driven by Notes Payable to Associated Companies and Accounts Payable. In January 2025, KPCo entered into a $150 million term loan to provide additional liquidity. In January 2024, the KPSC issued a financing order approving KPCo's request to securitize certain regulatory assets. KPCo expects to proceed with the securitized bond issuance process and to complete the securitization process in the first half of 2025, subject to market conditions. If completed, the securitization will provide KPCo recovery of approximately $491 million of regulatory assets; however, there is no guarantee this will occur. Accordingly, Parent, having available liquidity, has committed to provide sufficient liquidity to KPCo, as necessary, to continue operations and meet obligations as they become due until KPCo is able to execute its upcoming financing plan. Therefore, management does not believe there is a substantial doubt about KPCo's ability to continue as a going-concern and the KPCo financial statements have been prepared on a going-concern basis, which contemplates the realization of assets and the satisfaction of obligations in the normal course of business.

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, 2024, 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, 2024, 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 $671.9 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, 2024, the amount of any such restrictions was $95.4 million.

Corporate Borrowing Program – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2024 and 2023 are included in Notes Payable to Associated Companies 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	Borrowings from the Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2024	$ 206,113	$ —	$ 93,082	$ —	$ 183,212	$ 250,000
2023	169,398	243,803	112,116	243,764	49,567	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
2024	5.79 %	4.74 %	— %	— %	5.27 %	— %
2023	5.81 %	4.66 %	5.72 %	5.72 %	5.53 %	5.72 %

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, 2024	2023
	(in thousands)	
Interest Expense	$ 5,345	$ 6,399
Interest Income	—	116

Securitized Accounts Receivables – AEP Credit

Under an affiliated receivables sales arrangement, KPCo sold, without recourse, certain of its customer accounts receivable and accrued utility revenues balances to AEP Credit. In January 2022, due to the expected sale to Liberty, KPCo ceased selling accounts receivable to AEP Credit. As a result, in the first quarter of 2022, KPCo began recording an allowance for uncollectible accounts on its balance sheet for those receivables no longer sold to AEP Credit. In September 2023, KPCo resumed selling accounts receivable to AEP Credit, due to the termination of the sale to Liberty, and the balance in KPCo's allowance for uncollectible accounts was reversed. 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 2026. As of December 31, 2024, 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 $53.4 million and $42.7 million as of December 31, 2024 and 2023, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $5.0 million and $1.9 million for the years ended December 31, 2024 and 2023, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $642.8 million and $205.3 million for the years ended December 31, 2024 and 2023, 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.

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 $418 thousand and $177 thousand for the years ended December 31, 2024 and 2023, 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, 2024 and 2023 were not material. These sales and purchases are recorded in Utility Plant on the balance sheets.

Unit Power Agreements

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all of its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The UPA will continue in effect until the debt obligations of AEGCo secured by the Rockport Plant have been satisfied and discharged (currently expected to be December 2028).

In April 2021, AEGCo and I&M executed an agreement to purchase 100% of the interests in Rockport Plant, Unit 2 effective at the end of the lease term on December 7, 2022. Beginning December 8, 2022, AEGCo and I&M applied the joint plant accounting model to their respective 50% undivided interests in the jointly owned Rockport Plant, Unit 2 as well as any future investments made prior to the current estimated retirement date of December 2028.
Prior to the termination of the lease, I&M assigned 30% of the power to KPCo as part of a UPA between AEGCo and KPCo. Beginning December 8, 2022, AEGCo billed 100% of its share of the Rockport Plant to I&M and ceased billing to KPCo. KPCo reached an agreement with I&M, from the end of the lease through May 2023, to buy capacity from Rockport Plant, Unit 2 through the PCA at a rate equal to PJM's RPM clearing price. KPCo's direct purchases from AEGCo were $373 thousand and $2 million for the years ended December 31, 2024 and 2023, respectively. These direct purchases are presented as Operation Expenses on the statements of income.

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, 2024 and 2023 were $75.5 million and $66 million, respectively, and were recorded in Operation Expenses on KPCo's statements of income.

Affiliated Revenues

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

	Years Ended December 31,	
Related Party Revenues	**2024**	**2023**
	(in thousands)	
Transmission Agreement Sales	$ 13,283	$ 10,038
Other Revenues	1,229	1,135
Total Affiliated Revenues	$ 14,512	$ 11,173

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 2024 and 2023.

Year	Steam	Transmission	Distribution	General
		(in percentages)		
2024	2.7 %	2.5 %	3.4 %	8.5 %
2023	3.3 %	2.7 %	3.4 %	8.6 %

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 2024 and 2023 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)			
2024	$ 18,276	$ 2,587	$ 66,399	$ (924)	$ 2,495	$ 88,833
2023	18,477	811	—	(1,088)	76	18,276

(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, 2024					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,088,611	$ 3,680	$ 545,520
KPCo's Share as of December 31, 2023					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,055,915	$ 21,596	$ 534,308

(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,	
	2024	2023
	(in thousands)	
Retail Revenues:		
Residential Revenues	$ 278,699	$ 246,124
Commercial Revenues	190,145	159,443
Industrial Revenues	167,490	149,336
Other Retail Revenues	2,147	1,979
Total Retail Revenues	638,481	556,882
Wholesale Revenues:		
Generation Revenues	23,662	20,812
Transmission Revenues (a)	30,070	28,799
Total Wholesale Revenues	53,732	49,611
Other Revenues from Contracts with Customers (b)	11,486	11,176
Total Revenues from Contracts with Customers	703,699	617,669
Other Revenues:		
Alternative Revenue Programs (c)	2,880	5,052
Other Revenues	3	1
Total Other Revenues	2,883	5,053
Total Operating Revenues	$ 706,582	$ 622,722

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues were $13.8 million and $17 million for years ended December 31, 2024 and 2023, 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, 2024. 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.

2025	2026-2027	2028-2029	After 2029	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, 2024 and 2023, respectively.

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, 2024 and 2023, respectively.

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, 2024 and 2023, respectively. 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 $14.1 million and $12.2 million, respectively, as of December 31, 2024 and December 31, 2023.

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, 2024 and 2023, respectively.

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year									
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)								33,961,853	33,961,853
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)								36,861,721	36,861,721
10	Balance of Account 219 at End of Current Quarter/Year									

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	3,319,600,129	3,319,600,129					
4	Property Under Capital Leases	2,882,654	2,882,654					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	291,077,800.00	291,077,800.00					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	3,613,560,583	3,613,560,583					
9	Leased to Others							
10	Held for Future Use	801,671	801,671					
11	Construction Work in Progress	117,585,328	117,585,328					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	3,731,947,582	3,731,947,582					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,368,455,314	1,368,455,314					
15	Net Utility Plant (13 less 14)	2,363,492,268	2,363,492,268					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	1,336,283,179	1,336,283,179					
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	32,172,135	32,172,135					
22	Total in Service (18 thru 21)	1,368,455,314	1,368,455,314					
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)	1,368,455,314	1,368,455,314					

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents	52,919					52,919
4	(303) Miscellaneous Intangible Plant	60,894,415	5,118,926	9,190,306			56,823,035
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	60,947,334	5,118,926	9,190,306			56,875,954
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	4,859,778	126,334				4,986,112
9	(311) Structures and Improvements	81,952,866	22,190,500	1,842,061			102,301,305
10	(312) Boiler Plant Equipment	972,789,844	12,785,698	6,435,324			979,140,218
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	121,751,934	1,353,326	2,235,440			120,869,820
13	(315) Accessory Electric Equipment	32,777,792	1,961,744	144,603			34,594,933
14	(316) Misc. Power Plant Equipment	14,093,917	311,233	87,427			14,317,723
15	(317) Asset Retirement Costs for Steam Production	11,312,853	22,728,672				34,041,525
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,239,538,984	61,457,507	10,744,855			1,290,251,636
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						
20	(322) Reactor Plant Equipment						
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
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						
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)						
36	D. Other Production Plant						
37	(340) Land and Land Rights						
38	(341) Structures and Improvements						
39	(342) Fuel Holders, Products, and Accessories						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
40	(343) Prime Movers						
41	(344) Generators						
42	(345) Accessory Electric Equipment						
43	(346) Misc. Power Plant Equipment						
44	(347) Asset Retirement Costs for Other Production						
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)						
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,239,538,984	61,457,507	10,744,855			1,290,251,636
47	3. Transmission Plant						
48	(350) Land and Land Rights	40,025,350	5,956,798				45,982,148
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	16,877,997	13,164,471	88,560			29,953,908
50	(353) Station Equipment	291,476,769	22,993,829	1,858,647			312,611,951
51	(354) Towers and Fixtures	101,216,713	23,042,714	118,653			124,140,774
52	(355) Poles and Fixtures	212,039,911	34,930,674	3,250,705			243,719,880
53	(356) Overhead Conductors and Devices	171,266,189	17,060,360	272,123			188,054,426
54	(357) Underground Conduit	4,863,115	998,834				5,861,949
55	(358) Underground Conductors and Devices	497,623	64,343				561,966
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)	838,263,667	118,212,023	5,588,688			950,887,002
59	4. Distribution Plant						
60	(360) Land and Land Rights	9,772,001	2,200,701				11,972,702
61	(361) Structures and Improvements	11,986,226	7,236,749	1,483			19,221,492
62	(362) Station Equipment	149,829,164	21,250,908	895,078			170,184,994
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	306,949,264	23,310,479	1,657,504			328,602,239
65	(365) Overhead Conductors and Devices	324,443,634	16,051,304	1,468,727			339,026,211
66	(366) Underground Conduit	9,986,143	139,874	2,140			10,123,877
67	(367) Underground Conductors and Devices	13,075,532	317,755	25,296			13,367,991
68	(368) Line Transformers	164,654,798	7,383,986	1,959,698			170,079,086
69	(369) Services	76,585,841	2,950,175	375,321			79,160,695
70	(370) Meters	25,537,484	353,999	269,625			25,621,858
71	(371) Installations on Customer Premises	20,317,894	2,859,433	2,451,960			20,725,367
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	5,363,552	605,519	314,620			5,654,451
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,118,501,533	84,660,882	9,421,452			1,193,740,963
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	2,042,937	91,754				2,134,691
87	(390) Structures and Improvements	27,976,747	1,480,294	718,733			28,738,308
88	(391) Office Furniture and Equipment	3,445,780	364,725				3,810,505
89	(392) Transportation Equipment	23,585,710	482,795				24,068,505
90	(393) Stores Equipment	304,824	152,146	27,200			429,770
91	(394) Tools, Shop and Garage Equipment	7,697,680	413,402	2,744			8,108,338
92	(395) Laboratory Equipment	225,704					225,704

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
93	(396) Power Operated Equipment	2,221,244					2,221,244
94	(397) Communication Equipment	44,234,259	2,649,023	54,040			46,829,242
95	(398) Miscellaneous Equipment	2,469,745		272,497			2,197,248
96	SUBTOTAL (Enter Total of lines 86 thru 95)	114,204,630	5,634,139	1,075,214			118,763,555
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)	114,363,449	5,634,139	1,075,214			118,922,374
100	TOTAL (Accounts 101 and 106)	3,371,614,967	275,083,477	36,020,515			3,610,677,929
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)	3,371,614,967	275,083,477	36,020,515			3,610,677,929

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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					

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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	12/31/2025	556,145.00
3	Items under $250,000			245,526
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
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47	TOTAL			801,671

