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

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Kentucky Power Company	End of: 2021/ Q4

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

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

GENERAL INFORMATION

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.

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:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

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

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

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

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

The CPA Certification Statement should:

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

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

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

explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

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

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

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

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

When to Submit

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

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

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

Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying

Notes to Financial Statements -- 122-123

The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions,

reporting period, and use for statement of income accounts the current year's year to date amounts.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods.

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

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.

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:

'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;

'Person' means an individual or a corporation;

'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;

'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; ......

"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

'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.

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.

adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

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..."

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

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

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: 2021/ 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) 04/06/2022

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	03 Signature Jeffrey W Hoersdig	04 Date Signed (Mo, Da, Yr) 04/07/2022
02 Title Assistant Controller		

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

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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".

	Transmission Service and Generation Interconnection Study Costs		
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
49	Transmission of Electricity by ISO/RTOs	331	
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	

60	**Monthly ISO/RTO Transmission System Peak Load**	400a	
61	**Electric Energy Account**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	
64	**Hydroelectric Generating Plant Statistics**	406	
65	**Pumped Storage Generating Plant Statistics**	408	
66	**Generating Plant Statistics Pages**	410	
0	**Energy Storage Operations (Large Plants)**	414	
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		

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

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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.

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: 04/06/2022	Year/Period of Report End of: 2021/ 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: 04/06/2022	Year/Period of Report End of: 2021/ 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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FERC FORM No. 1 (ED. 12-96)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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				

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

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OfficerTitle

The following table provides summary information concerning compensation earned by our Chief Executive Officer, our Chief Financial Officer and the three other most highly compensated executive officers, to whom we refer collectively as the named executive officers.

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)	Stock Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)(3)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(4)	All Other Compensation ($)(5)	Total ($)
Nicholas K. Akins								
Chair of the Board and Chief Executive Officer	2021	1,515,808		9,976,149	2,850,000	461,732	247,526	15,051,215
Julia A. Sloat								
Executive Vice President and Chief Financial Officer	2021	602,308		1,628,789	637,350	76,622	58,042	3,003,111
Lisa M. Barton								
Executive Vice President and Chief Operating Officer	2021	803,077		2,443,104	890,000	165,173	88,143	4,389,497
David M. Feinberg								
Executive Vice President, General Counsel and Secretary	2021	696,669		1,527,000	690,000	93,625	98,652	3,105,946
Charles E. Zebula								
Executive Vice President - Portfolio Optimization	2021	579,219		1,323,341	640,000	42,921	71,745	2,657,226
Brian X. Tierney								
Former Executive Vice President - Strategy	2021	410,000	—	2,675,947	—	—	732,507	3,818,454
Mark C. McCullough								
Former Executive Vice President - Energy Delivery	2021	322,327	—	1,823,341	—	—	1,115,159	3,260,827

(1) Amounts in the salary column are composed of executive salaries earned for the year shown, which include 261 days of pay for 2021. This is one day more than the standard 260 calendar work days and holidays in a year.

(2) 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, 2021 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 2021 performance shares will be based on three measures: a Board approved cumulative operating earnings per share measure (Cumulative EPS 50%), a total shareholder return measure (Relative TSR 40%) and a carbon free capacity mix (Carbon Free Capacity 10%). The grant date fair value of the 2021 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 2021 performance shares that are based on Cumulative EPS measured on the grant date was $7,350,035 for Mr. Akins; $1,200,060 for Ms. Sloat; $1,800,012 for Ms. Barton; $1,125,066 for Mr. Feinberg; $975,000 for Mr. Zebula; $1,500,036 for Mr. Tierney; and $975,000 for Mr. McCullough. The maximum amount payable for the 2021 performance shares that are based on Carbon Free Capacity is equal to $1,470,007 for Mr. Akins; $240,012 for Ms. Sloat; $360,002 for Ms. Barton; $225,013 for Mr. Feinberg; $195,000 for Mr. Zebula; $300,007 for Mr. Tierney; and $195,000 for Mr. McCullough. The grant date fair value of the 2021 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 2019 performance shares are included in the Option Exercises and Stock Vested for 2021 table.

(3) The amounts shown in this column reflect annual incentive compensation paid for the year shown.

(4) 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. Negative values of ($404,033) and ($269,258) for Messrs. Tierney and McCullough, respectfully, were replaced with $0 for the purposes of the Summary Compensation Table. These negative values were caused by their severance from the company during 2021, which resulted in the removal of projected benefits that would have been attributable to eligible earnings for future years under these plans. See the Pension Benefits for 2021 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, 2021 for a discussion of the relevant assumptions. None of the named executive officers received preferential or above-market earnings on deferred compensation.

(5) Amounts shown in the All Other Compensation column for 2021 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) perquisites, (d) vacation payout, and (e) severance benefits. The 2021 values for these items are listed in the following table:

Type	Nicholas K. Akins	Julia A. Sloat	Lisa M. Barton	David M. Feinberg	Charles E. Zebula	Brian X. Tierney	Mark C. McCullough
Retirement Savings Plan Match	13,050	13,050	13,050	13,050	13,050	13,050	13,050
Supplemental Retirement Savings Plan Match	212,400	31,272	61,373	56,295	46,665	53,097	35,468
Perquisites	22,076	13,720	13,720	29,307	12,030	6,360	6,804
Vacation Payout	—	—	—	—	—	41,000	60,837
Severance	—	—	—	—	—	619,000	999,000
Total	**$ 247,526**	**$ 58,042**	**$ 88,143**	**$ 98,652**	**$ 71,745**	**$ 732,507**	**$ 1,115,159**

(6) Ms. Sloat's compensation is provided only for the years in which she was an executive officer of the Company.

Perquisites provided in 2021 included: financial counseling and tax preparation services and, for Mr. Akins, director's group travel accident insurance premium. 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).

Mr. Akins has entered into an Aircraft Time Sharing Agreement that allows him to use our corporate aircraft for personal use for a limited number of hours each year. The Aircraft Time Sharing Agreement requires Mr. Akins to reimburse the Company for the cost of his personal use of corporate aircraft in accordance with limits set forth in Federal Aviation Administration regulations. Mr. Akins reimbursed the Company all incremental costs incurred in connection with personal flights under the Aircraft Timesharing Agreement including fuel, oil, hangar costs, crew travel expenses, catering, landing fees and other incremental airport fees. Accordingly, no value is shown for these amounts in the Summary Compensation Table. If the aircraft flies empty before picking up or after dropping off Mr. Akins at a destination on a personal flight, the cost of the empty flight is included in the incremental cost for which Mr. Akins reimburses the Company. Since AEP aircraft are used predominantly for business purposes, we do not include fixed costs that do not change in amount based on usage, such as depreciation and pilot salaries.

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	Nicholas K. Akins, Chairman of the Board and Chief Executive Officer	Columbus, Ohio	false	false
2	Lisa M. Barton, Vice President	Columbus, Ohio	false	false
3	Paul Chodak, Vice President	Columbus, Ohio	false	false
4	David M. Feinberg, Secretary	Columbus, Ohio	false	false
5	D Brett Mattison, President and Chief Operating Officer	Columbus, Ohio	false	false
6	Charles R. Patton	Columbus, Ohio	false	false
7	Therace M. Risch, Vice President	Columbus, Ohio	false	false
8	Julia A. Sloat, Chief Financial Officer and Vice President	Columbus, Ohio	false	false
9	Toby L. Thomas, Vice President	Columbus, Ohio	false	false

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

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

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

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	20211221-5274	12/21/2021	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
2	20211101-5315	11/01/2021	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
3	20210525-5243	05/25/2021	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14

FERC FORM NO. 1 (NEW. 12-08)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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: 04/06/2022	Year/Period of Report End of: 2021/ 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.

Community	Period of Franchise & Termination	Consideration
City of Ashland	Franchise renewal expiring on August 26, 2031	None
City of Catlettsburg	Franchise renewal expiring on August 11, 2031	None

None

None

None

None

$150M Term Loan - KY State Commission Authority: Case No. 2021-00131
Issued: 6/17/2021
Maturity: 6/17/2023

None

Effective Date	Status	Business Unit Operating Company, Location	Union Local #	Contract Or Wages	Total Personnel Represented	Settlement Amount %
5/1/21	Previously Negotiated and Ratified	Kentucky Power (Wires and Gen)	IBEW 978 (4 CBAs)	Wages	287%	
5/1/21	Previously Negotiated and Ratified	Kentucky Power Mitchell Plant	UWUA 492	Wages	129%	

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

None

Julia A Sloat, elected as Director & Chief Financial Officer effective 1/1/2021
Brian K West, elected as Vice President - Regulatory & Finance effective 1/1/2021
Julie A Sherwood, elected as Treasurer effective 1/1/2021
Daniel E Mueller, elected as Assistant Vice President – Tax effective 3/24/2021
D Brett Mattison, elected as Director effective 5/02/2021
Scott P Moore, elected as Vice President effective 5/19/2021
Wade A Smith, resigned as Vice President effective 5/01/2021
Therace M Risch, elected as Director and Vice President effective 7/03/2021
Toby L Thomas, elected as Director and Vice President effective 7/31/2021
Charles E Zebula, elected as Vice President effective 7/03/2021
Brian X Tierney, resigned as Director and Vice President effective 7/1/2021
Mark C. McCullough, resigned as Director and Vice President effective 7/30/2021

Proprietary capital ratio exceeds 30%

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

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	3,147,348,972	3,012,853,573
3	Construction Work in Progress (107)	200	95,340,895	83,081,419
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,242,689,868	3,095,934,992
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	1,159,640,985	1,089,649,675
6	Net Utility Plant (Enter Total of line 4 less 5)		2,083,048,883	2,006,285,317
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)		2,083,048,883	2,006,285,317
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		6,554,403	6,670,698
19	(Less) Accum. Prov. for Depr. and Amort. (122)		151,941	159,698
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228	8,458,403	8,485,833
24	Other Investments (124)		1,804,869	1,878,654
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)		60,332,681	41,061,542
30	Long-Term Portion of Derivative Assets (175)			23,241

31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		76,998,414	57,960,270
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		763,386	1,532,625
36	Special Deposits (132-134)		14,266,645	148,617
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		15,642,267	9,998,566
41	Other Accounts Receivable (143)		56,847	79,616
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,389	87,345
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		24,535,392	19,924,250
45	Fuel Stock (151)	227	9,489,812	21,135,130
46	Fuel Stock Expenses Undistributed (152)	227	599,696	1,351,909
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	20,420,653	19,725,867
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	8,552,442	8,620,509
53	(Less) Noncurrent Portion of Allowances	228	8,458,403	8,485,833
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)		1,995,946	2,113,467
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		2,619,316	3,130,437
61	Accrued Utility Revenues (173)		16,646,864	18,917,529
62	Miscellaneous Current and Accrued Assets (174)			
63	Derivative Instrument Assets (175)		5,986,480	3,174,776
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			23,241
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)		113,113,955	101,256,879
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		1,895,122	2,349,613
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	613,089,054	605,197,569
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,335,712	1,211,534
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		1,634	
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	22,792,880	22,532,958
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		367,354	401,005
82	Accumulated Deferred Income Taxes (190)	234	94,062,449	101,993,170
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		733,544,206	733,685,849
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,006,705,458	2,899,188,315

FERC FORM No. 1 (REV. 12-03)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	0	
4	Capital Stock Subscribed (202, 205)		0	
5	Stock Liability for Conversion (203, 206)		0	
6	Premium on Capital Stock (207)		0	
7	Other Paid-In Capital (208-211)	253	526,135,279	526,135,279
8	Installments Received on Capital Stock (212)	252	0	
9	(Less) Discount on Capital Stock (213)	254	0	
10	(Less) Capital Stock Expense (214)	254b	0	
11	Retained Earnings (215, 215.1, 216)	118	296,020,207	245,870,395
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	0	
13	(Less) Reaquired Capital Stock (217)	250	0	
14	Noncorporate Proprietorship (Non-major only) (218)		0	
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	1,749,841	878,395
16	Total Proprietary Capital (lines 2 through 15)		874,355,328	823,334,069
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	0	
19	(Less) Reaquired Bonds (222)	256	0	
20	Advances from Associated Companies (223)	256	0	
21	Other Long-Term Debt (224)	256	1,105,000,000	995,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	
24	Total Long-Term Debt (lines 18 through 23)		1,105,000,000	995,000,000
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		10,678,099	12,248,637
27	Accumulated Provision for Property Insurance (228.1)		0	
28	Accumulated Provision for Injuries and Damages (228.2)		2,096,019	2,173,461
29	Accumulated Provision for Pensions and Benefits (228.3)		3,818,077	3,762,571

30	Accumulated Miscellaneous Operating Provisions (228.4)		0	
31	Accumulated Provision for Rate Refunds (229)		0	15,313
32	Long-Term Portion of Derivative Instrument Liabilities		405	18,809
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	
34	Asset Retirement Obligations (230)		17,696,994	24,565,645
35	Total Other Noncurrent Liabilities (lines 26 through 34)		34,289,595	42,784,436
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		0	
38	Accounts Payable (232)		52,836,888	47,156,732
39	Notes Payable to Associated Companies (233)		47,895,489	65,646,793
40	Accounts Payable to Associated Companies (234)		42,223,069	24,861,939
41	Customer Deposits (235)		32,431,608	30,773,898
42	Taxes Accrued (236)	262	44,350,258	36,555,700.00
43	Interest Accrued (237)		5,685,082	6,399,332
44	Dividends Declared (238)		0	
45	Matured Long-Term Debt (239)		0	
46	Matured Interest (240)		0	
47	Tax Collections Payable (241)		2,710,271	2,137,288
48	Miscellaneous Current and Accrued Liabilities (242)		16,479,391	19,615,189
49	Obligations Under Capital Leases-Current (243)		2,964,248	3,161,375
50	Derivative Instrument Liabilities (244)		51,471	231,494
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		405	18,809
52	Derivative Instrument Liabilities - Hedges (245)		0	
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	
54	Total Current and Accrued Liabilities (lines 37 through 53)		247,627,370	236,520,932
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		162,588	159,427
57	Accumulated Deferred Investment Tax Credits (255)	266	0	
58	Deferred Gains from Disposition of Utility Plant (256)		0	
59	Other Deferred Credits (253)	269	2,559,807	4,061,753
60	Other Regulatory Liabilities (254)	278	211,496,606	249,280,078
61	Unamortized Gain on Reaquired Debt (257)		0	
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	28,546,787	30,144,934

63	Accum. Deferred Income Taxes-Other Property (282)		279,944,834	271,069,350
64	Accum. Deferred Income Taxes-Other (283)		222,722,543	246,833,338
65	Total Deferred Credits (lines 56 through 64)		745,433,165	801,548,879
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,006,705,458	2,899,188,316

FERC FORM No. 1 (REV. 12-03)

Page 112-113

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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 (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) 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) t 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

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

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)	Oth Utili Curr Year Dat (ir dolla (k)
1	UTILITY OPERATING INCOME										
2	Operating Revenues (400)	300	659,547,828	552,755,959			659,547,828	552,755,959			
3	Operating Expenses										
4	Operation Expenses (401)	320	391,618,340	279,714,467			391,618,340	279,714,467			
5	Maintenance Expenses (402)	320	64,352,871	61,895,188			64,352,871	61,895,188			
6	Depreciation Expense (403)	336	93,483,264	87,747,655			93,483,264	87,747,655			
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	155,861	283,687			155,861	283,687			
8		336	8,819,731	7,448,031			8,819,731	7,448,031			

	Amort. & Depl. of Utility Plant (404-405)										
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)		12,707,045	5,812,552			12,707,045	5,812,552			
13	(Less) Regulatory Credits (407.4)										
14	Taxes Other Than Income Taxes (408.1)	262	26,544,079	27,980,142			26,544,079	27,980,142			
15	Income Taxes - Federal (409.1)	262	(1,639,190)	(8,803,254)			(1,639,190)	(8,803,254)			
16	Income Taxes - Other (409.1)	262	337,063	162,982			337,063	162,982			
17	Provision for Deferred Income Taxes (410.1)	234, 272	59,974,621	228,550,788			59,974,621	228,550,788			
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	83,905,161	223,854,412			83,905,161	223,854,412			
19	Investment Tax Credit Adj. - Net (411.4)	266		(26)				(26)			
20	(Less) Gains from Disp. of Utility Plant (411.6)		9,877	8,686			9,877	8,686			
21	Losses from Disp. of Utility Plant (411.7)										
22	(Less) Gains from Disposition of Allowances (411.8)		8	85,944			8	85,944			
23	Losses from Disposition of Allowances (411.9)										
24	Accretion Expense (411.10)		613,105	699,963			613,105	699,963			