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	ADMS Imp DSN DNEX-KYP D	2,437,890
2	Bellefonte KY-T Supp	1,064,258
3	CIS-Common Deployment-KYP D	1,806,922
4	Corp Prgrm Billing-KYPCO Trans	1,136,500
5	D/KP/Capital Blanket - KYPCo	1,320,203
6	Ed-Ci-Kepco-D Ast Imp	5,348,030
7	Hatfield KPCO-T	1,297,727
8	KPCo - D Work	7,802,497
9	KPCo D Work	7,524,131
10	KPCo T Work 1	25,457,751
11	KPCo T Work 2	2,445,461
12	KY D Work	3,343,367
13	KY Next Generation Radio Sys	2,265,605
14	KY T Work	7,954,454
15	KYPCo Distr Pre Eng Parent	2,679,529
16	KyPCo-D Service Restoration Bl	3,911,690
17	ML U2 Cooling Tower Reinforce	1,802,156
18	Prestonsburg-Thelma KPCO-T	1,948,281
19	T/KP/Capital Blanket - KYPCo	3,862,180
20	T/KP/Wooten-Pineville-KP Work	8,470,377
21	WS-CI-KEPCo-G PPB	4,297,553
22	Other Minor Projects Which is under 5% or $1,000,000	19,408,766
43	Total	117,585,328

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	1,267,510,892	1,267,510,892		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	102,688,187	102,688,187		
4	(403.1) Depreciation Expense for Asset Retirement Costs	1,209,506	1,209,506		
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):	3,436,912	[a]3,436,912		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	107,334,605	107,334,605		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(26,830,208)	(26,830,208)		
13	Cost of Removal	(12,732,365)	[b](12,732,365)		
14	Salvage (Credit)	1,021,477	[c]1,021,477		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(38,541,096)	(38,541,096)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	(21,222)	[d](21,222)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,336,283,179	1,336,283,179		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	628,328,600	628,328,600		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	300,277,761	300,277,761		
26	Distribution	373,751,180	373,751,180		
27	Regional Transmission and Market Operation				
28	General	33,925,638	33,925,638		
29	TOTAL (Enter Total of lines 20 thru 28)	1,336,283,179	1,336,283,179		

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FOOTNOTE DATA

(a) Concept: OtherAccounts

Environmental costs recovered per KPSC Order Case No. 2014-00396	3,418,129
ARO accretion and depreciation expense	(20,036)
Defer ARO Deprec & Accretion Exp	38,819
Total	3,436,912

(b) Concept: CostOfRemovalOfPlant

Includes $1,304,516 of removal cost in retirement work in progress (RWIP).

(c) Concept: SalvageValueOfRetiredPlant

Includes ($435,726) of salvage in retirement work in progress (RWIP).

(d) Concept: OtherAdjustmentsToAccumulatedDepreciation

Defer ARO Deprec&Accretion Exp	$(43,859)
ARO Removal Deprec - Accretion	$22,637
TOTAL	$(21,222)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
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29								
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								
41								

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)
42	Total Cost of Account 123.1 $		Total					
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MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	78,362,191	57,068,481	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	2,275,502	2,421,988	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	12,422,278	13,556,414	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	12,419,783	9,971,316	Electric
8	Transmission Plant (Estimated)	45,182	10,431	Electric
9	Distribution Plant (Estimated)	288,376	349,096	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[(a)]79,637	[(b)]86,528	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	25,255,256	23,973,785	
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	105,892,949	83,464,254	

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther
Assigned to - Other includes customer account, administrative and general expenses.
(b) Concept: PlantMaterialsAndOperatingSuppliesOther
Assigned to - Other includes Customer Account, Administrative and General Expenses.

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Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year’s allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA’s sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA’s sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	313,079	8,472,258	54,080		54,079		54,080		1,379,709		1,855,027	8,472,258
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)			5,263						44,351		49,614	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	1,886	38,368									1,886	38,368
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	311,193	8,433,890	20,177		54,079		54,080		1,424,060		1,863,589	8,433,890
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains		15										15
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	362		362		362		362		24,244		25,692	
37	Add: Withheld by EPA									723		723	
38	Deduct: Returned by EPA												
39	Cost of Sales	362								361		723	

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
40	Balance-End of Year			362		362		362		24,606		25,692	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												
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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	60,367	82,000									60,367	82,000
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	361		4,714								5,075	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9	Monongahela Power	110	157,143									110	157,143
10													
11													
12													
13													
14													
15	Total	110	157,143									110	157,143
16													
17	Relinquished During Year:												
18	Charges to Account 509	2,710	42,857									2,710	42,857
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Monongahela Power	200	114,286									200	114,286
23													
24													
25													
26													
27													
28	Total	200	114,286									200	114,286
29	Balance-End of Year	57,928	82,000	4,714								62,642	82,000
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)		180,714										180,714
34	Gains		180,714										180,714
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	AF1-130	7,643	186	258	186
3	AF1-162	2,174	186	2,174	186
4	AF2-018	2,830	186	3,457	186
5	AG1-066	21,878	186	21,878	186
6	AH1-644	(822)	186		
7	AI2-342	(155)	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 Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	2020 KY Storm Deferral	10,509,844				10,509,844
2	2021 KY Storm Deferral	45,996,003				45,996,003
3	2021 PJM Annual Transmission Requirement	4	56,215	242, 256	4	56,215
4	2022 KY Major Storm Deferral	13,838,283		0		13,838,283
5	Big Sandy Recovery Over/Under, Kentucky PSC Case No. 2014-00396	(60,247,837)	2,732,263	407	3,104,003	(60,619,577)
6	Big Sandy Retirement Rider Unit 2 O&M, Kentucky PSC Case No. 2014-00396	938,401	10,495			948,896
7	BS1OR Under Recovery, Kentucky PSC Case No. 2014-00396		559,581	182, 407	559,581	
8	CCS FEED Study Costs, Kentucky PSC Case No. 2014-00396	576,086		506	34,914	541,172
9	Cost of Removal-Big Sandy Coal, Kentucky PSC Case No. 2014-00396	(25,047,333)	15,006	108	60,000	(25,092,327)
10	Deferred Depreciation - Environmental, Kentucky PSC Case No. 2014-00396	1,729,675	6,765,023	403	3,346,895	5,147,803
11	Depreciation Expense - Hanging Rock/Jefferson 765 KV Line, Amortization Period: 12/1984 - 11/2032	46,441		182, 406	5,208	41,233
12	Demand Side Management Programs		399,463	254, 456, 908	375,437	24,026
13	IGCC Pre-Construction Costs, Kentucky PSC Case No. 2014-00396, Amortization Period: 07/2015 - 06/2040	878,628		506	53,250	825,378
14	KY ELG Deferral	241,166		506	241,166	
15	KY Steam Maint O/U	8,110		512	8,110	
16	KY Under-Recovered PPA Rider	61,375,622	3,064,099	566	7,067,111	57,372,610
17	M&S - Retiring Plants, Kentucky PSC Case No. 2014-00396	3,015,785				3,015,785
18	NBV - AROs Retired Plants, Kentucky PSC Case No. 2014-00396	5,200,640	47,331,282	182	237,538	52,294,384
19	NERC Compliance and Cybersecurity Costs, Kentucky PSC Case No. 2014-00396	2,733,791	1,102,212	182, 431, 404	630,913	3,205,090
20	Unrealized Loss on Forward Commitments Regulated Assets/Liabilities	10,037,792	73,968	175, 244, 254, 256, 456	10,103,883	7,877
21	OSS Margin Sharing, Kentucky PSC Case No. 2017-00179	5,271,782	474,671	561	3,879,211	1,867,242
22	PJM Greenhat Default Deferral	3,535	5,639,218	561, 0	3,535	5,639,218
23	Post In-Service AFUDC Hanging Rock/Jefferson 765 KV Line, Amortization Period: 12/1984 - 11/2032	298,152		182, 406	33,408	264,744
24	Rate Cases Expenses	1,011,972		928	371,311	640,661
25	Rockport Capacity Deferral, Kentucky PSC Case No. 2017-00179	43,511,762	7,434,543	182, 431, 555	5,935,587	45,010,718
26	SFAS 106 Medicare Subsidy, Amortization Period: 12/2013 - 12/2024	216,619		926	216,619	
27	SFAS 109 Deferred FIT	47,550,347	23,350,619	190, 236, 254, 282, 283, 409, 410, 411	25,990,710	44,910,256
28	SFAS 109 Deferred SIT	98,023,055	5,952,287	283	2,828,705	101,146,637
29	SFAS 112 Post Employment Benefit	3,268,874	374,762	228, 242	1,212,665	2,430,971
30	SFAS 158 Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans	24,570,405	42,474,066	129, 228	53,318,422	13,726,049
31	Spent AROs - Big Sandy Coal, Kentucky PSC Case No. 2014-00396	110,280,370	230,151	—		110,510,521
32	Unrecovered Fuel Cost	10,687,804	12,313,761	501	14,366,985	8,634,580
33	Unrecovered Plant - Big Sandy, Kentucky PSC Case No. 2014-00396	256,509,062				256,509,062
34	2023 PJM Annual Transmission Requirement	348,406	529,012	447	394,826	482,592

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
35	2023 Kentucky Storm Deferral	8,415,089	4,099,303	146, 182, 234, 571, 573	4,099,303	8,415,089
36	KY Deferred Securitization Exp	592,623	1,674,499		0	2,267,123
37	Deferred NOLC Equity Carrying Charges			182	4,360,996	(4,360,996)
38	BSDR Deferred Carrying Charges		17,244,859			17,244,859
39	BSDR Deferred Equity Carrying Charges			182, 431	7,135,402	(7,135,402)
40	Deferred NOLC Carrying Charges		4,360,996			4,360,996
41	2024 PJM Annual Transmission Requirement		101,279	447	30,423	70,856
42	2024 Kentucky Storm Deferral		10,783,447			10,783,447
44	TOTAL	682,390,958	199,147,081		150,006,121	731,531,918

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MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Deferred Property Tax	26,912,919	19,616,733	107/236/408	25,613,018	20,916,634
2	Agency Fees - Factored A/R	661,246	13,414,856	142/184/426	13,005,251	1,070,851
3	Unamortized Credit Line Fees, Amortized thru March 2027	276,856	360,828	431	134,880	502,804
4	Miscellaneous Items	(64,087)	57,234			(6,853)
5	Trnsrce OU Acctg for Def Asset	17,243	37,541	253	25,086	29,698
6	PJM Transmission True-up	12,253,072	15,003,337	186/253/456/565	18,763,128	8,493,281
7	Deferred Expenses - Current		184			184
47	Miscellaneous Work in Progress	365,761				110,270
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	40,423,010				31,116,869

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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	EXCESS ADFIT 282 - PROTECTED.	30,889,970	6,268,043
3	NOL-STATE C/F-DEF TAX ASSET-L/T	15,625,910	(2,769,455)
4	ACCRD BOOK ARO EXPENSE - SFAS 143	3,635,783	16,474,882
5	INT EXP CAPITALIZED FOR TAX	7,010,986	17,671,086
6	REG ASSET-UNRECOVERED PLANT-BIG SANDY	2,838,980	(4,873,718)
7	Other	(36,505,726)	(563,751)
8	TOTAL Electric (Enter Total of lines 2 thru 7)	23,495,903	32,207,087
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	[a]51,471,128	49,926,129
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	74,967,031	82,133,216

Notes

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Line 17 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Acc Def Income Taxes - Federal - Hdg-CF-Int Rate	-	-
Non Utility Items - 190.2	-	-
SFAS 109-Regulatory Assets - 190.3, 190.4 & 190.6	51,471,128	49,926,129
SFAS 133	-	-
Accu Def Income Taxes Pension-OCI	-	-
Total	51,471,128	49,926,129

Line 18
Reconciliation of details applicable to Account 190, Line 18, Columns (b) and (c) :

Balance at Beginning of Year	74,967,031
(Less) Amounts Debited to:	
(a) Account 410.1	(14,047,577)
(b) Account 410.2	-
(c) 1823/254/219/129/427	7,494,894
(Plus) Amounts Credited to:	
(a) Account 411.1	32,394,039
(b) Account 411.2	-
(c) 1823/254/219/129/427	(18,675,171)
Balance at End of Year	82,133,216

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2		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									

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-04-08	Year/Period of Report End of: 2024/ Q4

Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

   a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
   b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
   c. Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
   d. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	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	3,447,230
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	(701,806)
16	Ending Balance Amount	2,745,424
17	**Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	526,069,518

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a)principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2													
3													
4													
5	Subtotal												
6	Reacquired Bonds (Account 222)												
7													
8													
9													
10	Subtotal												
11	Advances from Associated Companies (Account 223)												
12	Notes Payable to Parent -AEP Company ,Inc Interest Rate: 5.29%		25,000,000					06/13/2023	06/13/2028	06/13/2023	06/13/2028		841,257
13	Subtotal		25,000,000										841,257
14	Other Long Term Debt (Account 224)												
15	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
16	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
17	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
18	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
19	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
20	[a] 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

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)
21	Senior Unsecured Notes - 3.13%, Series F		65,000,000					09/12/2017	09/12/2024	09/12/2017	09/12/2024		1,418,499
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
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	[(b)] 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		
27								06/30/2024	06/30/2025	06/30/2024	06/30/2025	150,000,000	9,496,384
27	Subtotal		1,280,000,000		3,081,116		671,250					1,215,000,000	69,504,133
33	TOTAL		1,305,000,000									1,215,000,000	[(c)] 70,345,390

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription
The $25M 5.29% Notes Payable to Parent -AEP Company ,Inc were retired early on 8/20/2024 before the maturity date 6/13/2028
(b) Concept: ClassAndSeriesOfObligationCouponRateDescription
The $65M 3.13% Senior Unsecured Notes Series F were matured on 9/12/2024
(c) Concept: InterestExpenseOnLongTermDebtIssued
The difference between the total interest on this schedule and the total of accounts 427 and 430 is due to interest on short-term advances from the AEP Money Pool.

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	36,861,721
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	[a](9,161,127)
28	Show Computation of Tax:	
29		
30		
31		
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43		
44		

FOOTNOTE DATA

(a) Concept: FederalTaxNetIncome

FOOTNOTE DATA

Schedule Page: 261 Line No.: 28 Column: b	in $ 000's
Net Income for the Year per Page 117	36,862
Federal Income Taxes	4,016
State Income Taxes	(1,035)
	—
Pre-Tax Book Income`	39,843
Excess Tax vs Book Depreciation	3,865
AFUDC and Other Capitalization Differences	(810)
Book Unit of Property Adjustment	(41,633)
Removal Cost	(12,164)
Pollution Control Equipment	7,711
Property Tax	—
Provision for Revenue Refunds	508
Deferred Fuel	2,053
Book Accruals	(577)
Book Deferrals	2,837
Other Miscellaneous	(10,528)
Non Deduct expenses	233
Capitalized Software - Tax	2
Capitalized Software - Book	—
Mark-to-Market	—
Emission Allowances	38
Others	—

FOOTNOTE DATA

Taxable Income before State Taxes	(8,622)
Deductions for Fed/Other States	539
State & Local Current Tax	—
Federal Taxable Income	(9,161)
FIT on Current Year Taxable Income (21%)	(1,924)
NOL Reclass	—
Tax Credit CFWD	11
ALT Min Tax	
ETR Adjustment	
R&D Credit - Current	32
Estimated Tax Currently Payable (b)	43
Current Tax (a) - (b)	(1,967)
Adjustments of Prior Year's Accruals	3,817
Tax Expense for R/C of Net Operating Loss (Prior Yr)	
Estimated Current Federal Income Taxes	1,850

Foot Notes:
(a) Represents the allocation of the estimated current year net operating tax loss of American Electric Power Company, Inc.
(b) The Company joins in the filing of a consolidated Federal income tax return with its affiliated companies in the AEP system. The allocation of the AEP System's consolidated Federal income tax to the System companies allocates the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, American Electric Power Company, Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidating group.
INSTRUCTION 2.
* The tax computation above represents an estimate of the Company's allocated portion of the System consolidated Federal income tax. The computation of actual 2024 System. Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by October 2025. The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until after the consolidated federal income tax return is filed

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR	
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)
1	Pers Prop Leased	Property Tax	KY		938,315.00	0.00	61,055.00	47,017.00		952,353.00	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		42,178,162.00	0.00	9,247,670.00	17,000,266.00		34,425,566.00	0.00
4	Real & Pers Prop	Property Tax	MI		0.00	0.00	0.00	0.00		0.00	0.00
5	Real & Pers Prop	Property Tax	WV		4,326,443.00	0.00	3,123,634.00	2,867,073.00		4,583,004.00	0.00
6	Real Prop Leased	Property Tax	KY		10,629.00	0.00	21,491.00	32,120.00		0.00	0.00
7	Unemployment Tax	Unemployment Tax	KY		2,141.00	0.00	10,017.00	9,992.00		2,166.00	0.00
8	Unemployment Tax	Unemployment Tax	OH		0.00	0.00	27.00	0.00		27.00	0.00
9	Unemployment Tax	Unemployment Tax	WV		2.00	0.00	1,746.00	1,450.00		298.00	0.00
10	Unemployment Tax	Unemployment Tax	(blank)		3,748.00	0.00	13,718.00	12,920.00		4,546.00	0.00
11	Sales Tax	Sales And Use Tax	KY		0.00	311,523.00	0.00	15,761.00		0.00	327,284.00
12	Use Tax	Sales And Use Tax	KY		(533,551.00)	49,105.00	2,828,453.00	2,206,374.00		109,763.00	70,340.00
13	Use Tax	Sales And Use Tax	WV		2,876.00	0.00	54,753.00	56,008.00		1,621.00	0.00
14	City Tax	Income Tax			(49,346.00)	0.00	0.00	0.00		(49,346.00)	0.00
15	Federal Income	Income Tax			841,088.00	0.00	2,551,433.00	1,201,612.00		2,190,909.00	0.00
16	State Income Tax	Income Tax	IL		7,011.00	0.00	10,312.00	0.00		17,323.00	0.00
17	State Income Tax	Income Tax	KY		(232,374.00)	0.00	(225,947.00)	272,000.00		(730,321.00)	0.00
18	State Income Tax	Income Tax	MI		0.00	0.00	0.00	0.00		0.00	0.00
19	State Income Tax	Income Tax	MULTI		(360,769.00)	0.00	0.00	0.00		(360,769.00)	0.00
20	State Income Tax	Income Tax	WV		827,933.00	0.00	483,740.00	0.00		1,311,673.00	0.00
21	State Income Tax	Income Tax	CA		0.00	0.00	0.00	0.00		0.00	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	14,640.00	14,640.00		0.00	0.00
24	Federal Insurance Tax	Federal Insurance Tax	(blank)		170,435.00	0.00	2,637,584.00	2,640,205.00		167,814.00	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	19.00	19.00		0.00	0.00
27	Utility Gr Lic - EDP	Other State Tax	KY		1,710.00	0.00	19,792.00	19,853.00		1,649.00	0.00
28	WV Business & Occupation	Other Property Tax	WV		535,646.00	0.00	7,350,043.00	7,271,552.00		614,137.00	0.00
29	Muni License Fee	Other Taxes and Fees	KY		0.00	0.00	0.00	25.00		(25.00)	0.00
30	Muni License Fee	Other Taxes and Fees	WV		0.00	0.00	0.00	20.00		(20.00)	0.00
40	TOTAL				48,910,684.00	360,628.00	28,204,180.00	33,668,907.00		43,482,953.00	397,624.00

Line No.	DISTRIBUTION OF TAXES CHARGED			
	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1	61,055.00			0.00
2	2,487.00			(2,487.00)
3	13,691,876.00			(4,444,206.00)
4	(10.00)			10.00
5	3,138,351.00			(14,717.00)
6	21,491.00			0.00
7	2,952.00			7,065.00
8	8.00			19.00
9	15,275.00			(13,529.00)
10	10,603.00			3,116.00
11	0.00			0.00
12	54,008.00			2,774,445.00
13	20.00			54,733.00
14	0.00			0.00
15	2,128,544.00			422,889.00
16	10,312.00			0.00
17	(157,246.00)			(68,701.00)
18	0.00			0.00
19	0.00			0.00
20	485,138.00			(1,398.00)
21	0.00			0.00
22	0.00			0.00
23	14,640.00			0.00
24	1,981,095.00			656,489.00
25	0.00			0.00
26	19.00			0.00
27	19,792.00			0.00
28	7,350,043.00			0.00
29	0.00			0.00
30	0.00			0.00
40	28,830,453.00			(626,272.00)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%									
4	7%									
5	10%		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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	TV Pole Attachments	155,419	186/454	907,857	887,726	135,288
2	Customer Advance Receipts	5,996,300	142	5,996,300	2,486,968	2,486,968
3	Deferred Gain: Fiber Optic Agrmts-In Kind SvcAmortize through June 2026	40,407	124/411	14,517		25,890
4	Deferred Revenue Fiber Optic Lines-Sold-Defd Rev Amortize through January 2025	963	451	889		74
5	PJM Transmission True-up	4,107,577	449/229/186/565	5,464,313	9,547,940	8,191,204
6	Miscellaneous	1,374	142/186	20,387,283	20,385,909	
7	Contribution Aid of Construction	170,931	107/108	170,931	447,138	447,138
8	Deferred Credits	58,439	142/143	58,439	63,453	63,453
9	Legal Contingencies		921	3,184	2,513	(671)
10	Deferred Rev-Bonus Lease	5,691	421	5,691		
11	NERC Penalties	84,615	426	11,745		72,870
47	TOTAL	10,621,717		33,021,149	33,821,647	11,422,215

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities	41,222,314	61,179	2,142,329				406			39,140,758
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	41,222,314	61,179	2,142,329				406			39,140,758
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	[a] OTHER	(16,015,430)					254	10,870	254	523,422	(15,502,878)
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	25,206,884	61,179	2,142,329				11,276		523,422	23,637,880
18	Classification of TOTAL										
19	Federal Income Tax	25,206,884	61,179	2,142,329				10,870		523,016	23,637,880
20	State Income Tax										
21	Local Income Tax										

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfAcceleratedAmortizationPropertyOtherUtilityOther

232,561,566

Description Page 272-273 Line 16	Balance at Beginning of The year	Debit Adjust.	Credit Adjust.	Balance End of Year
SFAS 109	(16,015,430)	(10,870)	523,422	(15,502,878)
Total Line 16	(16,015,430)	(10,870)	523,016	(15,502,878)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	323,888,291	23,281,261	15,800,124				7,563,277	—		323,806,151
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	323,888,291	23,281,261	15,800,124				7,563,277			323,806,151
6	Others	[a](39,653,054)					1823/254	4,633,856	1823/254	8,032,444	(36,254,466)
9	TOTAL Account 282 (Total of Lines 5 thru 8)	284,235,237	23,281,261	15,800,124				12,197,133		8,032,444	287,551,685
10	Classification of TOTAL										
11	Federal Income Tax	284,235,237	23,281,261	15,800,124				12,197,133		8,032,444	287,551,685
12	State Income Tax										
13	Local Income Tax										