25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		573,090,361	467,581,749			573,090,361	467,581,749			
27	Net Util Oper Inc (Enter Tot line 2 less 25)		86,457,467	85,174,210			86,457,467	85,174,210			
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)		308,103	282,788							
34	(Less) Expenses of Nonutility Operations (417.1)		19	2							
35	Nonoperating Rental Income (418)		16,187	33,180							
36	Equity in Earnings of Subsidiary Companies (418.1)	119									
37	Interest and Dividend Income (419)		19,109	69,735							
38	Allowance for Other Funds Used During Construction (419.1)		1,821,825	1,169,836							
39	Miscellaneous Nonoperating Income (421)		58,006	672,626							
40	Gain on Disposition of Property (421.1)		515,942	47,839							
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		2,739,152	2,276,003							

42	Other Income Deductions										
43	Loss on Disposition of Property (421.2)		2,682	14							
44	Miscellaneous Amortization (425)										
45	Donations (426.1)		2,945,972	934,968							
46	Life Insurance (426.2)										
47	Penalties (426.3)		(105,164)	383							
48	Exp. for Certain Civic, Political & Related Activities (426.4)		308,201	260,769							
49	Other Deductions (426.5)		2,515,193	7,188,104							
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,666,884	8,384,237							
51	Taxes Applic. to Other Income and Deductions										
52	Taxes Other Than Income Taxes (408.2)	262	98,390	43,582							
53	Income Taxes-Federal (409.2)	262	(1,331,171)	(851,602)							
54	Income Taxes-Other (409.2)	262	(337,063)	82,044							
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	638,797	898,268							
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	1,216,770	227,350							
57	Investment Tax Credit Adj.-Net (411.5)										
58	(Less) Investment Tax Credits (420)										
59			(2,147,818)	(55,057)							

	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)											
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(779,914)	(6,053,176)								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		36,669,034	38,213,313								
63	Amort. of Debt Disc. and Expense (428)		480,846	478,688								
64	Amortization of Loss on Reaquired Debt (428.1)		33,651	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)		165,604	676,229								
68	Other Interest Expense (431)		(885,096)	(198,433)								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		936,297	1,098,919								
70	Net Interest Charges (Total of lines 62 thru 69)		35,527,741	38,104,529								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		50,149,812	41,016,505								
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)		50,149,812	41,016,505								

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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		245,870,395	204,805,591
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1	Adj to Retained Earnings			48,299
9	TOTAL Credits to Retained Earnings (Acct. 439)			48,299
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)		50,149,812	41,016,505
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)		296,020,207	245,870,395
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)		296,020,207	245,870,395
	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)		0	

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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)	50,149,812	41,016,505
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	102,497,472	95,517,989
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Regulatory Debits and Credits (Net)	12,707,045	5,812,552
5.2	Mark-to-Market of Risk Management Contracts	(2,991,726)	2,478,707
8	Deferred Income Taxes (Net)	(24,508,514)	5,367,293
9	Investment Tax Credit Adjustment (Net)		(26)
10	Net (Increase) Decrease in Receivables	(9,804,910)	4,629,131
11	Net (Increase) Decrease in Inventory	11,702,745	5,357,172
12	Net (Increase) Decrease in Allowances Inventory	68,067	74,705
13	Net Increase (Decrease) in Payables and Accrued Expenses	20,093,759	4,160,456
14	Net (Increase) Decrease in Other Regulatory Assets	(56,480,696)	(44,149,578)
15	Net Increase (Decrease) in Other Regulatory Liabilities	3,847,436	(616,430)
16	(Less) Allowance for Other Funds Used During Construction	1,821,825	1,169,836
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):	[(a)](30,419,418)	(41,973,111)
18.2	Customer deposits	1,657,710	(179,905)
18.3	Over/Under Recovered Fuel, Net	(8,529,459)	90,643
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	68,167,498	76,416,267
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(167,164,664)	(155,514,799)

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	(1,821,825)	(1,169,836)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
31.2	Acquired Assets	(206,212)	(279,861)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(165,549,051)	(154,624,823)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	[(b)]1,075,489	824,865
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		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		8,299
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Other (Provide details in footnote):	3,221,405	572,890
53.2	(Increase) Decrease in Other Special Deposits	(74,930)	99,307
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(161,327,087)	(153,119,462)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	150,000,000	125,000,000
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	(26,355)	(381,248)
66	Net Increase in Short-Term Debt (c)		

67	Other (provide details in footnote):		
67.1	Proceed on Capital leaseback	168,008	296,198
67.2	Notes Payable to Associated Companies		
70	Cash Provided by Outside Sources (Total 61 thru 69)	150,141,653	124,914,950
72	Payments for Retirement of:		
73	Long-term Debt (b)	(40,000,000)	
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	(17,751,304)	(47,527,971)
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)	92,390,349	77,386,978
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)	(769,240)	683,784
88	Cash and Cash Equivalents at Beginning of Period	1,532,625	848,842
90	Cash and Cash Equivalents at End of Period	763,385	1,532,625

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

	2021 Cash Flow Incr / (Decr)	2020 Cash Flow Incr / (Decr)
Utility Plant, Net	$ (13,107,143)	$ (11,000,069)
Property and Investments, Net	$ 182,324	(64,318)
Margin Deposits	(14,043,098)	370,128
Prepayments	(1,225,157)	(4,378,033)
Accrued Utility Revenues, Net	2,270,665	(5,367,962)
Unamortized Debt Expense	480,846	478,690
Other Deferred Debits, Net	(293,644)	(235,154)
Proprietary Capital, Net	—	48,298
Accumulated Provisions - Misc	(10,435)	1,784,567
Current and Accrued Liabilities, Net	(875,480)	(2,051,614)
Other Deferred Credits, Net	(3,798,296)	(21,557,644)
Total	**$ (30,419,418)**	**$ (41,973,111)**

(b) Concept: ProceedsFromDisposalOfNoncurrentAssets

	2021 Cash Flow Incr / (Decr)	2020 Cash Flow Incr / (Decr)
Sale of meters between various operating companies	$ 22,701	$ 23,372
Sale of transformers between various operating companies	408,442	406,051
Sale of Transformer S/N GT03806, CAT ID 0710054901 (Baker 765/345kV Substation) to AEPTN (Walnut Street Substation).	—	395,442
Sale of 1.18+/- acres located at 332 South May Trail, Pikeville, Kentucky - to third party	530,000	—
Land Sale Proceeds - Dumont / Lakeville Site, Dumont UHV Test Facility - to third party	114,346	—
Total	**$ 1,075,489**	**$ 824,865**

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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 Cormmission 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.
COVID-19	Coronavirus 2019, a highly infectious respiratory disease. In March 2020, the World Health Organization declared COVID-19 a worldwide pandemic.
CWIP	Construction Work in Progress.

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.
ITC	Investment Tax Credit.
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.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NO_x	Nitrogen oxide.
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 within the AEP consolidation.
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.
PUCO	Public Utilities Commission of Ohio.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SSO	Standard service offer.
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.
WVPSC	West Virginia Public Service Commission.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 165,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

Under a unit power agreement with AEGCo, an affiliated company, KPCo purchases 393 MWs of Rockport Plant capacity which is 30% of AEGCo’s 50% share of the 2,620 MW Rockport Plant. The UPA expires in December 2022. KPCo pays a demand charge for the right to receive the power, which is payable even if the power is not taken.

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 SIA and the TA, which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. The FERC also regulates the PCA. See Note 13 - 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 accounting principles generally accepted in the United States of America (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.
- The classification of deferred FICA taxes as taxes accrued rather than as a noncurrent liability.

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, 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 on the statements of cash flows include Cash on the balance sheets with original maturities of three months or less.

Supplementary Information

	2021	2020
For the Years Ended December 31,	**(in thousands)**	
Cash was Paid (Received) for:		
Interest (Net of Capitalized Amounts)	$ 37,378	$ 38,505
Income Taxes (Net of Refunds)	(4,123)	(11,989)

Noncash Acquisitions Under Finance Leases	331	940
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	28,280	19,358

Special Deposits

Special Deposits include funds held by trustees primarily for margin deposits for risk management activities.

Inventory

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

Accounts Receivable

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.

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 12 for additional information.

Allowance for Uncollectible Accounts

Under an affiliated receivables sales arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit. KPCo is charged a fee for each sale that is based on AEP Credit’s financing costs, administrative costs and uncollectible accounts experience from previous purchases of KPCo’s customer accounts receivable. No allowance for uncollectible accounts 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. KPCo terminated selling accounts receivable to AEP Credit in the first quarter of 2022, based on the pending sale to Liberty. As a result of the termination, in the first quarter of 2022, KPCo will record an allowance for uncollectible accounts on its balance sheet for those receivables no longer sold to AEP Credit. For accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For miscellaneous accounts receivable, bad debt expense is recorded based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable, unless specifically identified. In addition to these processes, management contemplates available current information, as well as any reasonable and supportable forecast information, to determine if allowances for uncollectible accounts should be further adjusted in accordance with the accounting guidance for “Credit Losses.” Management’s assessments contemplate expected losses over the life of the accounts receivable.

Concentrations of Credit Risk and Significant Customers

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

Significant Customer of KPCo: Marathon Petroleum Company	**2021**	**2020**
Percentage of Operating Revenues	12 %	12 %
Percentage of Customer Accounts Receivable	45 %	46 %

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. Removal costs accrued are charged to accumulated depreciation.

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 removed from plant-in-service or CWIP and charged to expense.

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.

Valuation of Nonderivative Financial Instruments

The book values of Cash, Special Deposits, Notes Payable to Associated Companies, 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, infrastructure and alternative credit 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”, and are recognized by KPCo in the second quarter of each calendar year following the filing of 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 15 - 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. Purchases under non-trading derivatives 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 and 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 8.

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 and Investment Tax Credits

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 applies the deferral methodology for the recognition of ITC. Deferred ITC is amortized to income tax expense over the life of the asset. Amortization of deferred ITC begins when the asset is placed in-service, except where regulatory commissions reflect ITC in the rate-making process, then amortization begins when the cash tax benefit is recognized.

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's uncertain tax positions are immaterial to the financial statements.

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 discount or premium 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 AEP 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 AEP to provide health and life insurance benefits for retired employees. KPCo accounts for its participation in the AEP sponsored pension and OPEB plans using multiple-employer accounting. See Note 7 - 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	25 %
Fixed Income	59 %
Other Investments	15 %
Cash and Cash Equivalents	1 %

OPEB Plans Assets	Target
Equity	59 %
Fixed Income	40 %
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 all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% and 7% for pension and OPEB investments, respectively, of each 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, 2021 and 2020, the fair value of securities on loan as part of the program was $136.7 million and $177.1 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2021 and 2020.

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. The cash funds are valued each business day and provide daily liquidity.

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-

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).

Disposition of KPCo and KTCo

In October 2021, AEP entered into a Stock Purchase Agreement 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 sale is subject to regulatory approvals from the FERC and KPSC. Clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and clearance from the Committee on Foreign Investment in the United States has been received.
KPCo currently operates and owns a 50% interest in the 1,560 MW coal-fired Mitchell Power Plant (Mitchell Plant) with the remaining 50% owned by WPCo. The Stock Purchase Agreement is further contingent upon the issuance by the KPSC, WVPSC and FERC of orders regarding a new proposed Mitchell Plant Operations and Maintenance Agreement and Mitchell Plant Ownership Agreement between KPCo and WPCo pursuant to which WPCo would replace KPCo as the operator of the Mitchell Plant and KPCo employees at the Mitchell Plant would become employees of WPCo. Under the proposed Ownership Agreement, WPCo is obligated to purchase KPCo's 50% interest in the Mitchell Plant on December 31, 2028 unless KPCo and WPCo have agreed to retire the Mitchell Plant earlier or, absent such agreement, if WPCo elects prior to December 31, 2027 to retire the Mitchell Plant on December 31, 2028. The Ownership Agreement provides that the purchase price for KPCo's 50% ownership interest in the Mitchell Plant will be determined through the mutual agreement of WPCo and KPCo (subject to approval from the KPSC and WVPSC) or through a fair market valuation determination conducted by independent appraisals, with offsets for estimated decommissioning costs and the cost of ELG investments made by WPCo, if KPCo and WPCo are unable to reach agreement as to the purchase price.

In November 2021, AEP made filings with the KPSC, WVPSC, and FERC seeking approval of the new proposed Mitchell Plant Operations and Maintenance Agreement and Mitchell Plant Ownership Agreement. Subsequently, the KPSC and WVPSC intervened in the FERC proceeding and have recommended that FERC dismiss or reject AEP's request, or defer ruling on AEP's request until both the retail commissions have rendered decisions. In February 2022, AEP filed a motion to withdraw its filing with the FERC, noting that AEP intends to re-file its request after the KPSC and WVPSC have reviewed the agreements. In the WVPSC proceeding, intervenor testimony was expected in March 2022 and a hearing is scheduled to occur in April 2022.

In December 2022, Liberty, KPCo and KTCo sought approval from the FERC under Section 203 of the Federal Power Act for the sale. In February 2022 several intervenors in the case filed protests related to whether the sale will negatively impact the wholesale transmission and generation rates of applicants. An order from the FERC is expected on the matter in April 2022.

In January 2022, intervenor testimony was filed with the KPSC, recommending the KPSC either reject the new proposed Mitchell Plant Ownership Agreement or approve the agreement with certain modifications including a revision to the buyout provision that would set WPCo's Mitchell Plant purchase price at the greater of fair market value or net book value. The intervenor testimony also recommends the KPSC reject the proposed Mitchell Plant Operations and Maintenance Agreement, which the testimony stated should be modified to remove references to the Mitchell Plant Ownership Agreement. In February 2022, AEP filed rebuttal testimony with the KPSC opposing the intervenor testimony filed in January 2022. AEP's rebuttal testimony also discusses an alternative proposal to the fair market value provision included in the proposed Mitchell Plant Ownership Agreement. Under the alternative proposal, KPCo's and WPCo's interest in the Mitchell Plant would be divided by unit if the plant is not retired before the end of 2028 and a mutual agreement cannot be reached on a buyout price. Under the alternative proposal, mutual agreement on the buyout price or unit disposition would need to be finalized by May 2025, with a division of plant ownership by unit effective January 1, 2029, unless otherwise agreed. A hearing on the Mitchell Plant agreements was scheduled with the KPSC in March 2022.
In January 2022, KPCo and Liberty filed a joint application requesting the KPSC authorize the transfer of ownership of KPCo to Liberty. In February 2022, certain intervenors filed testimony recommending that the KPSC not approve the transfer of ownership. If, however, the KPSC does approve the transfer, these intervenors recommend that the KPSC require AEP to compensate KPCo customers $578 million for alleged future increased costs and higher rates that the intervenors claim will exist under Liberty's ownership. AEP disagrees with the recommendation and filed rebuttal testimony in March 2022. Intervenors also recommended imposing certain conditions on Liberty, including conditions related to recovering certain costs, inter-company agreement filing requirements, KPCo's capital structure and future generation resource planning processes and analyses. In addition, certain intervenors argue that the commission should not approve the new proposed Mitchell Plant Ownership Agreement and Mitchell Plant Operations and Maintenance Agreement, and that deciding the request to transfer ownership of KPCo should be separated from approval of the Mitchell agreements even though such approval is a condition to the transaction closing. AEP also disagrees with this argument. A hearing was scheduled with the KPSC in March 2022 and a final order is expected in the second quarter of 2022.

The sale is expected to close in the second quarter of 2022 with Liberty acquiring the assets and assuming the liabilities of KPCo and KTCo, excluding pension and other post-retirement benefit plan assets and liabilities. AEP expects to provide customary transition services to Liberty for a period of time after closing of the transaction.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2021 through February 24, 2022, the date that KPCo's 2021 Annual Report was available to be issued, and has updated such evaluation for disclosure purposes through April 6, 2022. 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. There are no new standards expected to have a material impact on KPCo's financial statements.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2021 and 2020. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 - Benefit Plans for additional details.

	Pension and OPEB		
For the Year Ended December 31, 2021	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
		(in thousands)	
Balance in AOCI as of December 31, 2020	$ 3,027	$ (2,149)	$ 878
Change in Fair Value Recognized in AOCI	—	1,008	1,008
Amount of (Gain) Loss Reclassified from AOCI			
Amortization of Prior Service Cost (Credit)	(235)	—	(235)
Amortization of Actuarial (Gains) Losses	62	—	62
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(173)		(173)

Reclassifications from AOCI, before Income Tax (Expense) Benefit	(173)	—	(173)
Income Tax (Expense) Benefit	(36)	—	(36)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(137)	—	(137)
Net Current Period Other Comprehensive Income (Loss)	(137)	1,008	871
Balance in AOCI as of December 31, 2021	$ 2,890	$ (1,141)	$ 1,749

	Pension and OPEB		
For the Year Ended December 31, 2020	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
		(in thousands)	
Balance in AOCI as of December 31, 2019	$ 3,134	$ (2,344)	$ 790
Change in Fair Value Recognized in AOCI	—	195	195
Amount of (Gain) Loss Reclassified from AOCI			
Amortization of Prior Service Cost (Credit)	(228)	—	(228)
Amortization of Actuarial (Gains) Losses	93	—	93
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(135)	—	(135)
Income Tax (Expense) Benefit	(28)	—	(28)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(107)	—	(107)
Net Current Period Other Comprehensive Income (Loss)	(107)	195	88
Balance in AOCI as of December 31, 2020	$ 3,027	$ (2,149)	$ 878

4. 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.