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Line 6 Footnote

	Beg Bal	Debits	Credits	End Bal
Non-Utility	0	0	0	0
SFAS 109	(39,653,054)	4,633,856	8,032,444	(36,254,466)
Total Other - Line 6	(39,653,054)	0	8,032,444	(36,254,466)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	Deferred Fuel Costs	2,244,438	2,545,391	2,976,568							1,813,261
4	Reg Asset - Big Sandy Retirement	61,036,308	394,917	431,895							60,999,330
5	Reg Asset - Rockport Capacity Deferral	6,425,178	630,536	662,599							6,393,115
6	Reg Asset - KY Storms	16,539,436	860,854	860,854							16,539,436
7	Reg Asset - PPA Rider	12,888,881	643,461	1,484,093							12,048,249
8	Other	11,656,567	27,101,651	11,950,895				2,429,407			24,377,916
9	TOTAL Electric (Total of lines 3 thru 8)	110,790,808	32,176,810	18,366,904				2,429,407			122,171,307
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	[(a)] 128,577,471					1823/254	20,611,597	1823/254	24,823,745	132,789,619
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	239,368,279	32,176,810	18,366,904				23,041,004		24,823,745	254,960,926
20	Classification of TOTAL										
21	Federal Income Tax	139,648,560	32,176,810	17,914,192				7,227,312		5,886,471	152,570,337
22	State Income Tax	99,719,719		452,712				15,813,692		18,937,274	102,390,589
23	Local Income Tax										

NOTES

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Line 18 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Non-Utility	—	—
SFAS 109	125,976,148	132,789,619
Provision	2,601,323	0
Total	$ 128,577,471	$ 132,789,619

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Capacity Charge Tariff OverRec	488,175	—	122,044		366,131
2	Home Energy Assistance Program	296,414	182, 440, 442, 444	1,065,547	1,959,986	1,190,853
3	Kentucky Reliability	464,967	593	3,390,523	3,561,562	636,006
4	KY - DSM Over Recovery	18,122	182	88,283	70,161	
5	PJM Trans Enhancement Reg Liability	1,390,680	142	639,454	(1)	751,225
6	SFAS 109 Deferred FIT	123,777,727	190, 282, 283	9,637,827	810,843	114,950,743
7	Steam Maintenance Levelized Reg Liability, KY Case No. 2017-00179	2,097,760	512	671,058		1,426,702
8	Unrealized Gain on Forward Commitments		182	1,605,053	2,449,450	844,397
41	TOTAL	128,533,845		17,219,789	8,852,001	120,166,057

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Electric Operating Revenues

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	279,997,957	249,070,905	1,858,160	1,755,606	130,852	131,090
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	190,932,900	161,706,008	1,438,141	1,343,396	30,391	30,341
5	Large (or Ind.) (See Instr. 4)	167,644,587	152,755,090	2,016,139	2,059,998	958	1,001
6	(444) Public Street and Highway Lighting	2,140,814	1,994,130	8,838	9,346	306	311
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	[a]640,716,258	[c]565,526,133	5,321,277	5,168,345	162,506	162,743
11	(447) Sales for Resale	23,862,331	20,926,029	465,216	518,228	5	4
12	TOTAL Sales of Electricity	664,578,589	586,452,162	5,786,493	5,686,573	162,511	162,747
13	(Less) (449.1) Provision for Rate Refunds	6,446,586	2,036,085				
14	TOTAL Revenues Before Prov. for Refunds	658,132,003	584,416,077	5,786,493	5,686,573	162,511	162,747
15	Other Operating Revenues						
16	(450) Forfeited Discounts	866,468	1,412,867				
17	(451) Miscellaneous Service Revenues	123,252	131,760				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	9,447,705	8,690,173				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[b]1,047,884	811,473				
22	(456.1) Revenues from Transmission of Electricity of Others	36,965,056	27,259,513				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	48,450,365	38,305,786				
27	TOTAL Electric Operating Revenues	706,582,368	622,721,863				

Line12, column (b) includes $ 5,463,537 of unbilled revenues.
Line12, column (d) includes 12,055 MWH relating to unbilled revenues

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) 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

(b) Concept: OtherElectricRevenue

Description	2024 YTD	2023 YTD
Oth Elect Rev - Demand Side Management Program	416,239	450,918
Other Electric Revenues - ABD	631,645	349,355
All Other (Under $250,000)		11,200
	1,047,884	**811,473**

(c) Concept: SalesToUltimateConsumers

Detail of Unmetered Sales - 2023

	Revenue	MWH	Average No. of Customers
Residential	5,566,419	21,210	38,778
Commercial	2,967,617	13,752	7,086
Industrial	134,751	681	193
Public Street Lighting	35,726	105	39
Total	8,704,513	35,748	46,096

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
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39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Estimated					
2	General Service R	100	17,739	10	10,000	0.1774
3	Outdoor Lighting R	19,508	5,871,038			0.3010
4	Residential Load Management-Time-of-Day R	2,634	371,651	141	18,681	0.1411
5	Residential Service R	1,830,075	269,111,585	130,694	14,003	0.1470
6	Residential Service Time-of-Day R	168	23,704	7	24,000	0.1411
7	Unrecovered R					
8	Kentucky Rider R		(1,127,501)			
9	Revenue related to the Rockport Offset True-up Case 2024-00016)		2,425,982			
41	TOTAL Billed Residential Sales	1,852,485	276,694,198	130,852	14,157	0.1494
42	TOTAL Unbilled Rev. (See Instr. 6)	5,675	3,303,759			0.5822
43	TOTAL	1,858,160	279,997,957	130,852	14,200	0.1507

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Unrecovered C					
2	Kentucky Rider C		(920,473)			
3	Estimated C	3,758	879,839			
4	Revenue related to the Rockport Offset True-up Case 2024-00016)		1,708,157			
5	General Service C	588,296	100,331,095	29,880	19,689	0.1705
6	Industrial General Service C	435,173	29,414,812	25	17,406,920	0.0676
7	Large General Service C	385,209	53,596,472	471	817,854	0.1391
8	Large General Service Time-of-Day C	6,020	764,879	7	860,000	0.1271
9	Municipal WaterworksC	1,862	250,939	8	232,750	0.1348
10	Outdoor Lighting C	13,068	3,223,094			0.2466
11	Residential Service C					
41	TOTAL Billed Small or Commercial	1,433,386	189,248,814	30,391	47,165	0.1320
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	4,755	1,684,086			0.3542
43	TOTAL Small or Commercial	1,438,141	190,932,900	30,391	47,321	0.1328

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Contract Service – Interruptible Power I	188,277	13,267,950	5	37,655,400	0.0705
2	Estimated I	91,093	7,769,740			0.0853
3	General Service I	21,122	3,569,433	830	25,448	0.1690
4	Industrial General Service I	1,627,943	129,663,028	32	50,873,219	0.0796
5	Large General Service I	82,295	13,028,829	89	924,663	0.1583
6	Large General Service Time-of-Day I	3,151	376,629	2	1,575,500	0.1195
7	Outdoor Lighting I	627	139,228			0.2221
8	Unrecovered I					
9	Kentucky Rider I		(1,350,645)			
41	TOTAL Billed Large (or Ind.) Sales	2,014,508	167,170,071	958	2,102,827	0.0830
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	1,631	474,516			0.2909
43	TOTAL Large (or Ind.)	2,016,139	167,644,587	958	2,104,529	0.0832

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Estimated					
2	General Service	744	203,184	253	2,941	0.2731
3	Outdoor Lighting	104	42,593			0.4095
4	Street Lighting	7,996	1,899,781	53	150,868	0.2376
5	Unrecovered					
6	Kentucky Rider		(5,920)			
41	TOTAL Billed Public Street and Highway Lighting	8,844	2,139,638	306	28,902	0.2419
42	TOTAL Unbilled Rev. (See Instr. 6)	(6)	1,176			(0.1960)
43	TOTAL	8,838	2,140,814	306	28,882	0.2422

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
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27						
28						
29						
30						
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		6,446,586			

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	5,309,223	635,252,721	162,507	2,193,051	
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	12,055	5,463,537			
43	TOTAL - All Accounts	5,321,278	640,716,258	162,507	2,193,051	

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

   SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

   LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

   OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		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				20,952	533,941	1,710,836		2,244,777
2	CITY OF VANCEBURG	RQ	KPCO 51				53,472	1,294,489	3,648,102		4,942,591
3	PJM INTERCONNECTION	OS	NOTE 1				390,792	(72,041)	19,320,362		19,248,321
4	PJM INTERCONNECTION	RQ	NOTE 1				0			(2,566,487)	(2,566,487)
5	RBC CAPITAL MARKET, LLC	OS	NOTE 1				0		(399)		(399)
6	WELLS FARGO SECURITIES, LLC	OS	NOTE 1				0		(6,472)		(6,472)
15	Subtotal - RQ						74,424	1,828,430	5,358,938	(2,566,487)	4,620,881
16	Subtotal-Non-RQ						390,792	(72,041)	19,313,491		19,241,450
17	Total						465,216	1,756,389	24,672,429	(2,566,487)	23,862,331

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	4,426,925	5,403,024
5	(501) Fuel	135,378,424	114,274,670
6	(502) Steam Expenses	5,053,243	5,480,809
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	44,420	33,158
10	(506) Miscellaneous Steam Power Expenses	6,265,855	5,758,190
11	(507) Rents		
12	(509) Allowances	81,225	26,724
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	151,250,092	130,976,575
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,677,430	1,620,359
16	(511) Maintenance of Structures	1,794,464	1,932,042
17	(512) Maintenance of Boiler Plant	13,481,479	12,368,273
18	(513) Maintenance of Electric Plant	3,949,152	3,879,179
19	(514) Maintenance of Miscellaneous Steam Plant	1,535,471	1,688,834
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	22,437,996	21,488,687
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	173,688,088	152,465,262
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		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
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		
64.1	(548.1) Operation of Energy Storage Equipment		
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 Energy Storage 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	107,599,231	118,405,459
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	69,875	50,367
78	(557) Other Expenses	799,007	766,317
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	108,468,113	119,222,143
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	282,156,201	271,687,405
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,064,772	2,871,391
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	386,085	324,596
87	(561.3) Load Dispatch-Transmission Service and Scheduling	130	
88	(561.4) Scheduling, System Control and Dispatch Services	1,396,897	1,368,435
89	(561.5) Reliability, Planning and Standards Development	78,081	69,826
90	(561.6) Transmission Service Studies		(1)
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	452,211	369,553
93	(562) Station Expenses	203,497	260,205
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	27,183	22,203
95	(564) Underground Lines Expenses	16	12,130
96	(565) Transmission of Electricity by Others	78,574,635	68,473,837
97	(566) Miscellaneous Transmission Expenses	2,447,476	(22,553,468)
98	(567) Rents		
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	85,630,983	51,218,707
100	Maintenance		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
101	(568) Maintenance Supervision and Engineering	22,224	2,604
102	(569) Maintenance of Structures	32,286	7,201
103	(569.1) Maintenance of Computer Hardware	7,901	9,712
104	(569.2) Maintenance of Computer Software	223,926	192,357
105	(569.3) Maintenance of Communication Equipment	7,739	6,442
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	461,398	994,975
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	5,005,477	5,486,423
109	(572) Maintenance of Underground Lines	316	662
110	(573) Maintenance of Miscellaneous Transmission Plant	2,918	1,608
111	TOTAL Maintenance (Total of Lines 101 thru 110)	5,764,185	6,701,984
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	91,395,168	57,920,691
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	1,442,994	1,049,964
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,442,994	1,049,964
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)	1,442,994	1,049,964
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,192,931	873,874
135	(581) Load Dispatching	1,048	1,968
136	(582) Station Expenses	387,429	325,489
137	(583) Overhead Line Expenses	281,948	469,217
138	(584) Underground Line Expenses	326,743	260,153
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	40,246	59,168
140	(586) Meter Expenses	1,353,435	1,211,647
141	(587) Customer Installations Expenses	191,956	222,454
142	(588) Miscellaneous Expenses	6,285,823	3,337,241
143	(589) Rents	1,048,358	796,344
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	11,109,917	7,557,555
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	15,594	18,724
147	(591) Maintenance of Structures	10,318	3,288
148	(592) Maintenance of Station Equipment	888,071	784,295
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	31,281,486	32,117,233
150	(594) Maintenance of Underground Lines	24,176	24,053
151	(595) Maintenance of Line Transformers	16,734	33,838
152	(596) Maintenance of Street Lighting and Signal Systems	9,850	24,697

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
153	(597) Maintenance of Meters	37,643	34,288
154	(598) Maintenance of Miscellaneous Distribution Plant	27,046	20,915
155	TOTAL Maintenance (Total of Lines 146 thru 154)	32,310,918	33,061,331
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	43,420,834	40,618,886
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	13,540	14,777
160	(902) Meter Reading Expenses	346,932	374,993
161	(903) Customer Records and Collection Expenses	4,846,162	4,915,009
162	(904) Uncollectible Accounts	20,263	473,357
163	(905) Miscellaneous Customer Accounts Expenses	19,916	43,766
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	5,246,813	5,821,902
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	51,153	22,327
168	(908) Customer Assistance Expenses	1,687,407	1,510,068
169	(909) Informational and Instructional Expenses		85,427
170	(910) Miscellaneous Customer Service and Informational Expenses	14,382	15,669
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	1,752,942	1,633,491
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	11,031	12,959
176	(913) Advertising Expenses	80	
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	11,111	12,959
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	12,245,270	11,303,490
182	(921) Office Supplies and Expenses	516,549	566,140
183	(Less) (922) Administrative Expenses Transferred-Credit	1,824,875	1,366,972
184	(923) Outside Services Employed	6,729,133	1,233,190
185	(924) Property Insurance	(g) 1,092,472	1,191,497
186	(925) Injuries and Damages	2,264,769	(971,070)
187	(926) Employee Pensions and Benefits	127,663	(3,099,483)
188	(927) Franchise Requirements	162,329	140,462
189	(928) Regulatory Commission Expenses	3,992,821	3,801,736
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	119,861	134,748
192	(930.2) Miscellaneous General Expenses	760,593	480,603
193	(931) Rents	69,999	45,246
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	26,256,584	13,459,587
195	Maintenance		
196	(935) Maintenance of General Plant	3,157,747	2,921,334
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	29,414,331	16,380,921
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	454,840,394	395,126,219

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: PropertyInsurance
The insurance expenses for generation included in KPCo's generation formula rate are identified by a query of the general ledger.

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

   SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

   LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

   EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

   OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

   AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER Demand Charges ($) (k)	COST/SETTLEMENT OF POWER Energy Charges ($) (l)	COST/SETTLEMENT OF POWER Other Charges ($) (m)	COST/SETTLEMENT OF POWER Total (k+l+m) of Settlement ($) (n)
1	PJM INTERCONNECTION	OS					3,020,447				1,945,015	105,654,216		107,599,231
15	TOTAL						3,020,447	0	0	0	1,945,015	105,654,216		107,599,231

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY: Megawatt Hours Received (i)	TRANSFER OF ENERGY: Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS: Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	PJM Network Integ Trans Rev Whlse	Various	Various	FNO	[(a)] PJM OATT	Various	Various				566,742			566,742
2	PJM Network Integ Trans Serv	Various	Various	FNO	PJM OATT	Various	Various				2,382,828			2,382,828
3	PJM Trans Enhancement Rev	Various	Various	FNO	PJM OATT	Various	Various				452,726			452,726
4	PJM Trans Enhancement Rev Whlse	Various	Various	FNO	PJM OATT	Various	Various				12,308			12,308
5	PJM Trans Enhancement Rev - Affil	Various	Various	FNO	PJM OATT	Various	Various				74,407			74,407
6	PJM Network Integ Rev - Affil	Various	Various	FNO	PJM OATT	Various	Various				2,141,469			2,141,469
7	PJM Point to Point Trans Service	Various	Various	LFP	PJM OATT	Various	Various				313,058			313,058
8	PJM Trans Owner Admin Revenue	Various	Various	OLF	PJM OATT	Various	Various					25,686		25,686
9	PJM Trans Owner Serv Rev Whlse	Various	Various	OLF	PJM OATT	Various	Various					1,519		1,519
10	PJM Power Factor Credits Rev Whlse	Various	Various	OS	PJM OATT	Various	Various						[(b)] 963	963
11	PJM Trans Owner Serv - Affil	Various	Various	OLF	PJM OATT	Various	Various					22,203		22,203
12	East Kentucky Power Cooperative	Various	Various	OLF	PJM OATT	Various	Various						[(c)] 10,614	10,614
35	TOTAL							0	0	0	5,943,538	49,408	11,577	6,004,523

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: RateScheduleTariffNumber
Effective October 1, 2004, the administration of the transmission tariff was turned over to PJM. PJM does not provide any detail except for the total revenue by the major classes listed. OATT (Open Access Transmission Tariff) 3rd revised Volume No. 6
(b) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Per Proforma ILDSA (Interconnection and Local Delivery Service Agreement) AEP Tariff 3rd Revised Volume No. 6
(c) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Compensation should be at a rate of one and one-half (1.5) mils per kilowatt-hour for energy delivered pursuant to Appendix IV of PJM Service Agreement No. 1530, the Interconnection Agreement between AEPSC and East Kentucky Power Cooperative.

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
   FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Concurrent Energy	LFP					[(a)]93,290	93,290
2	PJM - Enhancements	OS					7,560,518	7,560,518
3	PJM - Trans Owner	OS					[(b)]166,047	166,047
4	PJM - NITS	OS					[(c)]70,754,780	70,754,780
	TOTAL						[(d)]78,574,635	78,574,635

FOOTNOTE DATA

(a) Concept: OtherChargesTransmissionOfElectricityByOthers
Concurrent Energy Charges from East Kentucky Power.
(b) Concept: OtherChargesTransmissionOfElectricityByOthers
Transmission Enhancement Charges and Credits (PJM OATT Schedule 12)
(c) Concept: OtherChargesTransmissionOfElectricityByOthers
Transmission Owner Charges and Credits (PJM OATT Tariff Sixth Revised Volume No. 1)
(d) Concept: OtherChargesTransmissionOfElectricityByOthers
)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	149,147
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	626
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	Asociated Business Development	378,116
7	AEP Service Corporation Billings	93,835
8	Intercompany Allocations	14,023
9	Corporate Money Pool Allocations	35,491
10	Corporate and Fiscal	88,455
11	Miscellaneous	900
46	TOTAL	760,593

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			9,598,216		9,598,216
2	Steam Production Plant	33,277,642	1,199,649			34,477,291
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	23,913,004				23,913,004
8	Distribution Plant	40,178,892				40,178,892
9	Regional Transmission and Market Operation					
10	General Plant	5,318,649	9,857			5,328,506
11	Common Plant-Electric					
12	TOTAL	102,688,187	1,209,506	9,598,216		113,495,909

B. Basis for Amortization Charges

Section A Line 1 Column D represents amortization of capitalized software development costs over a 5 year life and costs associated with the Oracle strategic partnership which are over a 10 year life.

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	24.579					
14	311 - Mitchell	77.548					
15	312 - Big Sandy	77.874					
16	312 - Mitchell	884.471					
17	312 - Mitchell SCR	9.345					
18	314 - Big Sandy	64.17					
19	314 - Mitchell	56.654					
20	315 - Big Sandy	8.217					
21	315 - Mitchell	26.378					
22	316 - Big Sandy	4.345					
23	316 - Mitchell	9.933					
24	TOTAL COAL/LIGNITE	1,243.514					
25	TRANSMISSION						
26	350.1	35.72					
27	352	26.379					
28	352 - Big Sandy	0.01					
29	352 - Mitchell	0.072					
30	353	283.781					
31	353 - Big Sandy	0.603					
32	353 - Mitchell	12.303					
33	353.16	7.318					
34	354	103.118					
35	355	233.413					
36	356	169.089					
37	356.16	5.15					
38	357	5.173					
39	358	0.106					
40	358.16	0.393					
41	TOTAL TRANSMISSION	882.628					
42	DISTRIBUTION						
43	360.1	6.5					
44	361	14.868					
45	362	153.374					
46	362.16	4.521					
47	364	327.553					
48	365	337.751					
49	366	10.127					
50	367	13.357					
51	368	169.466					
52	369	78.904					
53	370	25.621					
54	371	20.72					
55	373	5.62					
56	TOTAL DISTRIBUTION	1,168.382					
57	GENERAL PLANT						
58	389.1	0.036					
59	390	28.728					
60	391	3.305					
61	391.11	0.495					
62	392	24.069					
63	393	0.43					

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)
64	394	7.928					
65	395	0.226					
66	396	2.221					
67	397	44.852					
68	397.16	1.505					
69	398	2.197					
70	TOTAL GENERAL	115.992					
71	DEPRECIABLE SUM	[a]3,410.516					

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DepreciablePlantBase

The depreciable plant base is the November 30, 2024 total company depreciable plant.

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	2019 Kentucky IRP Plan		305,588	305,588		Electric	928	305,588				
2	Minor Items < $25,000		1,028,288	1,028,288		Electric	928	1,028,288				
3	2020 - Kentucky Power Base Case		310,251	310,251	1,011,972	Electric	928	4,989	(66,049)	928	305,262	640,661
4	KPSC - Case No. 2020-00174											
5	Kentucky PSC Investigation		593,946	593,946		Electric	928	593,946				
6	Kentucky Solar Filing					Electric	928					
7	State Commission Fees					Electric	928					
8	AEPSC KY Power Ebon Case					Electric	928					
9	23 KYP Base Rate Case Filing		577,021	577,021		Electric	928	577,021				
10	24 Big Sandy KY Securitization		326,607	326,607		Electric	928	326,607				
11	Bellefonte Stn Upgrade CPCN		18,168	18,168		Electric	928	18,168				
12	KY Power PLR for NOL ADIT		78,718	78,718		Electric	928	78,718				
13	KY Fuel Adjustment Clause and Cost Recovery		383,582	383,582		Electric	928	383,582				
14	Bright Mountain Solar PPA		61,350	61,350		Electric	928	61,350				
15	KPCo AMI CPCN		135,086	135,086		Electric	928	135,086				
16	Kentucky Power Base Rate Case		78,602	78,602		Electric	928	78,602				
17	KY Power Demand Side Mgmt		65,396	65,396		Electric	928	65,396				
18	RFP for AMI Deployment KYPower		30,218	30,218		Electric	928	30,218				
46	TOTAL		3,992,821	3,992,821	1,011,972			3,687,559	(66,049)		305,262	640,661