Mitchell Plant

KPCo and WPCo each own a 50% interest in the Mitchell Plant. In December 2020 and February 2021, WPCo and KPCo filed requests with the WVPSC and KPSC, respectively, to obtain the regulatory approvals necessary to implement CCR and ELG compliance plans and seek recovery of the estimated $132 million investment for the Mitchell Plant that would allow the plant to continue operating beyond 2028. Within those requests, WPCo and KPCo also filed a $25 million alternative to implement only the CCR-related investments with the WVPSC and KPSC, respectively, which would allow the Mitchell Plant to continue operating only through 2028.

In July 2021, the KPSC issued an order approving the CCR only alternative and rejecting the full CCR and ELG compliance plan. In August 2021, the WVPSC approved the full CCR and ELG compliance plan for the WPCo share of the Mitchell Plant. In September 2021, WPCo submitted a filing with the WVPSC to reopen the CCR/ELG case that was approved by the WVPSC in August 2021. Due to the rejection by the KPSC of the KPCo share of the ELG investments, WPCo requested the WVPSC consider approving the construction and recovery of all ELG costs at the plant. In October 2021, the WVPSC affirmed its August 2021 order approving the construction of CCR/ELG investments and directed WPCo to proceed with CCR/ELG compliance plans that would allow the plant to continue operating beyond 2028. The WVPSC's order further states WPCo will not share capacity and energy from the plant with KPCo customers if those customers are not paying for ELG compliance costs, or for any new capital investment or continuing operations costs incurred, to allow the plant to operate beyond 2028 or prevent downgrades prior to 2028. The WVPSC also ordered that WPCo will be given the opportunity to recover, from its customers, the new capital and operating costs arising solely from the WVPSC's directive to operate the plant beyond 2028 if the WVPSC finds that the costs are reasonably and prudently incurred. In October and November 2021, intervenors filed petitions for reconsideration at the WVPSC requesting clarification on certain aspects of the order, primarily the jurisdictional allocation of future operating expenses and plant costs.

In November 2021, AEP made filings with the KPSC, WVPSC and FERC seeking approval for a new proposed Mitchell Plant Operations and Maintenance Agreement and Mitchell Plant Ownership Agreement between KPCo and WPCo pursuant to which WPCo would replace KPCo as the operator of the Mitchell Plant. Subsequently, the KPSC and WVPSC intervened in the FERC proceeding and have recommended that the FERC dismiss or reject AEP's request, or defer ruling on AEP's request until both the retail commissions have rendered decisions. In February 2022, AEP filed a motion to withdraw its filing with the FERC, noting that AEP intends to re-file its request after the KPSC and WVPSC have reviewed the agreements. In the WVPSC proceeding, intervenor testimony was expected in March 2022 and a hearing is scheduled to occur in April 2022.
In January 2022, intervenor testimony was filed with the KPSC, recommending the KPSC either reject the new proposed Mitchell Plant Ownership Agreement or approve the agreement with certain modifications including a revision to the buyout provision that would set WPCo's Mitchell Plant purchase price at the greater of fair market value or net book value. The intervenor testimony also recommends the KPSC reject the proposed Mitchell Plant Operations and Maintenance Agreement, which the testimony stated should be modified to remove references to the Mitchell Plant Ownership Agreement. In February 2022, AEP filed rebuttal testimony with the KPSC opposing the intervenor testimony filed in January 2022. AEP's rebuttal testimony also discusses an alternative proposal to the fair market value provision included in the proposed Mitchell Plant Ownership Agreement. Under the alternative proposal, KPCo's and WPCo's interest in the Mitchell Plant would be divided by unit if the plant is not retired before the end of 2028 and a mutual agreement cannot be reached on a buyout price. Under the alternative proposal, mutual agreement on the buyout price or unit disposition would need to be finalized by May 2025, with a division of plant ownership by unit effective January 1, 2029, unless otherwise agreed. A hearing on the Mitchell Plant agreements was scheduled with the KPSC in March 2022. See "Disposition of KPCo and KTCo" section of Note 1 for additional information.

As of December 31, 2021, KPCo's share of the Mitchell Plant's ELG investment balance in CWIP was $3.3 million. As of December 31, 2021, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $586.1 million.

If any of the ELG costs are not approved for recovery and/or the retirement date of the Mitchell Plant is accelerated to 2028 without commensurate cost recovery, it would reduce future net income and cash flows and impact financial condition.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31,		Remaining
Regulatory Assets:	**2021**	**2020**	**Recovery Period**
	(in thousands)		
Regulatory assets pending final regulatory approval:			

	2021	2020	
<u>Regulatory Assets Currently Earning a Return</u>			
Kentucky Deferred Purchased Power Expenses	$ 47,528	$ 41,267	
Total Regulatory Assets Currently Earning a Return	47,528	41,267	
<u>Regulatory Assets Currently Not Earning a Return</u>			
Storm Related Costs (a)	56,506	10,708	
Other Regulatory Assets Pending Final Regulatory Approval	893	2,065	
Total Regulatory Assets Currently Not Earning a Return	57,399	12,773	
Total Regulatory Assets Pending Final Regulatory Approval	104,927	54,040	
Regulatory assets approved for recovery:			
<u>Regulatory Assets Currently Earning a Return</u>			
Plant Retirement Costs	193,229	203,967	19 years
Plant Retirement Costs - Asset Retirement Obligation Costs	109,577	107,136	19 years
Plant Retirement Costs - Materials and Supplies	3,016	3,016	19 years
Other Regulatory Assets Approved for Recovery	928	926	various
Total Regulatory Assets Currently Earning a Return	306,750	315,045	
<u>Regulatory Assets Currently Not Earning a Return</u>			
Income Tax Assets Subject to Flow Through	128,784	155,453	22 years
Fuel and Purchased Power Rider	28,727	22,470	2 years
Pension and OPEB Funded Status	12,236	29,050	12 years
Under-recovered Fuel Costs	8,216	—	1 year
Environmental Costs	5,920	6,146	2 years
Plant Retirement Costs - Asset Retirement Obligation Costs	4,721	9,917	19 years
Postemployment Benefits	3,410	3,437	3 years
Storm Related Costs	2,167	4,233	2 years
Other Regulatory Assets Approved for Recovery	7,231	5,407	various
Total Regulatory Assets Currently Not Earning a Return	201,412	236,113	
Total Regulatory Assets Approved for Recovery	508,162	551,158	
Total FERC Account 182.3 Regulatory Assets	$ 613,089	$ 605,198	

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

Regulatory Liabilities:	**December 31, 2021**	**2020**	**Remaining Refund Period**
	(in thousands)		
Regulatory liabilities pending final regulatory determination:			
<u>Regulatory Liabilities Currently Not Paying a Return</u>			
Other Regulatory Liabilities Pending Final Regulatory Determination	$ 2,098	$ 1,332	
Total Regulatory Liabilities Pending Final Regulatory Determination	2,098	1,332	
Regulatory liabilities approved for payment:			
<u>Regulatory Liabilities Currently Not Paying a Return</u>			
PJM Transmission Enhancement Refund	2,644	2,636	4 years
Over-recovered Fuel Costs	—	313	
Other Regulatory Liabilities Approved for Payment	4,758	958	various
Total Regulatory Liabilities Currently Not Paying a Return	7,402	3,907	
<u>Income Tax Related Regulatory Liabilities (a)</u>			
Excess ADIT Associated with Certain Depreciable Property	120,620	125,876	(b)
Excess ADIT that is Not Subject to Rate Normalization Requirements	81,377	118,165	2 years
Total Income Tax Related Regulatory Liabilities	201,997	244,041	
Total Regulatory Liabilities Approved for Payment	209,399	247,948	
Total FERC Account 254 Regulatory Liabilities	$ 211,497	$ 249,280	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Refunded using Average Rate Assumption Method.

6. 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, 2021:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)(b)	$ 57,981	$ 48,538	$ 11,985	$ 26,466	$ 144,970
Energy and Capacity Purchase Contracts	58,141	—	—	—	58,141
Total	$ 116,122	$ 48,538	$ 11,985	$ 26,466	$ 203,111

(a) Represents contractual commitments to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel.
(b) In the first quarter of 2022, KPCo entered into new fuel purchase contracts related to coal procurement. The new commitments were as follows: $14.1 million in less than 1 year, $45.8 million in 2-3 years and $31.9 million in 4-5 years. These commitments are not included in the tables above.

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, 2021, 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.

Lease Obligations

KPCo leases certain equipment under master lease agreements. See "Master Lease Agreements" section of Note 11 for additional information.

CONTINGENCIES

Insurance and Potential Losses

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

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

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, 2021, 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, 2021, management's estimates do not anticipate material clean-up costs for the identified site.

Claims Challenging Transition of American Electric Power System Retirement Plan to Cash Balance Formula

Four participants in The American Electric Power System Retirement Plan (the Plan) filed a class action complaint in December 2021 in the U.S. District Court for the Southern District of Ohio against AEPSC and the Plan. When the Plan's benefit formula was changed in the year 2000, AEP provided a special provision for employees hired before January 1, 2001, allowing them to continue benefit accruals under the then benefit formula for a full 10 years alongside of the new cash balance benefit formula then being implemented. Employees who were hired on or after January 1, 2001 accrued benefits only under the new cash balance benefit formula. The Plaintiffs assert a number of claims on behalf of themselves and the purported class, including that: (a) the Plan violates the requirements under the Employee Retirement Income Security Act (ERISA) intended to preclude back-loading the accrual of benefits to the end of a participant's career, (b) the Plan violates the age discrimination prohibitions of ERISA and the Age Discrimination in Employment Act and (c) AEP failed to provide required notice regarding the changes to the Plan. Among other relief, the Complaint seeks reformation of the Plan to provide additional benefits and the recovery of plan benefits for former employees under such reformed plan. The Plaintiffs previously had submitted claims for additional plan benefits to AEP, which were denied. On February 15, 2022, AEPSC and the Plan filed a motion to dismiss the complaint for failure to state a claim. AEP will continue to defend against the claims. Management is unable to determine a range of potential losses that is reasonably possible of occurring.

7. 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 AEP 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 AEP 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	2021	2020	2021	2020
Discount Rate	2.90 %	2.50 %	2.90 %	2.55 %
Interest Crediting Rate	4.00 %	4.00 %	NA	NA
Rate of Compensation Increase	4.90 % (a)	4.80 % (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 2021, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with an average increase of 4.9%.

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	2021	2020	2021	2020
Discount Rate	2.50 %	3.25 %	2.55 %	3.30 %
Interest Crediting Rate	4.00 %	4.00 %	NA	NA
Expected Return on Plan Assets	4.75 %	5.75 %	4.75 %	5.50 %
Rate of Compensation Increase	4.90 % (a)	4.80 % (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	2021	2020
Initial	6.25 %	6.50 %
Ultimate	4.50 %	4.50 %
Year Ultimate Reached	2029	2029

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. The plans are monitored to control security diversification and ensure compliance with the investment policy. As of December 31, 2021, 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, 2021, the pension plans had an actuarial gain primarily due to an increase in the discount rate, partially offset by less favorable demographic experience than expected, resulting from the updated census information as of January 1, 2021. For the year ended December 31, 2021, the OPEB plans had an actuarial gain primarily due to an increase in the discount rate and an update of the projected reimbursements from the Employer Group Waiver Program under Medicare Part D. For the year ended

December 31, 2020, the pension plans had an actuarial loss primarily due to a decrease in the discount rate, partially offset by a decrease in the assumed rate used to convert account balances to annuities. For the year ended December 31, 2020, the OPEB plans had an actuarial loss primarily due to a decrease in the discount rate and an update to the health care trend assumption, partially offset by updated projected per capita claims costs due to rate negotiations for Medicare advantage premium rates. The following table provides a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		OPEB	
	2021	2020	2021	2020
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1,	$ 198,433	$ 188,085	$ 45,058	$ 45,550
Service Cost	3,477	3,119	283	299
Interest Cost	4,840	5,971	1,096	1,493
Actuarial (Gain) Loss	(9,831)	13,995	(5,851)	2,110
Plan Amendments	—	—	(216)	(470)
Benefit Payments	(12,720)	(12,737)	(5,156)	(5,514)
Participant Contributions	—	—	1,708	1,579
Medicare Subsidy	—	—	10	11
Benefit Obligation as of December 31,	$ 184,199	$ 198,433	$ 36,932	$ 45,058
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 208,552	$ 186,407	$ 75,920	$ 68,972
Actual Gain on Plan Assets	8,095	32,107	4,960	10,882
Company Contributions	5	2,775	1	1
Participant Contributions	—	—	1,708	1,579
Benefit Payments	(12,720)	(12,737)	(5,156)	(5,514)
Fair Value of Plan Assets as of December 31,	$ 203,932	$ 208,552	$ 77,433	$ 75,920
Funded Status as of December 31,	$ 19,733	$ 10,119	$ 40,501	$ 30,862

Amounts Recognized on the Balance Sheets

	Pension Plans		OPEB	
	December 31,			
	2021	2020	2021	2020
	(in thousands)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 19,832	$ 10,200	$ 40,501	$ 30,862
Other Current Liabilities – Accrued Short-term Benefit Liability	(3)	(1)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(96)	(80)	—	—
Funded Status	$ 19,733	$ 10,119	$ 40,501	$ 30,862

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

The following table shows the components of the plans included in Other Regulatory Assets, Accumulated Deferred Income Taxes and AOCI:

	Pension Plans		OPEB	
	December 31,			
	2021	2020	2021	2020
Components	(in thousands)			
Net Actuarial (Gain) Loss	$ 22,630	$ 35,498	$ (6,622)	$ 710
Prior Service Credit	—	—	(5,987)	(8,270)
Recorded as				
Regulatory Assets	$ 21,923	$ 34,593	$ (9,687)	$ (5,543)
Deferred Income Taxes	148	190	(614)	(424)
Net of Tax AOCI	559	715	(2,308)	(1,593)

Components of the change in amounts included in Other Regulatory Assets, Accumulated Deferred Income Taxes and AOCI were as follows:

	Pension Plans		OPEB	
	2021	2020	2021	2020
Components	(in thousands)			
Actuarial Gain During the Year	$ (9,345)	$ (8,220)	$ (7,332)	$ (5,034)
Amortization of Actuarial Loss	(3,523)	(3,292)	—	(239)
Prior Service Credit	—	—	(216)	(461)
Amortization of Prior Service Credit	—	—	2,499	2,452
Change for the Year Ended December 31,	$ (12,868)	$ (11,512)	$ (5,049)	$ (3,282)

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,			
2021	2020	2021	2020
3.8 %	3.8 %	3.8 %	3.9 %

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2021:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
	(in millions)					
Equities (a):						
Domestic	$ 388.9	$ —	$ —	$ —	$ 388.9	7.2 %
International	465.7	—	—	—	465.7	8.7 %
Common Collective Trusts (c)	—	—	—	463.9	463.9	8.7 %
Subtotal – Equities	854.6	—	—	463.9	1,318.5	24.6 %
Fixed Income (a):						
United States Government and Agency Securities	0.1	1,557.6	—	—	1,557.7	29.1 %
Corporate Debt	—	1,295.9	—	—	1,295.9	24.2 %
Foreign Debt	—	259.4	—	—	259.4	4.8 %
State and Local Government	—	57.1	—	—	57.1	1.1 %
Other – Asset Backed	—	1.3	—	—	1.3	— %
Subtotal – Fixed Income	0.1	3,171.3	—	—	3,171.4	59.2 %
Infrastructure (c)	—	—	—	92.1	92.1	1.7 %
Real Estate (c)	—	—	—	232.6	232.6	4.4 %
Alternative Investments (c)	—	—	—	448.8	448.8	8.4 %
Cash and Cash Equivalents (c)	—	64.3	—	53.4	117.7	2.2 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(28.2)	(28.2)	(0.5)%
Total	$ 854.7	$ 3,235.6	$ —	$ 1,262.6	$ 5,352.9	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 primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2021:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
	(in millions)					
Equities:						
Domestic	$ 474.0	$ —	$ —	$ —	$ 474.0	23.2 %
International	296.3	—	—	—	296.3	14.5 %
Common Collective Trusts (b)	—	—	—	265.0	265.0	13.0 %
Subtotal – Equities	770.3	—	—	265.0	1,035.3	50.7 %
Fixed Income:						
Common Collective Trust Debt (b)	—	—	—	167.7	167.7	8.2 %
United States Government and Agency Securities	—	222.4	—	—	222.4	10.9 %
Corporate Debt	—	233.2	—	—	233.2	11.4 %
Foreign Debt	—	39.8	—	—	39.8	2.0 %
State and Local Government	91.9	13.6	—	—	105.5	5.1 %
Subtotal – Fixed Income	91.9	509.0	—	167.7	768.6	37.6 %
Trust Owned Life Insurance:						
International Equities	—	23.4	—	—	23.4	1.1 %
United States Bonds	—	171.3	—	—	171.3	8.4 %
Subtotal – Trust Owned Life Insurance	—	194.7	—	—	194.7	9.5 %
Cash and Cash Equivalents (b)	33.0	—	—	6.7	39.7	1.9 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	6.0	6.0	0.3 %
Total	$ 895.2	$ 703.7	$ —	$ 445.4	$ 2,044.3	100.0 %