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:
   - A. Electric R, D and D Performed Internally:
     1. Generation
        - a. hydroelectric
          - i. Recreation fish and wildlife
          - ii. Other hydroelectric
        - b. Fossil-fuel steam
        - c. Internal combustion or gas turbine
        - d. Nuclear
        - e. Unconventional generation
        - f. Siting and heat rejection
     2. Transmission
        - a. Overhead
        - b. Underground
     3. Distribution
     4. Regional Transmission and Market Operation
     5. Environment (other than equipment)
     6. Other (Classify and include items in excess of $50,000.)
     7. Total Cost Incurred
   - B. Electric, R, D and D Performed Externally:
     1. Research Support to the electrical Research Council or the Electric Power Research Institute
     2. Research Support to Edison Electric Institute
     3. Research Support to Nuclear Power Groups
     4. Research Support to Others (Classify)
     5. Total Cost Incurred
3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	A(1)b: Generation: Fossil-Fuel Steam	Generation Asset Management	3,088		506	3,088	
2		1 items under $50,000	3		506	3	
3	A(1)e: Generation: Unconventional	1 item under $50,000					
4	A(2): Transmission	1 item under $50,000	975		566	975	
5	A(3): Distribution	1 items under $50,000	1,028		588	1,028	
6	A(5): Environment (other than equipment)	1 items under $50,000					
7	A(6): Other	2 items under $50,000	177		506,566,588	177	
8	A(6)a: Alternate Energy	1 item under $50,000					
9	A(6)f: Other (Metering)	1 item under $50,000	582		588	582	
10	A(6)g: Other (program management)	1 item under $50,000	455		566,588	455	
11	B: Electric R&D External	4 items under $50,000		8,052	506,566,588	8,052	
12	B(1): R&D support to the Research Council						
13	or the Electric Power Research	EPRI Research Portfolio		76,040	506,566,588	76,040	
14		EPRI Environmental Science		10,840	506	10,840	
15	Institute	19 items under $50,000		14,851	506,566,588	14,851	
16	B(4): Research Support to Others	1 items under $50,000		59	506	59	

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	8,226,587		
4	Transmission	2,639		
5	Regional Market			
6	Distribution	5,944,368		
7	Customer Accounts	742,446		
8	Customer Service and Informational	287,960		
9	Sales			
10	Administrative and General	1,815,354		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	17,019,354		
12	Maintenance			
13	Production	4,507,003		
14	Transmission	2,222		
15	Regional Market			
16	Distribution	5,536,560		
17	Administrative and General	491,993		
18	TOTAL Maintenance (Total of lines 13 thru 17)	10,537,778		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	12,733,590		
21	Transmission (Enter Total of lines 4 and 14)	4,861		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	11,480,928		
24	Customer Accounts (Transcribe from line 7)	742,446		
25	Customer Service and Informational (Transcribe from line 8)	287,960		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	2,307,347		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	27,557,132	1,429,336	28,986,468
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)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
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)	27,557,132	1,429,336	28,986,468
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	13,902,914	721,118	14,624,032
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	13,902,914	721,118	14,624,032
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,727,350	141,463	2,868,813
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,727,350	141,463	2,868,813
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	938,354	(938,354)	
82	165 - Other Prepayments			
83	182 - Other Regulatory Assets			
84	183 - Prelim Survey	(1,186)	1,186	
85	184 - Clearing Accounts	1,354,749	(1,354,749)	
86	185 - ODD Temporary Facilities	51,600		51,600
87	186 - Misc Deferred Debits	1,071,561		1,071,561
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	23,691		23,691
94	451 - Misc Service Rev - Nonaffil			
95	456 - Other Electric Revenue			
95	TOTAL Other Accounts	3,438,769	(2,291,917)	1,146,852
96	TOTAL SALARIES AND WAGES	47,626,165		47,626,165
	Page 354-355			

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	26,077,574	46,963,569	69,237,021	94,250,848
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(1,443,100)	(6,034,503)	(10,656,609)	(14,192,129)
4	Transmission Rights	(1,869,769)	(3,842,167)	(5,515,471)	(7,800,700)
5	Ancillary Services	(163,232)	(173,071)	(501,189)	(1,035,207)
6	Other Items (list separately)				
7	Congestion	857,865	2,553,957	5,229,267	7,259,930
8	Operating Reserves	405,725	799,734	1,002,614	1,271,201
9	Transmission Purchase Expense	655,786	1,275,734	1,941,993	2,566,481
10	Transmission Losses	1,184,686	1,770,271	2,570,216	3,439,422
11	Meter Corrections	103,435	204,525	(326,867)	(286,900)
12	Inadvertent	5,014	24,324	63,049	60,978
13	Capacity Credits			41,041	72,041
46	TOTAL	25,813,984	43,542,373	63,085,065	85,605,965

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	[a]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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ 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.

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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	[a]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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: MonthlyPeakLoadExcludingIsoAndRto
Kentucky Power Company's transmission service is administered through an RTO/ISO and requested information is not available on an individual operating company basis.

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: 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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-04-08	Year/Period of Report End of: 2024/ Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	5,321,277
3	Steam	3,146,375	23	Requirements Sales for Resale (See instruction 4, page 311.)	74,424
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	390,792
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other		27	Total Energy Losses	380,329
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	3,146,375	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	6,166,822
10	Purchases (other than for Energy Storage)	3,020,447			
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)	6,166,822			

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 0					
29	January	638,245	(30,472)	1,288	17	9
30	February	508,645	39,994	994	19	8
31	March	501,600	47,861	895	11	9
32	April	419,595	(7,337)	769	6	9
33	May	460,503	21,671	806	21	16
34	June	582,101	96,536	923	29	18
35	July	567,316	57,865	965	15	15
36	August	549,855	51,836	980	7	17
37	September	436,716	11,358	819	22	17
38	October	456,209	29,934	736	17	9
39	November	476,750	46,597	879	30	9
40	December	569,287	41,324	1,047	4	7
41	Total	6,166,822	407,167			

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Steam Electric Generating Plant Statistics

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

Line No.	Item (a)	Plant Name: 0	Plant Name: Big Sandy	Plant Name: Mitchell- Total	Plant Name: Mitchell-KEPCo Share [(a)]
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		6,472	7,039	7,039
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		24	180	87
12	Net Generation, Exclusive of Plant Use - kWh		1,101,730,000	4,090,448,000	2,045,224,000
13	Cost of Plant: Land and Land Rights		1,761,182	7,014,102.00	3,224,928
14	Structures and Improvements		24,646,311	202,144,011.00	77,654,994
15	Equipment Costs		162,341,321	2,108,428,744.00	986,581,372
16	Asset Retirement Costs		6,618,088	39,372,388.00	18,222,854
17	Total cost (total 13 thru 20)		195,366,902	2,356,959,245	1,085,684,148
18	Cost per KW of Installed Capacity (line 17/5) Including		696.4952	1,443.3308	1,328.8668
19	Production Expenses: Oper, Supv, & Engr		1,988,630	4,337,119	2,438,294
20	Fuel		37,737,308	191,336,426	95,587,892
21	Coolants and Water (Nuclear Plants Only)		0		0
22	Steam Expenses		347	10,105,777	5,052,896
23	Steam From Other Sources		0		0
24	Steam Transferred (Cr)		0		0
25	Electric Expenses		0	88,837	44,419
26	Misc Steam (or Nuclear) Power Expenses		2,136,377	8,383,098	4,129,478
27	Rents		0		0
28	Allowances		33,670	47,880	47,556
29	Maintenance Supervision and Engineering		266,759	2,813,686	1,410,672
30	Maintenance of Structures		747,434	2,093,722	1,047,030
31	Maintenance of Boiler (or reactor) Plant		1,728,633	23,940,815	11,752,846
32	Maintenance of Electric Plant		1,288,003	5,295,973	2,661,150
33	Maintenance of Misc Steam (or Nuclear) Plant		618,346	1,834,205	917,125
34	Total Production Expenses	0	46,545,507	250,277,538	125,089,358
35	Expenses per Net kWh		0.0422	0.0612	0.0612

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	9,564,007	1,805,085	65,970	902,543	32,985
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,196,000	12,378	138,411	12,378	138,411
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.522	91.117	109.113	91.117	109.113
41	Average Cost of Fuel per Unit Burned	3.621	95.061	113.061	95.061	113.061
42	Average Cost of Fuel Burned per Million BTU	3.027	3.840	19.449	3.840	19.449
43	Average Cost of Fuel Burned per kWh Net Gen	0.031	0.042	0.000	0.042	0.000
44	Average BTU per kWh Net Generation	10,232	11,011	0.000	11,011	0.000

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: PlantName
Plant Name: Mitchell - This plant is owned jointly by Respondent and Wheeling Power Company, also a subsidiary of American Electric Power, Inc.

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Hydroelectric Generating Plant Statistics

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 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 (total 13 thru 20)	
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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	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 (total 13 thru 20)	
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

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
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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													
Page 410-411													

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a genera ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specif and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generator whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Othe Cost Associ with S Genera Pow (Dolla (o)
35	TOTAL			0	0	0	0	0	0	0	0	0	0	0	

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
1	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) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	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	32.76	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	0135 WOOTEN	ARNOLD DELVINTA (LGE)	161.00	161.00	1	1.09	0	1	795 KCM ACSR			
14	0136 WOOTEN EXTENSION		161.00	161.00	1	0.04	0	1	795 KCM ACSR			
15	0143 HAZARD	WOOTON	161.00	161.00	1	0.60	0	1	795 KCM ACSR			
16	0143 HAZARD	WOOTON	161.00	161.00	1	0.98	0	2	795 KCM ACSR			
17	0143 HAZARD	WOOTON	161.00	161.00	3	0.26	0	2	795 KCM ACSR			
18	0143 HAZARD	WOOTON	161.00	161.00	3	1.16	0	1	795 KCM ACSR			
19	0143 HAZARD	WOOTON	161.00	161.00	2	3.58	0	1	795 KCM ACSR			
20	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	3	12.08	0	1	2-556.5 KCM ACSR			
21	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	3	14.77	0	2	795 KCM ACSR			
22	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	0	0.00	0	0	2-556.5 KCM ACSR			
23	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	3	0.32	0	1	1272 ACSS			
24	0101 BIG SANDY, KY	W HUNTINGTON, WV	138.00	138.00	3	0.33	0	1	1033.5 KCM ACSR			
25	0102 BELLEFONTE, KY	N PROCTORVILLE, OH	138.00	138.00	3	0.81	0	2	795 KCM ACSR			
26	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	3	5.91	0	1	397.5 MCMCU			
27	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	3	23.25	0	1				
28	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	3	2.30	0	1	636 MCMA			
29	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	1	16.09	17	1				
30	0107 LOGAN, WV	SPRIGG, KY	138.00	138.00	3	0.48	0	2	397 MCMA			
31	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	1.48	0	1	954KCM ACSR			
32	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	3.31	0	1	795KCM 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	3	30.88	0	1	636KCM ACSR			
34	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	22.86	0	1	636KCM ACSR			
35	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	1	0.01	0	1	636KCM ACSR			
36	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	3	0.71	14	1	795 MCMA			
37	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	1	0.38	0	1				
38	0113 CHADWICK	KY ELECTRIC STEEL	138.00	138.00	1	8.09	0	1	795 MCMA			
39	0115 CHADWICK	COALTON	138.00	138.00	1	0.98	0	1	795 MCMA			
40	0133 CHADWICK EXTENSION		138.00	138.00		1.06	0	1	795KCM ACSR			
41	0117 MILBROOK PARK, OH	FULLERTON	138.00	138.00	1	5.08	2	1	556.5 MCM			
42	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	1	25.83	0	1	795 MCMA			
43	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	3	0.63	0	0	1590 KCM			
44	0120 HATFIELD	SPRIGG	138.00	138.00	1	5.88	0	1	1033 MCM			
45	0121 HATFIELD	INEZ	138.00	138.00	1	14.67	0	1	1033.5 VAR			
46	0122 INEZ	LOVELY	138.00	138.00	1	6.86	0	1	1033.5 VAR			
47	0126 INEZ	MARTIKI	138.00	138.00	1	0.30	0	1	336.4 KCM ACSR			
48	0127 BIG SANDY	INEZ	138.00	138.00	3	25.08	0	1	795 MCMA			
49	0106 DORTON	FLEMING	138.00	138.00	1	6.85	0	1	795 MCMA			
50	0106 DORTON	FLEMING	138.00	138.00	3	0.83	0	0	795 MCMA			
51	0108 BEAVER CREEK	SPRIGG #1	138.00	138.00	1	32.60	0	1	397 MCMA			
52	0124 BIG SANDY	SOUTH NEAL	138.00	138.00	1	0.01	0	1	1033.5 VAR			
53	0109 BEAVER CREEK	SPRIGG #3	138.00	138.00		0.00	0	0				
54	0125 BELLEFONTE	AK STEEL OXYGEN PLANT	138.00	138.00	3	0.22	0	2	795 ACSR			
55	0130 JOHNS CREEK	SPRIGG	138.00	138.00	3	13.00	0	0	1033 MCM			
56	0131 BAKER	BIG SANDY EXT.	138.00	138.00	3	1.00	0	1	1351 KCM			
57	0131 BAKER	BIG SANDY EXT.	138.00	138.00	1	0.05	0	2	2 - 1351KCM ACSR			
58	0128 INEZ	JOHNS CREEK	138.00	138.00	3	17.00	0	0	2-556.5 MCM			
59	0129 BEAVER CREEK	JOHNS CREEK	138.00	138.00	3	22.25	0	2	1033.5KCM ACSR			
60	0132 GRANGSTON LOOP		138.00	138.00	3	0.84	0	2	556.5 KCM ACSR			
61	0137 HAYS BRANCH	MORGAN FORK	138.00	138.00	3	8.30	0	1	795 ACSR			
62	0138 SOFT SHELL	BEAVER CREEK	138.00	138.00	3	1.40	0	2	1590 ACSR			
63	0138 SOFT SHELL	SPICEWOOD	138.00	138.00	3	1.40	0	2	1590 ACSR			
64	0139 MORGAN FORK	BETSY LANE	138.00	138.00	3	0.10	0	1	795 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)
65	0139 MORGAN FORK	BEAVER CREEK	138.00	138.00	3	0.10	0	1	795 ACSR			
66	0140 BONNYMAN	SOFT SHELL	138.00	138.00	3	0.88	0	2	1590 KCM ACSS			
67	0140 BONNYMAN	SOFT SHELL	138.00	138.00	1	19.15	0	1	1590 KCM ACSS			
68	0154 Racoon Extension		138.00	138.00	1	0.20	0	2	1033.5KCM ACSR			
69	0119 BETSY LAYNE	ALLEN	46.00	138.00	1	5.89	0	1	795KCM ACSR			
70	0119 BETSY LAYNE	ALLEN	46.00	138.00	3	0.22	0	2	1033.5KCM ACSR			
71	0119 BETSY LAYNE	ALLEN	46.00	138.00	1	0.33	0	2	1033.5KCM ACSR			
72	0142 STANVILLE EXTENSION		138.00	138.00	1	0.42	0	1	1033.5KCM ACSR			
73	0117 FULLERTON	MILLBROOK	69.00	138.00	1	(0.05)	0	1	556 KCM ACSR			
74	0160 INEZ	MARTIN COUNTY SOLAR NO. 1	138.00	138.00	1	0.04	0	1	795 KCM ACSS			
75	0144 WOOTON	STINNETT	161.00	161.00	3	2.17	0	1	795 KCM ACSR			
76	0144 WOOTON	STINNETT	161.00	161.00	1	0.06	0	1	795 KCM ACSR			
77	0144 WOOTON	STINNETT	161.00	161.00	2	2.15	0	1	795 KCM ACSR			
78	0149 KEWANEE 138KV EXTENSION		138.00	138.00	1	0.21	0	2	1033 KCM ACSR			
79	0149 KEWANEE 138KV EXTENSION		138.00	138.00	3	4.86	0	2	1033 KCM ACSR			
80	0146 LESLIE 161KV EXTENSION		161.00	161.00	3	0.31	0	0	795 KCM ACSR			
81	0136 WOOTON 161KV EXTENSION		161.00	161.00	1	(0.12)	0	1	795 KCM ACSR			
82	LINES < 132KV		69.00	69.00		594.43	6.03	0				
83	Line cost and expense are	not available by individual								42,315,711	551,839,853	594,155,564
84	transmission line	Total shown in Column j - p										
36	TOTAL					1,275.52	39.03	92		42,315,711.00	551,839,853.00	594,155,564.00

Line No.	EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
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Line No.	EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
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77				
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82				
83	27,199	5,005,793		5,032,992
84				
36	27,199.00	5,005,793.00	0.00	5,032,992.00

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting co 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) appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Con
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)	Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1	0149 Kewanee 138kV Extension		0.21	1	1.00	2	2	1,033	ACSR		138						
2	0149 Kewanee 138kV Extension		4.86	3	1.00	2	2	1,033	ACSR		138	2,832,078	16,088,854	4,899,325		23,820,257	
44	TOTAL		5		2	4	4					2,832,078	16,088,854	4,899,325		23,820,257	

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
1	ALLEN (KP) - KY	Distribution		46.00	12.00	0.00	6.25	1			0	0.00
2	ALLEN (KP) - KY	Distribution		46.00	0.00	0.00	0.00			STATCAP	1	13.20
3	ASHLAND - KY	Distribution		69.00	0.00	0.00	0.00			STATCAP	1	16.20
4	ASHLAND - KY	Distribution		69.00	12.00	0.00	12.00	1			0	0.00
5	BARRENSHE - KY	Distribution		69.00	12.00	0.00	25.00	1			0	0.00
6	BEAVER CREEK - KY	Transmission		138.00	0.00	0.00	0.00			Air Core Reactor	3	
7	BEAVER CREEK - KY	Transmission		138.00	69.00	46.00	90.00	1			0	0.00
8	BEAVER CREEK - KY	Transmission		138.00	0.00	0.00	0.00			Reactor	3	
9	BEAVER CREEK - KY	Transmission		138.00	70.50	46.00	90.00	1			0	0.00
10	BEAVER CREEK - KY	Transmission		138.00	0.00	0.00	0.00			STATCAP	2	124.80
11	BEAVER CREEK - KY	Transmission		138.00	34.50	0.00	30.00	1			0	0.00
12	BECKHAM - KY	Distribution		138.00	34.50	0.00	30.00	1			0	0.00
13	BECKHAM - KY	Distribution		138.00	0.00	0.00	0.00			STATCAP	1	43.20
14	BEEFHIDE - KY	Distribution		138.00	34.00	0.00	12.00	1			0	0.00
15	BELFRY - KY	Distribution		46.00	12.00	0.00	10.50	1			0	0.00
16	BELHAVEN - KY	Distribution		138.00	13.09		12.00	1			0	0.00
17	BELLEFONTE - KY	Transmission		138.00	69.00	34.50	112.00	1			0	0.00
18	BELLEFONTE - KY	Transmission		138.00	69.50	35.00	117.60	1			0	0.00
19	BELLEFONTE - KY	Transmission		69.00	0.00	0.00	0.00			STATCAP	1	14.40
20	BELLEFONTE - KY	Transmission		138.00	13.09	0.00	12.00	1			0	0.00
21	BIG SANDY 138KV - KY	Transmission		138.00	34.50	0.00	20.00	1			0	0.00
22	BIG SANDY 138KV - KY	Transmission		138.00	13.09	0.00	20.00	1			0	0.00
23	BIG SANDY 138KV - KY	Transmission		138.00	0.00	0.00	0.00			Air Core Reactor	3	
24	BIG SANDY 138KV - KY	Transmission		138.00	69.50	13.20	128.80	1			0	0.00
25	BLUE GRASS - KY	Distribution		69.00	12.00	0.00	10.50	1			0	0.00
26	BONNYMAN - KY	Transmission		138.00	70.50	13.00	130.00	1			0	0.00
27	BONNYMAN - KY	Transmission		69.00	34.50	0.00	30.00	1			0	0.00
28	BULAN - KY	Distribution		69.00	12.00	0.00	9.38	1			0	0.00
29	BURDINE - KY	Distribution		46.00	12.00	0.00	7.50	1			0	0.00
30	BUSSEYVILLE - KY	Distribution		138.00	34.50	0.00	55.00	2			0	0.00
31	CANNONSBURG - KY	Distribution		69.00	36.20	0.00	18.00	1			0	0.00
32	CEDAR CREEK - KY	Transmission		138.00	69.50	46.00	54.00	1			0	0.00
33	CHADWICK - KY	Transmission		138.00	69.00	34.50	200.00	1			0	0.00
34	CHAVIES - KY	Distribution		69.00	0.00	0.00	0.00			STATCAP	1	9.60
35	CHAVIES - KY	Distribution		69.00	13.09	0.00	3.75	1			0	0.00
36	COALTON - KY	Distribution		69.00	0.00	0.00	0.00			STATCAP	1	14.40
37	COALTON - KY	Distribution		69.00	12.00	0.00	25.00	1			0	0.00

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
38	COLEMAN - KY	Distribution		69.00	34.50	0.00	20.00	1			0	0.00
39	COLEMAN - KY	Distribution		69.00	12.00	0.00	3.75	1			0	0.00
40	COLLIER - KY	Distribution		69.00	34.00	0.00	25.00	1			0	0.00
41	COLLIER - KY	Distribution		69.00	0.00	0.00	0.00			STATCAP	1	9.60
42	COMBS - KY	Distribution		69.00	0.00	0.00	0.00			STATCAP	1	13.20
43	COMBS - KY	Distribution		69.00	13.09	0.00	7.50	1			0	0.00
44	DAISY - KY	Distribution		69.00	12.00	0.00	4.70	1			0	0.00
45	DAISY - KY	Distribution		69.00	0.00	0.00	0.00			STATCAP	1	13.20
46	DEWEY - KY	Transmission		69.00	0.00	0.00	0.00			STATCAP	1	27.00
47	DEWEY - KY	Transmission		138.00	34.50	0.00	25.00	1			0	0.00
48	DEWEY - KY	Transmission		138.00	69.00	12.00	90.00	1			0	0.00
49	DORTON - KY	Transmission		138.00	70.50	46.00	144.00	2			0	0.00
50	DRAFFIN - KY	Distribution		46.00	12.00	0.00	10.50	1			0	0.00
51	EAST PRESTONSBURG - KY	Distribution		46.00	12.00	0.00	20.00	1			0	0.00
52	ELWOOD (KP) - KY	Distribution		46.00	0.00	0.00	0.00			STATCAP	1	14.40
53	ELWOOD (KP) - KY	Distribution		46.00	34.50	6.50	25.00	1			0	0.00
54	ENGLE - KY	Distribution		69.00	34.50	0.00	20.00	1			0	0.00
55	FALCON - KY	Distribution		69.00	46.00	0.00	20.00	1			0	0.00
56	FEDS CREEK - KY	Distribution		69.00	12.00	0.00	22.34	1			0	0.00
57	FISHTRAP - KY	Distribution		69.00	12.00	0.00	3.75	1			0	0.00
58	FORTY SEVENTH STREET - KY	Distribution		69.00	13.09	0.00	12.00	1			0	0.00
59	GARRETT (KP) - KY	Transmission		46.00	12.00	0.00	10.50	1			0	0.00
60	GRAHN - KY	Distribution		69.00	12.00	0.00	3.13	1			0	0.00
61	GRAYS BRANCH - KY	Distribution		69.00	12.00	0.00	5.00	1			0	0.00
62	GRAYSON - KY	Distribution		69.00	12.00	0.00	20.00	1			0	0.00
63	HADDIX - KY	Distribution		69.00	36.20	0.00	15.00	1			0	0.00
64	HADDIX - KY	Distribution		69.00	0.00	0.00	0.00			STATCAP	1	5.40
65	HATFIELD (KP) - KY	Transmission		138.00	69.00	46.00	130.00	1			0	0.00
66	HAYWARD - KY	Distribution		69.00	13.09	0.00	9.38	1			0	0.00
67	HAZARD - KY	Transmission		138.00	70.50	13.09	78.00	1			0	0.00
68	HAZARD - KY	Transmission		138.00	0.00	0.00	0.00			STATCAP	1	46.10
69	HAZARD - KY	Transmission		34.50	12.00	0.00	9.38	1			0	0.00
70	HAZARD - KY	Transmission		161.00	138.00	13.09	210.00	0	1		0	0.00
71	HAZARD - KY	Transmission		138.00	36.20		18.00	1			0	0.00
72	HAZARD - KY	Transmission		138.00	0.00	0.00	0.00			XSLR - 0.6mH / 480A	3	0.11
73	HAZARD - KY	Transmission		161.00	138.00	13.09	3684.00	18			0	0.00
74	HAZARD - KY	Transmission		161.00	70.50	13.09	1842.00	9			0	0.00
75	HENRY CLAY - KY	Distribution		46.00	0.00	0.00	0.00			STATCAP	1	9.60
76	HENRY CLAY - KY	Distribution		46.00	34.50	0.00	30.00	1			0	0.00
77	HIGHLAND (KP) - KY	Distribution		69.00	0.00	0.00	0.00			STATCAP	1	
78	HIGHLAND (KP) - KY	Distribution		69.00	13.09	0.00	25.00	1			0	0.00
79	HITCHINS - KY	Distribution		69.00	13.09	0.00	25.00	1			0	0.00
80	HOODS CREEK - KY	Distribution		69.00	13.09	0.00	7.50	1			0	0.00
81	HOWARD COLLINS - KY	Distribution		69.00	13.09	0.00	12.00	1			0	0.00
82	HOWARD COLLINS - KY	Distribution		69.00	12.00	0.00	10.50	1			0	0.00
83	INDEX - KY	Distribution		69.00	12.00	0.00	9.40	1			0	0.00
84	INEZ - KY	Transmission		138.00	70.50	13.09	54.00	1			0	0.00
85	INEZ - KY	Transmission		138.00	0.00	0.00	0.00			STATCAP	2	105.60
86	JACKSON - KY	Distribution		69.00	12.00	0.00	7.00	1			0	0.00