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

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2020:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
	(in millions)					

Equities (a):						
Domestic	$ 542.3	$ —	$ —	$ —	$ 542.3	9.7 %
International	676.3	—	—	—	676.3	12.2 %
Common Collective Trusts (c)	—	—	—	650.0	650.0	11.7 %
Subtotal – Equities	1,218.6	—	—	650.0	1,868.6	33.6 %
Fixed Income (a):						
United States Government and Agency Securities	(1.4)	1,134.1	—	—	1,132.7	20.4 %
Corporate Debt	—	1,425.0	—	—	1,425.0	25.6 %
Foreign Debt	—	214.0	—	—	214.0	3.9 %
State and Local Government	—	56.0	—	—	56.0	1.0 %
Other – Asset Backed	—	0.8	—	—	0.8	— %
Subtotal – Fixed Income	(1.4)	2,829.9	—	—	2,828.5	50.9 %
Infrastructure (c)	—	—	—	91.1	91.1	1.6 %
Real Estate (c)	—	—	—	231.6	231.6	4.2 %
Alternative Investments (c)	—	—	—	431.8	431.8	7.8 %
Cash and Cash Equivalents (c)	—	49.3	—	58.2	107.5	1.9 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(2.5)	(2.5)	— %
Total	$ 1,217.2	$ 2,879.2	$ —	$ 1,460.2	$ 5,556.6	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 primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2020:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 399.9	$ —	$ —	$ —	$ 399.9	20.6%
International	290.7	—	—	—	290.7	14.9%
Common Collective Trusts (b)	—	—	—	264.7	264.7	13.6%
Subtotal – Equities	690.6	—	—	264.7	955.3	49.1%
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	186.4	186.4	9.6%
United States Government and Agency Securities	(0.2)	199.7	—	—	199.5	10.2%
Corporate Debt	—	248.7	—	—	248.7	12.8%
Foreign Debt	—	34.9	—	—	34.9	1.8%
State and Local Government	73.9	13.1	—	—	87.0	4.5%
Subtotal – Fixed Income	73.7	496.4	—	186.4	756.5	38.9%
Trust Owned Life Insurance:						
International Equities	—	64.8	—	—	64.8	3.3%
United States Bonds	—	135.9	—	—	135.9	7.0%
Subtotal – Trust Owned Life Insurance	—	200.7	—	—	200.7	10.3%
Cash and Cash Equivalents (b)	26.3	—	—	5.7	32.0	1.6%
Other – Pending Transactions and Accrued Income (a)	—	—	—	2.2	2.2	0.1%
Total	$ 790.6	$ 697.1	$ —	$ 459.0	$ 1,946.7	100.0%

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

Accumulated Benefit Obligation

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

	December 31, 2021	December 31, 2020
	(in thousands)	
Qualified Pension Plan	$ 177,132	$ 191,045
Nonqualified Pension Plan	34	19
Total Accumulated Benefit Obligation	$ 177,166	$ 191,064

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,

	December 31,	
	2021	2020
	(in thousands)	
Projected Benefit Obligation	$ 98	$ 81
Fair Value of Plan Assets	—	—
Underfunded Projected Benefit Obligation	$ (98)	$ (81)

Accumulated Benefit Obligation

	Underfunded Pension Plans	
	December 31,	
	2021	2020
	(in thousands)	
Accumulated Benefit Obligation	$ 34	$ 19
Fair Value of Plan Assets	—	—
Underfunded Accumulated Benefit Obligation	$ (34)	$ (19)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the Pension and OPEB plans of $3.5 million and $51 thousand, respectively, during 2022. 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)	
2022	$ 12,638	$ 5,002
2023	13,228	4,550
2024	12,520	4,530
2025	12,409	4,459
2026	13,188	4,362
Years 2027 to 2031, in Total	59,324	20,286

Components of Net Periodic Benefit Cost

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

	Pension Plans		OPEB	
	Years Ended December 31,			
	2021	2020	2021	2020
	(in thousands)			
Service Cost	$ 3,477	$ 3,119	$ 283	$ 299
Interest Cost	4,840	5,971	1,096	1,493
Expected Return on Plan Assets	(8,583)	(9,891)	(3,479)	(3,763)
Amortization of Prior Service Credit	—	—	(2,499)	(2,452)
Amortization of Net Actuarial Loss	3,523	3,292	—	239
Net Periodic Benefit Cost (Credit)	3,257	2,491	(4,599)	(4,184)
Capitalized Portion	(1,582)	(1,371)	(129)	(131)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 1,675	$ 1,120	$ (4,728)	$ (4,315)

American Electric Power System Retirement Savings Plan

KPCo participates in an AEP 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 $2.3 million in 2021 and $2.3 million in 2020.

8. 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, 2021	December 31, 2020	Unit of Measure
	(in thousands)		
Commodity:			
Power	6,927	8,249	MWhs
Heating Oil and Gasoline	305	270	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. For the December 31, 2021 and 2020 balance sheets, KPCo netted $95 thousand and $96 thousand, respectively, of cash collateral received from third-parties against short-term and long-term risk management assets and $0 and $0, respectively, of cash collateral paid to third-parties against short-term and long-term risk management liabilities.
The following tables represent the gross fair value of KPCo’s derivative activity on the balance sheets:

Balance Sheet Location	December 31, 2021 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in thousands)		
Derivative Instrument Assets	$ 7,534	$ (1,548)	$ 5,986
Long-Term Portion of Derivative Instrument Assets	46	(46)	—
Derivative Instrument Liabilities	$ 1,504	$ (1,453)	$ 51
Long-Term Portion of Derivative Instrument Liabilities	46	(46)	—

Balance Sheet Location	December 31, 2020 Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in thousands)		
Derivative Instrument Assets	$ 6,890	$ (3,715)	$ 3,175
Long-Term Portion of Derivative Instrument Assets	139	(116)	23
Derivative Instrument Liabilities	$ 3,851	$ (3,619)	$ 232
Long-Term Portion of Derivative Instrument Liabilities	105	(86)	19

(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 amount of gain (loss) recognized on risk management contracts:

Location of Gain (Loss)	Years Ended December 31, 2021	2020
	(in thousands)	
Operating Revenues	$ (12)	$ 182
Operation Expenses	208	42
Maintenance Expenses	116	(98)
Other Regulatory Assets (a)	(1,077)	437
Other Regulatory Liabilities (a)	11,192	7,642
Total Gain on Risk Management Contracts	$ 10,427	$ 8,205

(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 2021 and 2020 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 2021 and 2020, 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, 2021 and 2020.

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, 2021, 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, surety bonds 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, 2021 and 2020, KPCo did not have derivative contracts with collateral triggering events in a net liability position.
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. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements:

	December 31, 2021	2020
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 89	$ 154

Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ [illegible]	$ [illegible]
Additional Settlement Liability if Cross Default Provision is Triggered	51	16

9. 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,			
2021		2020	
Book Value	Fair Value	Book Value	Fair Value
(in thousands)			
$ 1,105,000	$ 1,224,664	$ 995,000	$ 1,166,298

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, 2021

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 1,096	$ 6,439	$ (1,549)	$ 5,986
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 937	$ 568	$ (1,454)	$ 51

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2020

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 3,669	$ 3,204	$ (3,698)	$ 3,175
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 3,655	$ 179	$ (3,602)	$ 232

(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, 2021	Derivative Instrument Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2020	$ 3,025
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	1,858
Settlements	(4,950)
Transfers out of Level 3 (c)	8
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	5,930
Balance as of December 31, 2021	$ 5,871

Year Ended December 31, 2020	Derivative Instrument Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2019	$ 5,702
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	4,084
Settlements	(9,900)
Transfers out of Level 3 (c)	130
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	3,009
Balance as of December 31, 2020	$ 3,025

(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) Transfers are recognized based on their value at the beginning if the period that the transfer occurred.
(d) 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, 2021 and 2020:

Significant Unobservable Inputs
December 31, 2021

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in thousands)						
Energy Contracts	$ —	$ 51	Discounted Cash Flow	Forward Market Price	$ 32.20	$ 56.54	$ 44.77
FTRs	6,439	517	Discounted Cash Flow	Forward Market Price	(1.44)	22.19	1.74
Total	$ 6,439	$ 568					

Significant Unobservable Inputs
December 31, 2020

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in thousands)						
Energy Contracts	$ 190	$ 121	Discounted Cash Flow	Forward Market Price	$ 10.84	$ 41.09	$ 25.08
FTRs	3,014	58	Discounted Cash Flow	Forward Market Price	0.17	4.18	1.03
Total	$ 3,204	$ 179					

(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, 2021 and 2020:

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)

10. INCOME TAXES

Income Tax Benefit

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

	Years Ended December 31, 2021	2020
	(in thousands)	
Federal:		
Current	$ (1,302)	$ (8,640)
Deferred	(23,931)	4,696
Total Federal	(25,233)	(3,944)
State and Local:		
Current	(1,668)	(770)
Deferred	(578)	671
Total State and Local	(2,246)	(99)
Income Tax Benefit	$ (27,479)	$ (4,043)

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, 2021	2020
	(in thousands)	
Net Income	$ 50,150	$ 41,017
Income Tax Benefit	(27,479)	(4,043)
Pretax Income	$ 22,671	$ 36,974
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 4,761	$ 7,765
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Depreciation	1,891	1,738
State and Local Income Taxes, Net	(2,871)	(2,542)
Removal Costs	(2,154)	(1,885)

Tax Adjustments (a)	3,098	—
Tax Reform Excess ADIT Reversal	(31,174)	(8,293)
Federal Return to Provision Adjustment	(952)	(114)
Other	(78)	(712)
Income Tax Benefit	$ (27,479)	$ (4,043)
Effective Income Tax Rate	(121.2) %	(10.9) %

(a) Represents the correction of an out of period adjustment related to Deferred Income Taxes and Income Tax Expense (Benefit). Management concluded the misstatement and subsequent correction was not material to prior or current period financial statements.

Net Deferred Tax Liability

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

	December 31, 2021	December 31, 2020
	(in thousands)	
Deferred Tax Assets	$ 94,062	$ 101,993
Deferred Tax Liabilities	(531,214)	(548,047)
Net Deferred Tax Liabilities	$ (437,152)	$ (446,054)
Property Related Temporary Differences	$ (310,721)	$ (300,947)
Amounts Due to Customers for Future Income Taxes	51,754	62,526
Deferred State Income Taxes	(92,617)	(120,361)
Net Operating Loss Carryforward	17,475	7,795
Regulatory Assets	(101,155)	(92,015)
All Other, Net	(1,888)	(3,052)
Net Deferred Tax Liabilities	$ (437,152)	$ (446,054)

AEP System Tax Allocation Agreement

KPCo and other AEP subsidiaries join in the filing of a consolidated federal income tax return. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax loss of the parent company (Parent Company Loss Benefit) to the AEP System subsidiaries with taxable income reducing their current tax expense proportionately. The consolidated net operating loss (NOL) of the AEP System is allocated to each company in the consolidated group with taxable losses. 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.

Federal Income Tax Audit Status

The statute of limitations for the IRS to examine KPCo and other AEP subsidiaries originally filed federal return has expired for tax years 2016 and earlier. In the third quarter of 2019, KPCo and other AEP subsidiaries elected to amend the 2014 through 2017 federal returns. In the first quarter of 2020, the IRS notified KPCo and other AEP subsidiaries that it was beginning an examination of these amended returns, including the net operating loss carryback to 2015 that originated in the 2017 return. As of December 31, 2021, the IRS has not issued any proposed adjustments and the IRS is limited in their proposed adjustments to the amount KPCo and other AEP subsidiaries claimed on the amended returns. KPCo has agreed to extend the statute of limitations on the 2017 tax return to December 31, 2022 to allow time for the audit to be completed and the Congressional Joint Committee on Taxation to approve the associated refund claim.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns, and KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. The Registrants are no longer subject to state or local examinations by tax authorities for years before 2012. 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 $222 million and $159 million in 2021 and 2020, respectively. As a result, KPCo recognized deferred state income tax benefits in 2021 and 2020 of $11 million and $10 million, respectively. Management anticipates future taxable income will be sufficient to realize the state net income tax operating loss tax benefits before the state carryforward expires for Kentucky in 2035.

11. LEASES

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

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

Operating and Finance lease rental 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, 2021	2020
	(in thousands)	
Operating Lease Cost	$ 3,100	$ 2,660

Finance Lease Cost:				
Amortization of Finance Leases		920		808
Interest on Finance Leases		125		138
Total Lease Rental Costs (a)	$	4,145	$	3,606

(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,			
	2021	2020	2021	2020
Operating Leases	6.05	6.45	3.33 %	3.44 %
Finance Leases	4.68	5.00	4.00 %	4.08 %

	Years Ended December 31,			
	2021		2020	
	(in thousands)			
Cash Paid for Amounts Included in the Measurement of Lease Liabilities				
Operating Cash Flows Used for Operating Leases	$	3,089	$	2,660
Operating Cash Flows Used for Finance Leases		1,045		946
Non-cash Acquisitions Under Operating Leases	$	1,261	$	3,915

The following tables show the property, plant and equipment under finance leases and operating leases and related obligations recorded on KPCo's balance sheets.

	December 31,			
	2021		2020	
	(in thousands)			
Property, Plant and Equipment Under Finance Leases				
Utility Plant (a)	$	2,855	$	3,443
Obligations Under Finance Leases				
Noncurrent	$	2,064	$	2,577
Current		791		866
Total Obligations Under Finance Leases	$	2,855	$	3,443

(a) Includes $2.6 million and $2.2 million of accumulated provision for depreciation and amortization for the years ended December 31, 2021 and 2020, respectively.

	December 31,			
	2021		2020	
	(in thousands)			
Property, Plant and Equipment Under Operating Leases				
Utility Plant (a)	$	10,755	$	11,935
Obligations Under Operating Leases				
Noncurrent	$	8,614	$	9,672
Current		2,173		2,296
Total Obligations Under Operating Leases	$	10,787	$	11,968

(a) Includes $4.5 million and $3.2 million of accumulated provision for depreciation and amortization for the years ended December 31, 2021 and 2020, respectively.

Future minimum lease payments consisted of the following as of December 31, 2021:

Future Minimum Lease Payments	Finance Leases		Operating Leases	
	(in thousands)			
2022	$	890	$	2,507
2023		715		2,247
2024		598		2,015
2025		331		1,643
2026		245		1,195
After 2026		365		2,332
Total Future Minimum Lease Payments		3,144		11,939
Less: Imputed Interest		289		1,152
Estimated Present Value of Future Minimum Lease Payments	$	2,855	$	10,787

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, 2021, the maximum potential loss for these lease agreements was $1.7 million 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, 2021 and December 31, 2020, respectively.

12. 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, 2021	Interest Rate Ranges as of December 31, 2021	Interest Rate Ranges as of December 31, 2020	Outstanding as of December 31, 2021	Outstanding as of December 31, 2020
					(in thousands)	
Senior Unsecured Notes	2021-2047	4.54%	3.13%-8.13%	3.13%-8.13%	$ 690,000	$ 730,000
Pollution Control Bonds	2023 (a)	2.35%	2.35%	2.35%	65,000	65,000
Other Long-term Debt	2022-2023	1.01%	0.76%-1.61%	0.81%-1.60%	350,000	200,000
Total Long-Term Debt					$ 1,105,000	$ 995,000

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

As of December 31, 2021, outstanding long-term debt was payable as follows:

	2022	2023	2024	2025	2026	After 2026	Total
				(in thousands)			
Principal Amount	$ 200,000	$ 215,000	$ 65,000	$ —	$ 200,000	$ 425,000	$ 1,105,000
Total Long-Term Debt							$ 1,105,000

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 restriction that prohibits the payment of dividends out of capital accounts without regulatory approval; payment of dividends is allowed out of retained earnings only.

KPCo has credit agreements that contain a covenant that limit its debt to capitalization ratio to 67.5%. As of December 31, 2021, 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 Federal Power Act. As of December 31, 2021, 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 $578.3 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, 2021, there were no restrictions on KPCo's ability to pay dividends out of retained earnings.

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, 2021 and 2020 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)			
2021	$ 121,608	$ 43,730	$ 46,522	$ 22,427	$ 47,895	$ 180,000
2020	126,742	6,572	50,064	5,020	65,647	180,000

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
2021	0.48 %	0.02 %	0.34 %	0.03 %	0.31 %	0.33 %
2020	2.70 %	0.27 %	2.08 %	1.80 %	1.18 %	1.81 %

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 advances 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, 2021	Years Ended December 31, 2020
(in thousands)	

	(in thousands)			
Interest Expense	$	166	$	676
Interest Income		6		48

Securitized Accounts Receivables – AEP Credit

Under an affiliated receivables sales arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued utility revenue balances to AEP Credit. KPCo is charged a fee for each sale that is based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience from previous purchases of KPCo's customer accounts receivable. No allowance for uncollectible accounts 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 Deductions on KPCo's statements of income. KPCo manages and services its accounts receivable sold.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and was amended in September 2021 to include a $125 million and a $625 million facility, which expire in September 2023 and 2024, respectively. As of December 31, 2021, KPCo was in compliance with all requirements under the agreement.

KPCo's amounts of accounts receivable and accrued utility revenues under the sale of receivables agreement were $53.3 million and $54.8 million as of December 31, 2021 and 2020, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $1.9 million and $7.1 million for the years ended December 31, 2021 and 2020, respectively. In 2020, an increase in allowance for doubtful accounts was recognized by AEP Credit in response to the anticipated impact of COVID-19 on the collectability of accounts receivable, which caused an increase in fees paid by KPCo. In 2021, due to higher than expected collections of accounts receivables, allowance for doubtful accounts was adjusted resulting in the issuance of credits to offset the higher fees previously paid and to lower subsequent fees paid. KPCo terminated selling accounts receivable to AEP Credit in the first quarter of 2022, based on the pending sale to Liberty. As a result of the termination, in the first quarter of 2022, KPCo will record an allowance for uncollectible accounts on its balance sheet for those receivables no longer sold to AEP Credit.

KPCo's proceeds on the sale of receivables to AEP Credit were $595 million and $501.9 million for the years ended December 31, 2021 and 2020, respectively.

13. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 10 in addition to "Corporate Borrowing Program – AEP System" and "Securitized Accounts Receivables – AEP Credit" sections of Note 12.

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.

System Integration Agreement

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity. Margins resulting from trading and marketing activities originating in PJM generally accrue to the benefit of APCo, I&M, KPCo and WPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the equity positions of these companies.

Affiliated Revenues and Purchases

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	**2021**		**2020**	
	(in thousands)			
Sales under Interconnection Agreement	$	—	$	149
Auction Sales to OPCo (a)		—		975
Transmission Agreement Sales		8,991		9,367
Other Revenues		1,551		1,506
Total Affiliated Revenues	$	10,542	$	11,997

(a) Refer to the Ohio Auctions section below for further information regarding this amount.

The table below shows the purchased power expenses incurred for purchases from affiliates as follows:

	Years Ended December 31,	
Related Party Purchases	**2021**	**2020**
	(in thousands)	
Direct Purchases from AEGCo (a)	$ 93,365	$ 74,055
Total Affiliated Purchases	$ 93,365	$ 74,055

(a) Refer to the "Unit Power Agreements" section below for further information regarding this amount.

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, 2021 and 2020 were $57.1 million and $48.1 million, respectively, and were recorded in Operation Expenses on KPCo's statements of income.

Ohio Auctions

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. Certain affiliated entities, including KPCo, participate in the auction process and have been awarded tranches of OPCo's SSO load. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions.

Unit Power Agreements

UPA between AEGCo and I&M

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. Subsequently, I&M assigns 30% of the power to KPCo. 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 its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement 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).

UPA between AEGCo and KPCo

Pursuant to an assignment between I&M and KPCo and a UPA between AEGCo and KPCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo UPA ends in December 2022.

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. KPCo recorded expenses of $3.1 million and $3.2 million in 2021 and 2020, respectively, for urea transloading provided by I&M. These expenses were recorded as Operation Expenses.

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 $973 thousand and $854 thousand for the years ended December 31, 2021 and 2020, 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. The table below shows the sales and purchases, recorded in Utility Plant on the balance sheets at net book value, as follows:

	Years Ended December 31,	
	2021	**2020**
	(in thousands)	
Sales	$ 431	$ 825
Purchases	3,995	1,464

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.

AEPSC

AEPSC provides certain managerial and professional services to AEP's subsidiaries. The costs of the services are based on a direct charge or on a prorated basis and billed to KPCo at AEPSC's cost. AEPSC and its billings are subject to regulation by the FERC. KPCo's total billings from AEPSC for the years ended December 31, 2021 and 2020 were $75.2 million and $70.4 million, respectively.

14. <u>PROPERTY, PLANT AND EQUIPMENT</u>

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 2021 and 2020.

Year	Steam	Transmission	Distribution	General
		(in percentages)		
2021	3.0	2.6	3.4	9.5

2020	2.8	2.6	3.4	9.5

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

Asset Retirement Obligations (ARO)

KPCo records ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for the retirement of ash disposal facilities and asbestos removal. 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 its facilities indefinitely. The retirement obligation would only be recognized if and when KPCo abandons or ceases the use of specific easements, which is not expected.

The following is a reconciliation of the 2021 and 2020 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)			
2021	$ 24,565	$ 968	$ —	$ (3,227)	$ (4,609)	$ 17,697
2020	43,588	1,691	77	(20,426)	(365)	24,565

(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, 2021					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,049,434	$ 12,040	$ 493,124
KPCo's Share as of December 31, 2020					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,047,564	$ 40,024	$ 465,764

(a) Operated by KPCo. In November 2021, AEP made filings seeking approval for a new proposed Mitchell Plant Operations and Maintenance Agreement and Mitchell Plant Ownership Agreement between KPCo and WPCo pursuant to which WPCo would replace KPCo as the operator of the Mitchell Plant. See Note 4 - Rate Matters for additional information.

15. 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, 2021	2020
	(in thousands)	
Retail Revenues:		
Residential Revenues	$ 282,900	$ 236,325
Commercial Revenues	160,183	138,813
Industrial Revenues	142,217	121,907
Other Retail Revenues	2,029	1,889
Total Retail Revenues	587,329	498,934
Wholesale Revenues:		
Generation Revenues (a)	43,070	17,667
Transmission Revenues (b)	22,052	22,864
Total Wholesale Revenues	65,122	40,531
Other Revenues from Contracts with Customers (a)	8,277	12,106
Total Revenues from Contracts with Customers	660,728	551,571
Other Revenues:		
Alternative Revenues (a)	(1,180)	1,185
Total Other Revenues	(1,180)	1,185
Total Revenues	$ 659,548	$ 552,756

(a) Amounts included affiliate and nonaffiliated revenues.
(b) Amounts included affiliate and nonaffiliated revenues. The affiliated revenues were $9 million and $10.6 million for years ended December 31, 2021 and 2020, respectively.

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 Reliability Pricing Model (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 encompass a time frame greater than a year, where the performance obligation within 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, 2021. Fixed performance obligations primarily include wholesale transmission services, electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. The amounts shown in the table below include affiliated and nonaffiliated revenues.

2022	2023-2024	2025-2026	After 2026	Total
		(in thousands)		
$ 36,211	$ 2,870	$ 2,870	$ 1,435	$ 43,386

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, 2021 and 2020, 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, 2021 and 2020, respectively.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on KPCo's balance sheets in Customer Accounts Receivable. 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, 2021 and 2020, respectively. See "Securitized Accounts Receivable - AEP Credit" section of Note 12 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 $9.1 million and $8.3 million, respectively, as of December 31, 2021 and December 31, 2020.

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, 2021 and 2020, respectively.

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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 Comprehensiv Income (j)
1	Balance of Account 219 at Beginning of Preceding Year				789,723			789,723		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				88,672			88,672		
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)				88,672			88,672	41,016,505	41,105,17
5	Balance of Account 219 at End of Preceding Quarter/Year				878,395			878,395		
6	Balance of Account 219 at Beginning of Current Year				878,395			878,395		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				871,447			871,447		
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)				871,447			871,447	50,149,812	51,021,25
10	Balance of Account 219 at End of Current Quarter/Year				1,749,842			1,749,842		

FERC FORM No. 1 (NEW 06-02)

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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)	2,915,567,696	2,915,567,696					
4	Property Under Capital Leases	13,610,347	13,610,347					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	217,614,784.10	217,614,784.10					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	3,146,792,827	3,146,792,827					
9	Leased to Others							
10	Held for Future Use	556,145	556,145					
11	Construction Work in Progress	95,340,895	95,340,895					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	3,242,689,868	3,242,689,868					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,159,640,985	1,159,640,985					
15	Net Utility Plant (13 less 14)	2,083,048,883	2,083,048,883					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	1,134,142,286	1,134,142,286					
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	25,498,698	25,498,698						
22	Total in Service (18 thru 21)	1,159,640,985	1,159,640,985						
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)	1,159,640,985	1,159,640,985						

FERC FORM No. 1 (ED. 12-89)

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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)					

FERC FORM No. 1 (ED. 12-89)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	51,793,805	11,006,157	3,723,377			59,076,584
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	51,846,724	11,006,157	3,723,377			59,129,504
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	4,833,438					4,833,438
9	(311) Structures and Improvements	80,553,804	532,832	92,908			80,993,728
10	(312) Boiler Plant Equipment	967,925,345	3,558,695	1,917,658			969,566,381
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	118,695,477	(19,422)	1,324			118,674,732
13	(315) Accessory Electric Equipment	31,647,075	192,540	151,775			31,687,839
14	(316) Misc. Power Plant Equipment	13,488,150	244,992	34,252			13,698,891
15		12,837,949	(1,528,856)	376,379			10,932,714

	(317) Asset Retirement Costs for Steam Production						
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,229,981,239	2,980,781	2,574,296			1,230,387,724
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						

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)	1,229,981,239	2,980,781	2,574,296			1,230,387,724
47	3. Transmission Plant						
48	(350) Land and Land Rights	38,465,240	53,556				38,518,796
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	10,995,610	2,779,563	296,790			13,478,383
50	(353) Station Equipment	231,654,013	24,599,289	1,998,629			254,254,673
51	(354) Towers and Fixtures	100,023,305	928,394	261,892			100,689,807
52	(355) Poles and Fixtures	165,152,534	24,587,439	2,145,188			187,594,785
53	(356) Overhead Conductors and Devices	156,112,174	9,558,558	755,522			164,915,210
54	(357) Underground Conduit	523,299	1,549				524,848
55	(358) Underground Conductors and Devices	382,321	18				382,339
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)	703,308,496	62,508,367	5,458,022			760,358,840
59	4. Distribution Plant						
60	(360) Land and Land Rights	8,104,249	1,027,711	1,278			9,130,682
61	(361) Structures and Improvements	7,093,227	2,267,796	56,695			9,304,328
62	(362) Station Equipment	130,494,438	11,724,808	1,121,300			141,097,946
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	247,409,284	18,946,057	1,911,401			264,443,940
65		279,052,328	23,986,890	2,175,702			300,863,515

	(365) Overhead Conductors and Devices						
66	(366) Underground Conduit	7,922,238	259,574	8,590			8,173,222
67	(367) Underground Conductors and Devices	12,123,528	306,855	49,660			12,380,723
68	(368) Line Transformers	146,407,709	7,281,183	2,295,747			151,393,145
69	(369) Services	68,118,429	2,951,588	398,124			70,671,893
70	(370) Meters	25,155,119	512,681	313,063			25,354,737
71	(371) Installations on Customer Premises	18,547,926	2,897,320	2,082,603			19,362,643
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	4,516,813	272,644	115,908			4,673,548
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	954,945,288	72,435,107	10,530,072			1,016,850,323
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	1,729,399					1,729,399
87	(390) Structures and Improvements	27,038,439	755,243	34,536			27,759,147
88	(391) Office Furniture and Equipment	2,639,386					2,639,386
89	(392) Transportation Equipment	14,768					14,768
90	(393) Stores Equipment	298,292	2,898				301,190

91	(394) Tools, Shop and Garage Equipment	6,390,251	159,899	65,186			6,484,964
92	(395) Laboratory Equipment	237,153	22,283	31,455			227,981
93	(396) Power Operated Equipment	5,931					5,931
94	(397) Communication Equipment	16,467,235	8,565,985	26,942			25,006,278
95	(398) Miscellaneous Equipment	1,858,268	285,083	15,126			2,128,225
96	SUBTOTAL (Enter Total of lines 86 thru 95)	56,679,122	9,791,391	173,244			66,297,269
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)	56,837,942	9,791,391	173,244			66,456,088
100	TOTAL (Accounts 101 and 106)	2,996,919,689	158,721,803	22,459,012			3,133,182,480
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)	2,996,919,689	158,721,803	22,459,012			3,133,182,480

FERC FORM No. 1 (REV. 12-05)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
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2						
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46						
47	TOTAL					

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Ramey Substation (4205)	10/01/2009	12/31/2023	556,145.38
21	Other Property:			
22				
23				
24				
25				
26				
27				
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47	TOTAL		556,145

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

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	AIR HEATER BASKET REPLACEMENT	1,111,731
2	Ed-Ci-Kepco-D Ast Imp	2,825,421
3	Hazard Station Rehab	3,213,771
4	KPCo - T BlnktProj Under $3M	1,383,041
5	KPCo D Work	1,020,310
6	KPCo T Work	1,280,901
7	KPCo T Work	5,318,317
8	KPCo T Work	1,862,409
9	KPCo T Work	2,460,182
10	KPCo-D Baseline Work	6,479,955
11	KPCO-D Telecom	1,489,480
12	KY Next Generation Radio Sys	9,715,779
13	KYPCo Distr Pre Eng Parent	4,173,910
14	KYPCo Trans Pre Eng Parent	1,592,733
15	Leslie Station Rehab	2,461,409
16	Millbrook P-SPoint - KPCo CI	1,494,534
17	Mitchell Catalyst Replacement	1,350,365
18	ML U0 ELG Compliance	5,466,871
19	Morehead Station Rehab	1,920,969
20	NGUCS Weddington & Leatherwood	1,047,840
21	ROW Capital Widening & Removal	6,726,648
22	T/KP/Capital Blanket - KYPCo	1,313,114
23	T/KP/Transmission Work	5,131,465
24	T/KY/KY Transmisison Work	2,500,783
25	WS-CI-KEPCo-G PPB	4,517,906
26	Other Minor Projects Which is under 5% or $1,000,000	17,481,050
43		95,340,895

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	1,069,757,123	1,069,757,123		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	93,483,264	93,483,264		
4	(403.1) Depreciation Expense for Asset Retirement Costs	155,861	155,861		
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):	72,194	[(a)] 72,194		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	93,711,319	93,711,319		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(18,533,119)	(18,533,119)		
13	Cost of Removal	(11,586,906)	[(b)] (11,586,906)		
14	Salvage (Credit)	1,219,423	[(c)] 1,219,423		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(28,900,602)	(28,900,602)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	(425,554)	[(d)] (425,554)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,134,142,286	1,134,142,286		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	558,989,898	558,989,898		

21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	248,881,002	248,881,002		
26	Distribution	304,769,753	304,769,753		
27	Regional Transmission and Market Operation				
28	General	21,501,633	21,501,633		
29	TOTAL (Enter Total of lines 20 thru 28)	1,134,142,286	1,134,142,286		

FOOTNOTE DATA

(a) Concept: OtherAccounts

Big Sandy Ash Pond deferred depreciation expense(ref: Case No. 2012-00578)	$ 284,643
Environmental costs recovered per KPSC Order Case No. 2014-00396	$ (226,465)
Asbestos ARO depreciation expense in account 1080013	$ 14,016
Total	$ 72,194

(b) Concept: CostOfRemovalOfPlant

Includes $5,822,882 of removal cost in retirement work in progress (RWIP).

(c) Concept: SalvageValueOfRetiredPlant

Includes ($722,459) of salvage in retirement work in progress (RWIP).