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
87	JACKSON - KY	Distribution		69.00	13.09	0.00	7.50	1			0	0.00
88	JACKSON - KY	Distribution		69.00	0.00	0.00	0.00			STATCAP	1	9.60
89	JEFF - KY	Distribution		69.00	36.20	0.00	30.00	1			0	0.00
90	JENKINS - KY	Distribution		69.00	12.00	0.00	10.50	1			0	0.00
91	JOHNS CREEK - KY	Transmission		138.00	70.50	36.20	54.00	1			0	0.00
92	JOHNS CREEK - KY	Transmission		69.00	0.00	0.00	0.00			STATCAP	1	9.60
93	JOHNS CREEK - KY	Transmission		138.00	0.00	0.00	0.00			STATCAP	1	52.80
94	KENWOOD - KY	Distribution		46.00	12.00	0.00	20.00	1			0	0.00
95	KENWOOD - KY	Distribution		46.00	0.00	0.00	0.00			STATCAP	1	7.20
96	KEWANEE - KY	Distribution		138.00	0.00	0.00	0.00			STATCAP	1	34.60
97	KEWANEE - KY	Distribution		138.00	0.00	0.00	0.00			XSLR - 0.6mH / 480A	3	
98	KIMPER - KY	Distribution		69.00	12.00	0.00	9.38	1			0	0.00
99	LESLIE - KY	Transmission		161.00	70.50	40.73	520.00	4			0	0.00
100	LESLIE - KY	Transmission		69.00	0.00	0.00	0.00			1200A Air-Core Reactor	3	
101	LESLIE - KY	Transmission		161.00	70.50	13.09	520.00	4			0	0.00
102	LESLIE - KY	Transmission		69.00	0.00	0.00	0.00			STATCAP	1	14.40
103	LESLIE - KY	Transmission		69.00	34.50	0.00	30.00	1			0	0.00
104	LOVELY - KY	Distribution		138.00	36.20	0.00	18.00	1			0	0.00
105	MANSBACH - KY	Distribution		69.00	4.00	0.00	9.38	1			0	0.00
106	MAYKING - KY	Distribution		69.00	12.00	0.00	20.00	1			0	0.00
107	MAYO TRAIL - KY	Distribution		69.00	13.09	0.00	25.00	1			0	0.00
108	MCKINNEY - KY	Distribution		34.50	12.00	0.00	6.67	1			0	0.00
109	MCKINNEY - KY	Distribution		46.00	34.00	0.00	20.00	1			0	0.00
110	MIDDLE CREEK - KY	Distribution		46.00	12.00	0.00	3.75	1			0	0.00
111	MORGAN FORK - KY	Transmission		138.00	0.00	0.00	0.00			STATCAP	1	43.20
112	NEW CAMP - KY	Distribution		69.00	13.09	0.00	40.00	2			0	0.00
113	OLIVE HILL - KY	Distribution		69.00	4.00	0.00	5.00	1			0	0.00
114	OLIVE HILL - KY	Distribution		69.00	12.00	0.00	7.50	1			0	0.00
115	PRESTONSBURG - KY	Distribution		46.00	0.00	0.00	0.00			STATCAP	1	9,600.00
116	PRESTONSBURG - KY	Distribution		46.00	13.09	0.00	10.00	1			0	0.00
117	PRINCESS - KY	Distribution		69.00	34.50	0.00	20.00	1			0	0.00
118	PRINCESS - KY	Distribution		69.00	0.00	0.00	0.00			STATCAP	1	21.60
119	RACELAND - KY	Distribution		69.00	2.40	0.00	7.50	1			0	0.00
120	REEDY COAL - KY	Distribution		69.00	34.00	0.00	20.00	1			0	0.00
121	RUSSELL - KY	Distribution		69.00	12.00	0.00	12.00	1			0	0.00
122	RUSSELL FORK - KY	Distribution		69.00	12.00		3.75	1			0	0.00
123	SALISBURY (KP) - KY	Distribution		46.00	13.09	0.00	20.00	1			0	0.00
124	SECOND FORK - KY	Distribution		69.00	0.00	0.00	0.00			STATCAP	1	14.40
125	SECOND FORK - KY	Distribution		69.00	13.09	0.00	7.50	1			0	0.00
126	SHAMROCK - KY	Distribution		69.00	34.50	0.00	10.50	1			0	0.00
127	SIDNEY - KY	Distribution		69.00	13.09	0.00	12.00	1			0	0.00
128	SLEMP - KY	Distribution		69.00	34.00	0.00	20.00	1			0	0.00
129	SLEMP - KY	Distribution		69.00	36.20	0.00	7.50	1			0	0.00
130	SOFT SHELL - KY	Distribution		138.00	34.50	0.00	30.00	1			0	0.00
131	SOUTH PIKEVILLE - KY	Distribution		69.00	13.09	0.00	25.00	1			0	0.00
132	SOUTH SHORE - KY	Distribution		69.00	13.09	0.00	7.50	1			0	0.00
133	STINNETT - KY	Distribution		161.00	34.00	7.20	14.93	1			0	0.00
134	STINNETT - KY	Distribution		161.00	34.50	7.20	22.40	1			0	0.00

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
135	STINNETT - KY	Distribution		161.00	34.50	7.20	22.40	0	1		0	0.00
136	STONE - KY	Transmission		138.00	70.50	46.00	90.00	1			0	0.00
137	TENTH STREET - KY	Distribution		69.00	13.09	0.00	25.00	1			0	0.00
138	THELMA - KY	Transmission		46.00	0.00	0.00	0.00			STATCAP	1	7.20
139	THELMA - KY	Transmission		138.00	69.00	12.00	90.00	1			0	0.00
140	THELMA - KY	Transmission		138.00	69.00	46.00	70.00	1			0	0.00
141	THELMA - KY	Transmission		138.00	0.00	0.00	0.00			STATCAP	1	32.40
142	TOM WATKINS - KY	Distribution		69.00	12.00	0.00	10.50	1			0	0.00
143	TOPMOST - KY	Distribution		138.00	13.09	0.00	20.00	1			0	0.00
144	TYGART - KY	Distribution		69.00	13.09	0.00	54.00	4			0	0.00
145	VICCO - KY	Distribution		138.00	34.50	0.00	18.00	1			0	0.00
146	WEEKSBURY - KY	Distribution		69.00	13.09	0.00	5.00	1			0	0.00
147	WEST PAINTSVILLE - KY	Distribution		69.00	12.00	0.00	25.00	1			0	0.00
148	WHITESBURG - KY	Distribution		69.00	12.00	0.00	25.00	1			0	0.00
149	WHITESBURG - KY	Distribution		69.00	0.00	0.00	0.00			STATCAP	1	13.20
150	WHITESBURG - KY	Distribution		69.00	13.09	0.00	7.50	1			0	0.00
151	WORTHINGTON - KY	Distribution		69.00	12.00	0.00	1.50	1			0	0.00
152	TotalTransmissionSubstationMember											10,340
153	Total											10,340

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Administrative and General Expenses - Maintenance	AEPSC	935	1,346,672
3	Administrative and General Expenses - Operation	AEPSC	920-926,928,930,931,932,910	1,989,506
4	AEP Transmission	AEPSC	920,923	376,755
5	Central Machine Shop	APCo	107,108,500,506,512	417,694
6	Chief Commercial Officer	AEPSC	920,923	355,057
7	Chief Executive Officer	AEPSC	920,923	3,288,621
8	Chief Financial Officer	AEPSC	920,923	6,837,073
9	Chief Info & Tech Officer	AEPSC	920,923	1,402,161
10	Construction Services	AEPSC	107,108	26,743,052
11	Customer Accounts Expenses	AEPSC	901-905	3,450,291
12	Distribution Expenses - Maintenance	AEPSC	590-593,595,597,598	1,129,543
13	Distribution Expenses - Operation	AEPSC	580,582-588	1,769,207
14	Factored Customer A/R Bad Debts	AEPSC	426	1,740,537
15	Factored Customer A/R Expense	AEPSC	426	3,247,182
16	Fuel & Storeroom Services	AEPSC	152,163	1,154,335
17	Materials and Supplies	APCo	107,108,154,184,512-514,560,571,588,595,598,935	502,075
18	Materials and Supplies	OPCo	107, 184, 513, 560, 570, 571, 591, 592, 935	2,664,052
19	O&M Services for Jointly Owned Facility - Mitchell	WPCo	107,108,154,186,408,417,421,426, 500-502,505-506, 510-514,557,920-926,928,930,931,935	53,060,522
20	Other Power Supply Expenses	AEPSC	556,557	294,277
21	Research and Other Services	AEPSC	183,186,188	764,124
22	Steam Power Generation - Operation	AEPSC	500-502, 506	1,569,781
23	Transmission Expenses - Maintenance	AEPSC	568-573	1,568,544
24	Transmission Expenses - Operation	AEPSC	560-564, 566	3,823,256
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Building and Property Leases	AEPSC	454	607,078
22	Fleet and Vehicle Charges	AEPSC	See Footnote	1,643,493
23	Materials and Supplies	APCo	154	418,996
24	Taxes Other Than Income taxes	WPCo	[(a)] 408	2,743,719
25	Use of Jointly Owned Facility	KYTCo	454	496,180
42				

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

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.