(d) Concept: OtherAdjustmentsToAccumulatedDepreciation

ARO Reserve in acct 1080013	$ (307,661)
Adjust gain/loss for Big Sandy U0 retirement	$ (117,893)
TOTAL	$ (425,554)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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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25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								
41								
42	Total Cost of Account 123.1 $		Total					

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	21,135,130	9,489,812	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	1,351,909	599,696	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	8,898,527	10,002,298	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	10,586,290	9,932,874	Electric
8	Transmission Plant (Estimated)	9,758	2,428	Electric
9	Distribution Plant (Estimated)	185,890	427,729	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[(a)]45,402	[(b)]55,324	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	19,725,867	20,420,653	
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	42,212,906	30,510,161	

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

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.

FERC FORM No. 1 (REV. 12-05)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year 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	249,749	8,620,509	63,995		63,996		65,460		1,389,055		1,832,255	8,620,509
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	1,392								54,271		55,663	
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	2,792	68,067									2,792	68,067
19	Other:												
20	Allowances Used												

20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Consent Decree Surrenders			14,084								14,084	
23													
24													
25													
26													
28	Total			14,084								14,084	
29	Balance-End of Year	248,349	8,552,442	49,911		63,996		65,460		1,443,326		1,871,042	8,552,442
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	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	
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												

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	43,801		8,352		8,352		8,815				69,320	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	(1,563)		(1,617)		(1,617)		(1,617)				(6,414)	
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	1,674										1,674	
19	Other:												
20	Allowances Used												
20.1	Allowances Used												

21	Cost of Sales/Transfers:												
22	Wolverine Power Supply Cooperative, Inc.	928										928	
23													
24													
25													
26													
28	Total	928										928	
29	Balance-End of Year	39,636		6,735		6,735		7,198				60,304	
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

FERC FORM No. 1 (ED. 12-95)

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

FERC FORM No. 1 (ED. 12-88)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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					

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	11,599	186	10,026	186
3	AF1-162	9,639	186	9,215	186
4	AG1-066	2,220	186	2,032	186
5	AG2-184	1,716	186	1,680	186
6	AG2-567	1,427	186	1,375	186
7	AG2-678	968	186	916	186
8	AG2-679	1,538	186	1,463	186
9	AG2-681	1,195	186	1,130	186
10	AG2-682	975	186	911	186
11	AG2-685	1,224	186	1,149	186
12	PJM - #AD2-105	(13)	186		
13	PJM - #AD2-106	(12)	186		
14	PJM - #AD2-107	(5)	186		
15	PJM - #AF1-130	(363)	186		
16	PJM - #AF1-162	(145)	186		
17	PJM - #AF1-162	(224)	186		
18	PJM - #AF2-018	8,663	186	8,255	186
19	PJM - #AF2-328	(243)	186		
20	PJM - #AF2-328	1,459	186	1,486	186
21	PJM - #AG1-066	2,222	186	2,902	186
22	PJM - AF1-233	(16)	186		
23	PJM - AF1-251	(7)	186		
24	PJM - AF1-256	(23)	186		
25	PJM - AF1-256	(8)	186		
26	PJM - AF2-017	(76)	186		

27	PJM AC1-101 & 102	5,849	186		
20	Total				
21	**Generation Studies**				
22	Spicewood Solar Feasability			55,000	183
39	Total				
40	Grand Total				

FERC FORM No. 1 (NEW. 03-07)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Storm Expenses - Kentucky PSC Case No. 2017-00179 - Amortz period: January 2018 - December 2023	4,233,112		593	2,066,559	2,166,553
2	KY Deferred Interest on 7.32% Note Case No. 2020-00174		650,110	427/431	162,527	487,582
3	SFAS 109 Deferred FIT	38,132,253	18,371,574	282/283	17,749,910	38,753,917
4	Unrecovered Fuel Cost		24,850,294	501/254	16,634,124	8,216,170
5	SFAS 109 Deferred SIT	117,320,924	9,518,545	282/283	36,809,732	90,029,737
6	KY Steam Maint O/U		696,194	512	223,955	472,239
7	Post In-Service AFUDC Hanging Rock/Jefferson 765 KV LineAmortz period: Dec 1984 - Nov 2032	398,376		406	33,408	364,968
8	PJM Greenhat Default Deferral		205,840			205,840
9	Depreciation Expense - Hanging Rock/Jefferson 765 KV LineAmortz period: Dec 1984 - Nov 2032	62,065		406	5,208	56,857
10	Unrecovered Plant - Big Sandy Kentucky PSC Case No. 2014-00396	256,509,062				256,509,062
11	IGCC Pre-Construction Costs Kentucky PSC Case No. 2014-00396	1,038,378		506	53,250	985,128
12	CCS FEED Study Costs Kentucky PSC Case No. 2014-00396	680,830		506	34,914	645,916
13	SFAS 112 Post Employment Benefit	3,437,459	390,243	926	418,148	3,409,554
14	Spent AROs - Big Sandy Coal Kentucky PSC Case No. 2014-00396	107,135,686	4,483,513	411	2,042,441	109,576,758
15	SFAS 158 Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans	29,049,719	39,278,378	129/190/219	56,091,699	12,236,398
16	Big Sandy Recovery Over/Under Kentucky PSC Case No. 2014-00396	(26,031,907)	116,516	407	12,462,415	(38,377,806)

17	Big Sandy Retirement Rider Unit 2 O&M Kentucky PSC Case No. 2014-00396	925,723	2,502			928,225
18	Unrealized Loss on Forward Commitments	202,015	3,889,623	175/182/244/456	4,019,413	72,224
19	Deferred Depreciation - Environmental Kentucky PSC Case No. 2014-00396	6,146,236	6,464,638	403	6,691,103	5,919,771
20	Netting of Trading Activities related toUnrealized Gains/Losses on Forward Commitmentsbetween Regulated Assets/Liabilities	(202,015)	1,821,658	254	1,691,867	(72,224)
21	BS1OR Under Recovery Kentucky PSC Case No. 2014-00396	1,083,437	702,349	407/928	1,063,495	722,291
22	NERC Compliance and Cybersecurity Costs Kentucky PSC Case No. 2014-00396	638,387	775,327	431/404	189,624	1,224,091
23	Capacity Charge Tariff Kentucky PSC Case No. 2014-00396, TFS 2016-00430	562,897	386,125	440/442/444	542,596	406,426
24	SFAS 106 Medicare SubsidyAmortz period: Jan 2013 - Dec 2024	866,480		926	216,620	649,860
25	Rate Cases Expenses	391,585	71,357	928	234,511	228,431
26	OSS Margin Sharing Kentucky PSC Case No. 2017-00179	1,554,871	2,178,888	561/440	3,361,744	372,015
27	Under-Recovery of PJM True-UpAmortz period: Jan 2021-Dec 2021	94,748		456	94,748	
28	Rockport Capacity Deferral Kentucky PSC Case No. 2017-00179	41,267,042	7,576,789	431	1,315,987	47,527,845
29	PJM RTEP Costs Deferral	99,980		242/565	99,980	
30	Cost of Removal-Big Sandy CoalKentucky PSC Case No. 2014-00396	(26,510,255)	1,639,854	108	31,550	(24,901,951)
31	KY Under-recovered PPA Rider	22,469,853	12,754,531	566	6,497,289	28,727,095
32	2020 KY Storm Deferral	10,707,896	51,793,111	593/571	5,995,160	56,505,847
33	NBV - AROs Retired PlantsKentucky PSC Case No. 2014-00396	9,916,947	2,368,066	411	7,564,222	4,720,791
34	Under-Recovery of PJM True-UpAmortz period: Jan 2022-Dec 2022		330,235			330,235
35	PJM 2020 Transmission DeferralAmortization period: Jan 2022-Dec 2022		973,425			973,425
36	M&S - Retiring PlantsKentucky PSC Case No. 2014-00396	3,015,785				3,015,785
44	TOTAL	605,197,569	192,289,685		184,398,199	613,089,054

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

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Deferred Property Tax	20,542,625	23,203,316	408	22,967,953	20,777,988
2	Agency Fees - Factored A/R	1,095,198	12,476,705	142/184	12,529,124	1,042,779
3	Unamortized Credit Line Fees	116,117	381,404	431	144,312	353,209
4	Amortized thru June 2021					
5	Deferred Lease Assets	48,571	233,552	143/184	195,348	86,775
6	Estimated Barging Bills					
7	Miscellaneous Items	5,925	5,826	565/588	18,729	(6,978)
8	Allowance		18,546	232	11,400	7,146
9	Trnsrce OU Acctg for Def Asset		446,610	565	392,752	53,858
47	Miscellaneous Work in Progress	724,522				478,103
48	Deferred Regulatroy Comm. Expenses (See pages 350 - 351)					
49	TOTAL	22,532,958				22,792,880

FERC FORM No. 1 (ED. 12-94)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Provision Revenue Refunds	66,418	(28,026)
3	Accrued BK ARO Cost	5,170,552	3,716,369
4	Int Exp Capd for Tax	5,545,632	5,756,007
5	Accrued Book Pension	(8,965,093)	(8,489,702)
6	NOL State Deferred Tax Asset	9,489,056	13,098,501
7	Other	3,356,058	9,189,875
8	TOTAL Electric (Enter Total of lines 2 thru 7)	14,662,623	23,243,024
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.0	Other (Specify)	[(a)]87,330,547	70,819,425
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	101,993,170	94,062,449

Notes

FERC FORM NO. 1 (ED. 12-88)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	404,518	628,222
SFAS 109-Regulatory Assets - 190.3, 190.4 & 190.6	87,159,526	70,656,351
SFAS 133	-	-
Accu Def Income Taxes Pension-OCI	(233,497)	(465,148)
Total	$ 87,330,547	$ 70,819,425

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

Balance at Beginning of Year	$ 101,993,170
(Less) Amounts Debited to:	
(a) Account 410.1	(11,504,139)
(b) Account 410.2	(638,797)
(c) 1823/254/219/129/427	(19,457,573)
(Plus) Amounts Credited to:	
(a) Account 411.1	19,825,990
(b) Account 411.2	1,121,051
(c) 1823/254/219/129/427	2,722,747
Balance at End of Year	$ 94,062,449

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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					0				
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

FERC FORM NO. 1 (ED. 12-91)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2022-04-06	Year/Period of Report End of: 2021/ 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.

Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
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.
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.
Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	523,324,094
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	523,324,094
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	2,811,185
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
16	Ending Balance Amount	2,811,185
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	526,135,279

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	0

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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 fr 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 (
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such 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
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, 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
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securitie
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 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)
1	Bonds (Account 221)									
2										
3										
4										
5	Subtotal									
6	Reacquired Bonds (Account 222)									
7										
8										
9										
10	Subtotal									
11	Advances from Associated Companies (Account 223)									
12										
13										
14										
15	Subtotal									
16	Other Long Term Debt (Account 224)									
17			75,000,000					06/13/2003	12/01/2032	06/13/2003

	[(a)] Senior Unsecured Notes - 5.625%, Series D									
18	Senior Unsecured Notes - 7.250%, State Commission Authority Case # 2008-00442		40,000,000					06/18/2009	06/18/2021	06/18/2009
19	Senior Unsecured Notes - 8.030%, State Commission Authority Case # 2008-00442		30,000,000					06/18/2009	06/18/2029	06/18/2009
20	Senior Unsecured Notes - 8.130%, State Commission Authority Case # 2008-00442		60,000,000					06/18/2009	06/18/2039	06/18/2009
21	Senior Unsecured Notes - 4.180%, Series A State Commission Authority Case# 2014-00210		120,000,000					09/30/2014	09/30/2026	09/30/2014
22	Senior Unsecured Notes - 4.33%, Series B State Commission Authority Case# 2014-00210		80,000,000					12/30/2014	12/30/2026	12/30/2014
23	[(b)] West Virginia Economic Development Authority Mitchell Project Series 2014A State Commission Authority Case# 2013-00410		65,000,000					06/26/2014	04/01/2036	06/26/2014
24	Local Bank Term Loan, State Commission Authority Case# 2014-00210		75,000,000					11/05/2014	10/26/2022	11/05/2014
25	Senior Unsecured Notes - 3.13%, Series F		65,000,000					09/12/2017	09/12/2024	09/12/2017

26	Senior Unsecured Notes - 3.35%, Series G		40,000,000					09/12/2017	09/12/2027	09/12/2017
27	Senior Unsecured Notes - 3.45%, Series H		165,000,000					09/12/2017	09/12/2029	09/12/2017
28	Senior Unsecured Notes - 4.12%, Series I		55,000,000					09/12/2017	09/12/2047	09/12/2017
29	(c) Local Bank Term Loan, State Commission Authority Case# 2019-00072		125,000,000					03/06/2020	03/06/2022	03/06/2020
30	(d) Term Loan - KY State Commission Authority: Case No. 2021-00131		150,000,000					06/17/2021	06/17/2023	06/17/2021
31	Subtotal		1,145,000,000							
33	TOTAL		1,145,000,000							

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription

The $75 million multiple draw term loan was issued on November 5, 2014. The interest rate is variable and the maturity date is November 5, 2018. Note was reissued October 26, 2018 with a new maturity date of 10/26/2022.

(b) Concept: ClassAndSeriesOfObligationCouponRateDescription

Issuance: West Virginia Economic Development Authority, Mitchell Project Series 2014A
Principal Amount: $65,000,000
Date of Issuance: 06/26/2014
Date of Maturity: 04/01/2036
Puttable Date: Bonds were subject to mandatory tender for purchase on 06/26/2017. Issuance expense of 675,501 was fully amortized as of 06/19/2017.

These bonds were re-marketed 06/19/2017:
Issuance: West Virginia Economic Development Authority, Mitchell Project Series 2014A
Principal Amount: $65,000,000
Date of Issuance: 06/19/2017
Date of Maturity: 04/01/2036
Puttable Date: Bonds are subject to mandatory tender for purchase on 6/19/2020. Issuance expense of 146,250 to be amortized through 06/19/2020.

Issuance: West Virginia Economic Development Authority, Mitchell Project Series 2014A
Principal Amount: $65,000,000
Date of Issuance: 06/19/2020
Date of Maturity: 04/01/2036
Puttable Date: Bonds are subject to mandatory tender for purchase on 6/19/2023. Issuance expense of 330,220 to be amortized through 06/19/2023.

(c) Concept: ClassAndSeriesOfObligationCouponRateDescription

The $125 million multiple draw term loan was issued on March 6, 2020. The interest rate is variable and the maturity date is March 6, 2022.

(d) Concept: ClassAndSeriesOfObligationCouponRateDescription

The $150 million multiple draw term loan was issued on June 17, 2021. The interest rate is variable and the maturity date is June 17, 2023.

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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)	50,149,812
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](56,981,905)

28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

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	50,150
Federal Income Taxes	(23,113)
State Income Taxes	(4,366)
	—
Pre-Tax Book Income`	22,671
Excess Tax vs Book Depreciation	22,886
AFUDC and Other Capitalization Differences	(198)
Book Unit of Property Adjustment	(42,563)
Removal Cost	(11,866)
Pollution Control Equipment	7,610
Property Tax	—
Provision for Revenue Refunds	-185
Deferred Fuel	(8,216)
Self Insurance / Worker's Comp	-30
Accrued Book Pension Expense	2,336
Deferred Storm Damage	2,067
Misc Book Accruals, Reserves & Deferrals	(56,118)
Non Deduct expenses	1,564
Total Tax Accruals	1,009
Capitalized Software	2,120
Reg-Asset unrecovered plant	—
Mark-to-Market	—
Emission Allowances	(68)
Others	—

FOOTNOTE DATA

Taxable Income before State Taxes	(56,982)
State & Local Current Tax	—
Federal Taxable Income	(56,982)
FIT on Current Year Taxable Income (21%)	(11,966)
Adjustment due to System Consolidation (a)	(11,966)
NOL Reclass	(6,589)
Tax Credit CFWD	
ALT Min Tax	
ETR Adjustment	
R&D Credit - Current	31
Estimated Tax Currently Payable (b)	(6,558)
Current Tax (a) - (b)	(5,408)
Adjustments of Prior Year's Accruals	2,438
Tax Expense for R/C of Net Operating Loss (Prior Yr)	
Estimated Current Federal Income Taxes	(2,970)

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 2021 System. Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by October 2022. 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

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

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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 durin 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, sho 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 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, 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, identifyin
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
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmit
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 pertair 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 colum 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)
40	TOTAL				36,555,700.00	879,231.00	29,098,711.00	21,324,179.00	1.00	44,350,258	899,25

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	26		(26)		
8	TOTAL Electric (Enter Total of lines 2 thru 7)					26		(26)		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL							0		

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	TV Pole Attachments	143,406	186,454,184	862,948	867,058	147,516
2	Customer Advance Receipts	2,838,303	142,232	2,838,303	1,833,564	1,833,564
3	Deferred Gain: Fiber Optic Agrmts-In Kind SvcAmortize through June 2026	88,249	124	15,870		72,379
4	ABD - Deferred Revenues				104,509	104,509
5	Deferred Revenue Fiber Optic Lines-Sold-Defd Rev Amortize through January 2025	8,283	451	5,544		2,739
6	IPP - System Upgrade Credits	354,678	234	358,486	3,808	
7	Miscellaneous	132,695	232,561,566	138,042	6,141	794
8	Contribution Aid of Construction	60,514	107,108	60,514	185,561	185,561
9	Deferred Revenue	97,173	143,186	97,173	66,207	66,207
10	Deferred Rev-Bonus Lease	73,994	421	22,767		51,227
11	NERC Penalties	264,458	242,426	169,148		95,310
47	TOTAL	4,061,753		4,568,795	3,066,849	2,559,807

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities	47,839,411	406	2,226,155							45,613,662
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	47,839,411	406	2,226,155							45,613,662
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	(17,694,477)					254	406	254	628,008	(17,066,875)

17	TOTAL (Acct 281) (Total of 8, 15 and 16)	30,144,934	406	2,226,155				406		628,008	28,546,787
18	Classification of TOTAL										
19	Federal Income Tax	30,144,934	406	2,226,155				406		628,008	28,546,787
20	State Income Tax										
21	Local Income Tax										

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Page 272-273

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	(17,694,477)	(406)	628,008	(17,066,875)
Total Line 16	(17,694,477)	(406)	628,008	(17,066,875)

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

Page 272-273

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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 accelerate amortization.
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)	Bal End
1	Account 282										
2	Electric	372,208,787	18,117,510	30,552,433					190		359,
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	372,208,787	18,117,510	30,552,433							359,
6	Others	[(a)](101,139,437)					1823/254	4,391,542	1823/254	25,701,949	(79,8
9	TOTAL Account 282 (Total of Lines 5 thru 8)	271,069,350	18,117,510	30,552,433				4,391,542		25,701,949	279,
10	Classification of TOTAL										
11	Federal Income Tax	271,069,350	18,117,510	30,552,433				4,391,542		25,701,949	279,
12	State Income Tax										
13	Local Income Tax										

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

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Line 6 Footnote

	Beg Bal	Debits	Credits	End Bal
Non-Utility	0	0	0	0
SFAS 109	(101,139,437)	4,391,542	25,701,949	(79,829,030)
Total Other - Line 6	(101,139,437)	4,391,542	25,701,949	(79,829,030)

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Page 274-275

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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 28
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Bala End
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Deferred Fuel Costs		4,393,897	2,668,502							1,7
4	Mark-to-Market	68,241,818	1,396,679	4,567,886							65,
5	Capitalized Software - Book	5,973,933	911,003	23,545							6,8
6	Emission Allowances	1,824,799	223,933	224,128							1,8
7	Reg Asset - SFAS 112	721,868	77,456	83,317							7
8	Other	52,569,347	23,349,598	23,733,205							52,
9	TOTAL Electric (Total of lines 3 thru 8)	129,331,765	30,352,566	31,300,583							128,3
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	[(a)]117,501,573				95,720	1823/254	48,712,292	1823/254	25,645,234	94,3
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	246,833,338	30,352,566	31,300,583		95,720		48,712,292		25,645,234	222,7

20	Classification of TOTAL										
21	Federal Income Tax	126,472,356	30,352,566	30,847,871		95,720		11,902,560		16,126,690	130,
22	State Income Tax	120,360,981		452,712				36,809,732		9,518,545	92,
23	Local Income Tax										

NOTES

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

Page 276-277

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Line 18 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Non-Utility	95,720	—
SFAS 109	117,405,853	94,338,796
SFAS 133	0	0
Total	$ 117,501,573	$ 94,338,796

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	Home Energy Assistance Program	474,332	[(a)] 142/235/237/450/451/460	2,313,227	2,975,335	1,136,440
2	SFAS 109 Deferred FIT	244,040,761	[(b)] 190/282/283	43,310,995	1,267,345	201,997,111
3	Kentucky Reliability	117,554	593	1,938,502	2,204,294	383,347
4	Over Recovered Fuel Cost	313,289	182	313,289		
5	PJM Trans Enhancement Reg Liability	2,636,457	565	619,368	626,601	2,643,690
6	KY- DSM Over Recovery	9,479	182	82,518	112,355	39,316
7	Netting of Trading Activities related toUnrealized Gains/Losses on Forward Commitmentsbetween Regulated Assets/Liabilities	(2,294,442)	182	1,691,867	1,821,658	(2,164,651)
8	Unrealized Gain on Forward Commitments	2,650,299	175, 244	2,134,115	4,847,410	5,363,594
9	Steam Maintenance Levelized Reg LiabilityKY Case No. 2017-00179	1,332,349			765,411	2,097,760
41	TOTAL	249,280,078		52,403,881	14,620,409	211,496,606

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment
142,235,237,450,451,456
(b) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment
190/282/283 Line No.

FERC FORM NO. 1 (REV 02-04)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	281,787,992	236,963,474	1,979,060	1,990,291	133,805	134,284
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	159,833,921	139,363,548	1,144,445	1,152,737	30,222	30,041
5	Large (or Ind.) (See Instr. 4)	142,303,180	123,054,180	1,960,411	1,963,685	1,079	1,120
6	(444) Public Street and Highway Lighting	2,032,165	1,898,034	9,393	9,765	310	317
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)]585,957,257	[(d)]501,279,236	5,093,309	5,116,477	165,416	165,762
11	(447) Sales for Resale	43,087,990	18,775,107	887,455	469,830	12	23
12	TOTAL Sales of Electricity	629,045,247	520,054,343	5,980,764	5,586,308	165,428	165,785
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	629,045,247	520,054,343	5,980,764	5,586,308	165,428	165,785
15	Other Operating Revenues						
16		1,311,974	1,249,627				

	(450) Forfeited Discounts						
17	(451) Miscellaneous Service Revenues	[(b)]256,524	171,555				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	5,841,043	9,050,959				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[(c)]838,181	810,654				
22	(456.1) Revenues from Transmission of Electricity of Others	22,254,859	21,418,819				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	30,502,581	32,701,614				
27	TOTAL Electric Operating Revenues	659,547,828	552,755,957				

Line12, column (b) includes $ (2,618,416) of unbilled revenues.
Line12, column (d) includes (86,434) MWH relating to unbilled revenues

FERC FORM NO. 1 (REV. 12-05)

Page 300-301

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: SalesToUltimateConsumers

Detail of Unmetered Sales - 2020

	Revenue	MWH	Average No. of Customers
Residential	6,448,479.25	25,476.31	38,699.67
Commercial	3,154,652.51	14,776.12	6,835.08
Industrial	150,722.90	760.05	208.50
Public Street Lighting	36,519.95	108.19	35.00
Total	9,790,374.61	41,120.67	45,778.25

(b) Concept: MiscellaneousServiceRevenues

Customer Service Revenue including connects, reconnects, disconnects, temporary services and other charges billed to customers.

(c) Concept: OtherElectricRevenue

Description	**2021 YTD**	**20202 YTD**
Oth Elect Rev - Demand Side Management Program	284,168.00	539,898.00
All Other (Under $250,000)	554,013.00	270,756.00
	838,181.00	**810,654.00**

(d) Concept: SalesToUltimateConsumers

Detail of Unmetered Sales - 2019

	Revenue	MWH	Average No. of Customers
Residential	5,895,371.00	25,744.00	38,078.00
Commercial	2,748,207.00	14,798.00	6,791.00
Industrial	131,546.00	770.00	207.00
Public Street Lighting	31,490.00	108.00	35.00
Total	8,806,614.00	41,420.00	45,111.00

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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)
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41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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)
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41	TOTAL Billed Residential Sales	2,025,039	283,526,017	133,805	15,134	0.1400
42	TOTAL Unbilled Rev. (See Instr. 6)	(45,979)	(1,738,025)			0.0378
43	TOTAL	1,979,060	281,787,992	133,805	14,791	0.1424

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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)
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41	TOTAL Billed Small or Commercial	1,167,644	160,520,710	30,222	38,636	0.1375
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(23,199)	(686,789)			0.0296
43	TOTAL Small or Commercial	1,144,445	159,833,921	30,222	37,868	0.1397

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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)
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41	TOTAL Billed Large (or Ind.) Sales	1,977,636	142,493,063	1,079	1,832,842	0.0721
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(17,225)	(189,883)			0.0110
43	TOTAL Large (or Ind.)	1,960,411	142,303,180	1,079	1,816,878	0.0726

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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)
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41	TOTAL Billed Commercial and Industrial Sales					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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)
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41	TOTAL Billed Public Street and Highway Lighting	9,425	2,035,884	310	30,403	0.2160
42	TOTAL Unbilled Rev. (See Instr. 6)	(32)	(3,719)			0.1162
43	TOTAL	9,393	2,032,165	310	30,300	0.2163

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	5,179,744	588,575,674	165,416	1,917,015	
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(86,435)	(2,618,416)			
43	TOTAL - All Accounts	5,093,309	585,957,258	165,416	1,917,015	

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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 dur Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for 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 intere 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 pro 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 supplie 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 i remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF 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 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 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 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 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 ar 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 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 sche 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 i 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 bi in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in colu 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 Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand 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, 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 purchase
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 The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amou (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW) Average Monthly NCP Demand (e)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)
1	ALLEGHENY ELECTRIC COOPERATIVE	OS	(b) NOTE 1				2,495		102,950	
2	AMEREX POWER, LTD	OS	NOTE 1				0		(267)	
3	B.P. ENERGY COMPANY	OS	NOTE 1				(6,540)		(151,556)	

4	[a] CITIGROUP ENERGY INC.	OS	[c] NOTE 1				0		(46,567)	
5	CITY OF OLIVE HILL	RQ	KPCO 52				21,742	818,845	1,207,512	
6	CITY OF VANCEBURG	RQ	KPCO 51				56,826	2,019,243	2,816,141	
7	DUQUESNE LIGHT COMPANY	OS	NOTE 1				2,530		102,260	
8	EVOLUTION MARKETS FUTURES, LLC	OS	NOTE 1				0		(1,266)	
9	FIRSTENERGY TRADING SERVICES	OS	NOTE 1				14,162		571,390	
10	ICAP ENERGY LLC	OS	NOTE 1				0		(500)	
11	IVG ENERGY, LTD	OS	NOTE 1				0		(977)	
12	OHIO POWER COMPANY (AUCTION)	OS	NOTE 1				7		204	
13	PJM INTERCONNECTION	OS	NOTE 1				776,484	4,176,440	33,312,108	
14	PJM INTERCONNECTION	RQ	VARIOUS				0			[d](1,698,223)
15	PPL ELECTRIC UTILITIES CORP	OS	NOTE 1				19,749		859,288	
16	RBC CAPITAL MARKET, LLC	OS	NOTE 1				0		(209)	
17	TRIDENT BROKERAGE SERVICES, LLC	OS	NOTE 1				0		(33)	
18	TULLETT PREBON AMERICAS CORP.	OS	NOTE 1				0		(40)	
19	WELLS FARGO SECURITIES, LLC	OS	NOTE 1				0		(998,752)	
15	Subtotal - RQ						78,568	2,838,088	4,023,653	(1,698,223)
16	Subtotal-Non-RQ						808,887	4,176,440	33,748,033	
17	Total						887,455	7,014,528	37,771,686	(1,698,223)

FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
An affiliated company
(b) Concept: RateScheduleTariffNumber
FERC Electric Tariff, First Revised Volume No. 5.
(c) Concept: RateScheduleTariffNumber
The PUCO (Public Utilities Commission Ohio) ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning June 2015. APCo, KPCo, I&M and WPCo participated in the auction process and were awarded tranches of OPCo's SSO load.
(d) Concept: OtherChargesRevenueSalesForResale
Amount represents transmission services and related charges
(e) Concept: RevenueFromSalesOfElectricityForResale
Margins for Off System Sales (OSS) reported in KPCO's generation formula rates are included in the total revenue amount. The margins are specifically identified in the ledger as a subset of the accounts that make up these OSS revenues.

FERC FORM NO. 1 (ED. 12-90)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	5,350,713	4,868,577
5	(501) Fuel	[(a)]80,123,189	72,861,049
6	(502) Steam Expenses	7,022,880	4,383,455
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	309,758	7,092
10	(506) Miscellaneous Steam Power Expenses	4,402,732	6,500,281
11	(507) Rents		
12	(509) Allowances	68,067	70,641
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	97,277,339	88,691,095
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,593,289	1,745,110
16	(511) Maintenance of Structures	1,693,654	2,374,875
17	(512) Maintenance of Boiler Plant	11,091,565	11,179,888
18	(513) Maintenance of Electric Plant	3,849,593	3,300,396
19	(514) Maintenance of Miscellaneous Steam Plant	1,431,603	1,548,477
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	19,659,705	20,148,746
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	116,937,044	108,839,841
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		
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	7	
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	7	
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)	7	
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	188,731,639	115,327,338
76.1	(555.1) Power Purchased for Storage Operations	0	
77	(556) System Control and Load Dispatching	345,020	393,703
78	(557) Other Expenses	554,118	520,289
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	189,630,777	116,241,330
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	306,567,827	225,081,171
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,675,797	2,438,642
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	309,116	334,283
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	886,000	1,042,127
89	(561.5) Reliability, Planning and Standards Development	126,575	91,614
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	329,196	312,761
93	(562) Station Expenses	[(b)]191,474	192,674
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	18,881	40,035
95	(564) Underground Lines Expenses	(1)	1
96	(565) Transmission of Electricity by Others	60,477,934	50,414,808

97	(566) Miscellaneous Transmission Expenses	4,912,907	(17,316,318)
98	(567) Rents	350	26,654
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	69,928,229	37,577,281
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	2,784	3,918
102	(569) Maintenance of Structures	9,622	3,298
103	(569.1) Maintenance of Computer Hardware	5,801	4,586
104	(569.2) Maintenance of Computer Software	96,782	263,536
105	(569.3) Maintenance of Communication Equipment	1,712	832
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	503,786	467,561
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	6,524,013	4,986,971
109	(572) Maintenance of Underground Lines	439	405
110	(573) Maintenance of Miscellaneous Transmission Plant	18,380	37,990
111	TOTAL Maintenance (Total of Lines 101 thru 110)	7,163,319	5,769,097
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	77,091,548	43,346,378
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	1,119,915	963,763
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,119,915	963,763
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		1,119,915	963,763

	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	829,970	758,510
135	(581) Load Dispatching	3,410	312
136	(582) Station Expenses	259,294	222,575
137	(583) Overhead Line Expenses	397,079	692,064
138	(584) Underground Line Expenses	152,750	151,144
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	78,060	83,521
140	(586) Meter Expenses	1,151,401	1,379,775
141	(587) Customer Installations Expenses	193,715	201,141
142	(588) Miscellaneous Expenses	2,424,122	4,770,802
143	(589) Rents	242,074	1,386,488
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	5,731,876	9,646,332
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	26,434	3,036
147	(591) Maintenance of Structures	8,122	111,506
148	(592) Maintenance of Station Equipment	683,774	337,490
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	33,683,296	32,329,792
150	(594) Maintenance of Underground Lines	19,443	78,228
151	(595) Maintenance of Line Transformers	52,827	45,466
152	(596) Maintenance of Street Lighting and Signal Systems	(8,742)	57,121
153	(597) Maintenance of Meters	50,515	34,857
154	(598) Maintenance of Miscellaneous Distribution Plant	20,541	41,156
155	TOTAL Maintenance (Total of Lines 146 thru 154)	34,536,210	33,038,652
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	40,268,086	42,684,984
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	22,750	19,105
160	(902) Meter Reading Expenses	554,574	630,110
161	(903) Customer Records and Collection Expenses	5,557,980	4,964,422
162	(904) Uncollectible Accounts	(36,810)	(88,289)
163	(905) Miscellaneous Customer Accounts Expenses	26,769	25,348
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	6,125,263	5,550,696

165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	43,142	(99,023)
168	(908) Customer Assistance Expenses	1,351,901	1,260,559
169	(909) Informational and Instructional Expenses	94,779	162,565
170	(910) Miscellaneous Customer Service and Informational Expenses	36,307	41,622
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	1,526,129	1,365,723
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		143
175	(912) Demonstrating and Selling Expenses	40,621	92,500
176	(913) Advertising Expenses	10,703	7,555
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	51,323	100,198
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	10,584,485	10,872,764
182	(921) Office Supplies and Expenses	510,863	609,578
183	(Less) (922) Administrative Expenses Transferred-Credit	1,108,389	1,016,796
184	(923) Outside Services Employed	2,602,573	1,923,757
185	(924) Property Insurance	(c)879,125	913,035
186	(925) Injuries and Damages	2,117,373	1,464,253
187	(926) Employee Pensions and Benefits	1,132,660	1,212,658
188	(927) Franchise Requirements	139,814	127,744
189	(928) Regulatory Commission Expenses	1,919,336	2,589,800
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	226,697	65,774
192	(930.2) Miscellaneous General Expenses	966,171	556,376
193	(931) Rents	256,777	259,106
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	20,227,484	19,578,049
195	Maintenance		
196	(935) Maintenance of General Plant	2,993,639	2,938,693
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	23,221,122	22,516,742
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	455,971,214	341,609,655

FERC FORM NO. 1 (ED. 12-93)

Page 320-323

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: FuelSteamPowerGeneration
The portion of account 501 that is excluded from the fuel costs in KPCo's generation formula rate is identified by a query of the general ledger.
(b) Concept: StationExpensesTransmissionExpense
Generation Step-Up Units' (GSUs) O&M expenses included in KPCo's generation formula rate are the ratio of GSU balances to all investment for plant accounts 352 & 353 multiplied by the balance in O&M accounts 562,569 & 570.
(c) Concept: PropertyInsurance
The insurance expenses for generation included in KPCo's generation formula rate are identified by a query of the general ledger.

FERC FORM NO. 1 (ED. 12-93)

Page 320-323

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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 fo 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. Explai 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 pro 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 consume

   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 conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not 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 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 f 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

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

   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 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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the co 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 avera 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 demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60 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
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the t
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, amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, r receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other 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 Pur (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 4
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)
1	(a) AEP GENERATING COMPANY	RQ	AEG 2				720,400			
2	PJM INTERCONNECTION	OS					2,755,570			
3	(b) ROCKPORT PURCHASE POWER	OS								
15	TOTAL						3,475,970	0	0	0

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Affiliated Company
(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Per KPSC Order Case No. 2017-00179, KPCO defers a portion of the non-fuel, non-environmental lease expenses incurred for Rockport Unit 2.

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-tr 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 company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or trun 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 Netwo Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accour 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 whic
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the subs where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for w 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 colum 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 t column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all othe 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 b no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including th
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on l
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)	Megawatt Hours Delivered (j)
1	PJM Network Integ Trans Rev Whlsle	Various	Various	FNO	[(a)] PJM OATT	Various	Various			
2	PJM Network Integ Trans Serv	Various	Various	FNO	PJM OATT	Various	Various			
3	PJM Trans Enhancement Rev	Various	Various	FNO	PJM OATT	Various	Various			
4	PJM Trans Enhancement Rev Whlsle	Various	Various	FNO	PJM OATT	Various	Various			
5	PJM Trans Enhancement Rev - Affil	Various	Various	FNO	PJM OATT	Various	Various			
6	PJM Network Integ Rev - Affil	Various	Various	FNO	PJM OATT	Various	Various			
7	PJM Point to Point Trans Service	Various	Various	LFP	PJM OATT	Various	Various			
8	PJM Trans Owner Admin Revenue	Various	Various	OLF	PJM OATT	Various	Various			

9	PJM Trans Owner Serv Rev Whlsle	Various	Various	OLF	PJM OATT	Various	Various			
10	PJM Power Factor Credits Rev Whlsle	Various	Various	OS	PJM OATT	Various	Various			
11	PJM Trans Owner Serv - Affil	Various	Various	OLF	PJM OATT	Various	Various			
12	East Kentucky Power Cooperative	Various	Various	OLF	PJM OATT	Various	Various			
35	TOTAL									

FERC FORM NO. 1 (ED. 12-90)

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
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39					
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41					
42					
43					
44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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]131,876	131,876
2	East KY Power Coop							
3	PJM - Enhancements	OS					[b]8,119,760	8,119,760
4	PJM - NITS	OS					[c]51,924,281	51,924,281
5	PJM - Trans Owner	OS					[d]302,017	302,017
	TOTAL							

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

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
Network Integration Transmission Service Charges - NITS (PJM OATT Schedule H)
(d) Concept: OtherChargesTransmissionOfElectricityByOthers
Transmission Owner Service (PJM OATT Tariff Sixth Revised Volume No. 1)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	144,911
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	388
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	611,087
7	AEP Service Corporation Billings	132,537
8	Intercompany Allocations	(55,593)
9	Corporate Money Pool Allocations	31,126
10	Corporate and Fiscal	68,622
11	Miscellaneous	33,093
46	TOTAL	966,171

FERC FORM NO. 1 (ED. 12-94)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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			8,819,731		8,819,731
2	Steam Production Plant	36,029,188	155,861			36,185,049
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	19,895,491				19,895,491
8	Distribution Plant	34,631,574				34,631,574
9	Regional Transmission and Market Operation					
10	General Plant	2,927,011				2,927,011
11	Common Plant-Electric					
12	TOTAL	93,483,264	155,861	8,819,731		102,458,856

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.

C. Factors Used in Estimating Depreciation Charges

Line No.	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	366	8.086	37 years		3.52	R2	
13	STEAM -- COAL/LIGNITE						
14	311 - Big Sandy	23.733		2	3.06		
15	367	12.354	44 years		3.52	R1	
16	311 - Mitchell	57.252		3	2.58		
17	368	150.826	25 years	(15)	3.52	R1.5	
18	312 - Big Sandy	77.507		2	4.45		
19	369	70.369	18 years		3.52	R2	
20	312 - Mitchell	883.72		3	2.96		
21	370	25.332	27 years		3.52	R0.5	
22	312 - Mitchell SCR	8.255		3	12.5		
23	371	19.245	11 years	(30)	3.52	L0	
24	314 - Big Sandy	63.108		2	2.78		
25	373	4.669	15 years	(15)	3.52	L0	
26	314 - Mitchell	55.567		3	1.67		
27	TOTAL DISTRIBUTION	1,009.161					
28	315 - Big Sandy	5.624		2	1.77		
29	315 - Mitchell	26.079		3	1.49		
30	GENERAL PLANT						
31	316 - Big Sandy	4.434		2	2.82		
32	389.1	0.036	75 years		1.59	R4	
33	316 - Mitchell	9.262		3	2.63		
34	390	27.746	35 years		3.97	L2	
35	391	2.639	35 years		3.2	SQ	
36	TOTAL COAL/LIGNITE	1,214.541					
37	392	0.015	30 years		3.52	SQ	
38	393	0.301	30 years		4.15	SQ	
39	TRANSMISSION						
40	350.1	33.943	75 years		1.44	R4	
41	394	6.36	30 years	9	4.2	SQ	
42	352	12.634	60 years	10	2.08	S3	
43	395	0.228	30 years		5.76	SQ	
44	352 - Big Sandy	0.01	60 years	10	2.08	S3	
45	396	0.006	25 years		5.43	SQ	
46	352 - Mitchell	0.072	60 years	10	2.08	S3	

47	397	22.587	22 years	(3)	5.66	SQ		
48	353	219.118	50 years	3	2.15	L0.5		
49	397.16	1.333	22 years	(3)	5.66	SQ		
50	353 - Big Sandy	0.603	50 years	3	2.15	L0.5		
51	398	2.087	20 years	3	6.73	SQ		
52	353 - Mitchell	11.523	50 years	3	2.15	L0.5		
53	TOTAL GENERAL	63.338						
54	353.16	2.054	50 years	3	2.15	L0.5		
55	354	100.574	51 years	10	2.61	S6		
56	[(a)] DEPRECIABLE SUM	3,018.501						
57	355	185.948	43 years	61	3.95	L3		
58	356	159.471	50 years	27	2.91	S6		
59	356.16	4.604	50 years	27	2.91	S6		
60	357	0.525	37 years		2.99	R2		
61	358	0.106	44 years		2.62	R1		
62	358.16	0.276	44 years		2.62	R1		
63	TOTAL TRANSMISSION	731.461						
64	DISTRIBUTION							
65	360.1	5.7	75 years		3.52	R4		
66	361	9.195	65 years		3.52	L0.5		
67	362	137.579	25 years	(25)	3.52	L0		
68	362.16	2.698	25 years	(25)	3.52	L0		
69	364	263.212	28 years		3.52	L0		
70	365	299.896	26 years	(25)	3.52	R1.5		

FERC FORM NO. 1 (REV. 12-03)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

The depreciable plant base is the November 30, 2021 total company depreciable plant.

FERC FORM NO. 1 (REV. 12-03)

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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) rela 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 previ
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 DU	
						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 (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)	Amou (k)
1	2016 - Kentucky Power Rate Case		126,180	126,180	22,177	Electric	928	104,003		928	22,1
2	KPSC - Case No. 2016-00180										
4	2019 Kentucky IRP Plan		2,077	2,077		Electric	928	2,077			
6	2019 Kentucky Environmental Compliance Plan		9,977	9,977		Electric	928	9,977			
8	Minor Items < $25,000		31,860	31,860		Electric	928	31,860			
10	2020 - Kentucky Power Base Case		315,740	315,740	369,408	Electric	928	103,407	71,357	928	212,3
11	KPSC - Case No. 2020-00174										
13	Kentucky PSC Investigation		202,094	202,094		Electric	928	202,094			
15	Kentucky AMI Program Filing		109,607	109,607		Electric	928	109,607			
17	Kentucky Solar Filing		19,354	19,354		Electric	928	19,354			
19	State Commission Fees		1,102,447	1,102,447		Electric	928	1,102,447			

46	TOTAL		1,919,336	1,919,336	391,585		1,684,826	71,357		234,5

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

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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:

Electric R, D and D Performed Internally:

Generation

hydroelectric

Recreation fish and wildlife
Other hydroelectric

Fossil-fuel steam
Internal combustion or gas turbine
Nuclear
Unconventional generation
Siting and heat rejection

Transmission

Overhead
Underground

Distribution
Regional Transmission and Market Operation
Environment (other than equipment)
Other (Classify and include items in excess of $50,000.)
Total Cost Incurred

Electric, R, D and D Performed Externally:

Research Support to the electrical Research Council or the Electric Power Research Institute
Research Support to Edison Electric Institute
Research Support to Nuclear Power Groups
Research Support to Others (Classify)
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	63,061		506	63,061	
2		2 items under $50,000	202		506	202	
3	A(1)e: Generation: Unconventional	1 item under $50,000			506		
4	A(2): Transmission	1 item under $50,000	3,278		566	3,278	
5	A(3): Distribution	1 items under $50,000	2,315		588	2,315	
6	A(5): Environment (other than equipment)	1 items under $50,000	10,021		506	10,021	
7	A(6): Other	2 items under $50,000	31,497		506,566,588	31,497	
8	A(6)a: Alternate Energy	1 item under $50,000	25		506	25	
9	A(6)f: Other (Metering)	1 item under $50,000	449		588	449	
10		1 item under $50,000	504		566,588	504	

	A(6)g: Other (program management)						
11	B: Electric R&D External	7 items under $50,000		22,036	506,566,588	22,036	
12	B(1): R&D support to the Research Council	EPRI Annual Portfolio		204,740	506	204,740	
13	or the Electric Power Research	Transmission EPRI Portfolio		75,652	566	75,652	
14	Institute	34 items under $50,000		362,894	506,566,588	362,894	
15	B(4): Research Support to Others	3 items under $50,000		7,961	506,566	7,961	

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	7,535,348		
4	Transmission	4,275		
5	Regional Market			
6	Distribution	2,212,943		
7	Customer Accounts	1,389,246		
8	Customer Service and Informational	198,050		
9	Sales			
10	Administrative and General	1,293,892		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	12,633,754		
12	Maintenance			
13	Production	4,484,080		
14	Transmission			
15	Regional Market			
16	Distribution	5,794,660		
17	Administrative and General	390,041		
18	TOTAL Maintenance (Total of lines 13 thru 17)	10,668,781		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	12,019,428		
21	Transmission (Enter Total of lines 4 and 14)	4,275		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	8,007,603		
24	Customer Accounts (Transcribe from line 7)	1,389,246		
25	Customer Service and Informational (Transcribe from line 8)	198,050		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	1,683,933		

28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	23,302,535	2,492,180	25,794,715
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			
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)	23,302,535	2,492,180	25,794,715
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	11,240,479	1,202,156	12,442,635
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	11,240,479	1,202,156	12,442,635
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,367,410	253,192	2,620,602
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,367,410	253,192	2,620,602
77	Other Accounts (Specify, provide details in footnote):			
78	188 - Research & Development	(498)		(498)
79	184 - Clearing Accounts	2,032,396	(2,032,396)	
80	163 - Stores Expense Undistributed	1,915,132	(1,915,132)	
81	185 - ODD Temporary Facilities	43,300		43,300
82	186 - Misc Deferred Debits	297,253		297,253
83	401 - Operation Expense - Nonassociated			
84	Other Accounts (Specify, provide details in footnote):			
85	426 - Political Activities	6,762		6,762
86	183 - Prelim Survey			
87	152 - Fuel Stock Undistributed	3,062,481		3,062,481
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	7,356,826	(3,947,528)	3,409,298
96	TOTAL SALARIES AND WAGES	44,267,250		44,267,250

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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: 04/06/2022	Year/Period of Report End of: 2021/ 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)				102,215,275
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)				(34,201,542)
4	Transmission Rights				(8,509,469)
5	Ancillary Services				1,099,763
6	Other Items (list separately)				
7	Congestion				8,721,984
8	Operating Reserves				733,472
9	Transmission Purchase Expense				1,662,311
10	Transmission Losses				7,134,723
11	Meter Corrections				(158,881)
12	Inadvertent				19,916
13	Capacity Credits				(4,176,440)
46	TOTAL				74,541,112

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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)						

FERC FORM NO. 1 (New 2-04)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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.

FERC FORM NO. 1 (New 2-04)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: 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

FERC FORM NO. 1 (NEW. 07-04)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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.

FERC FORM NO. 1 (NEW. 07-04)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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: 2022-04-06	Year/Period of Report End of: 2021/ 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)	5,093,309
3	Steam	3,103,344	23	Requirements Sales for Resale (See instruction 4, page 311.)	78,568
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	808,887
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	598,550
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	3,103,344	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	6,579,314
10	Purchases (other than for Energy Storage)	3,475,970			
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)	6,579,314			

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	600,741	18,844	1,021	29	9
30	February	768,658	106,154	1,067	8	8
31	March	513,537	21,580	982	8	8
32	April	430,063	24,145	848	2	9
33	May	443,004	35,335	839	25	17
34	June	608,815	164,444	924	29	17
35	July	654,349	168,502	918	28	17
36	August	634,489	138,322	958	24	17
37	September	505,143	83,080	862	14	17
38	October	415,722	31,610	697	11	17
39	November	471,586	12,548	948	23	8
40	December	533,207	38,220	972	23	9
41	Total	6,579,314	842,784			

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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 Mct.
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: [a] Mitchell-KEPCo Share
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		STEAM	STEAM	STEAM
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		CONVENTIONAL	OUTDOOR BOILER	OUTDOOR BOILER
3	Year Originally Constructed		1963	1971	1971
4	Year Last Unit was Installed		2016	1971	1971
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)		280.50	1,633.00	817.00
6	Net Peak Demand on Plant - MW (60 minutes)		296	1,572	786
7	Plant Hours Connected to Load		3,530	6,019	6,019
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	174	87
12	Net Generation, Exclusive of Plant Use - kWh		550,601,000	4,769,552,000	2,384,776,000
13	Cost of Plant: Land and Land Rights		1,734,844	6,197,188	3,098,594
14	Structures and Improvements		23,742,039	114,323,837	57,251,688
15	Equipment Costs		150,679,801	1,963,580,943	982,948,043
16	Asset Retirement Costs		6,618,088	10,450,133	4,314,626
17	Total cost (total 13 thru 20)		182,774,773	2,094,552,101.00	1,047,612,952
18			651.6035	1,282.6406	1,282.2680

	Cost per KW of Installed Capacity (line 17/5) Including				
19	Production Expenses: Oper, Supv, & Engr		2,454,899	4,880,365	2,895,815
20	Fuel		25,660,941	126,219,992	62,991,706
21	Coolants and Water (Nuclear Plants Only)		0		0
22	Steam Expenses		980	13,936,526	7,021,900
23	Steam From Other Sources		0		0
24	Steam Transferred (Cr)		0		0
25	Electric Expenses		1,011	617,495	308,747
26	Misc Steam (or Nuclear) Power Expenses		1,601,775	4,922,689	2,800,957
27	Rents		0		0
28	Allowances		4,563	63,878	63,504
29	Maintenance Supervision and Engineering		341,137	2,481,768	1,252,152
30	Maintenance of Structures		764,631	1,858,071	929,023
31	Maintenance of Boiler (or reactor) Plant		2,526,988	16,874,897	8,564,577
32	Maintenance of Electric Plant		1,215,477	5,266,469	2,634,116
33	Maintenance of Misc Steam (or Nuclear) Plant		616,314	1,630,538	815,290
34	Total Production Expenses	0	35,188,716	178,752,688	90,277,787
35	Expenses per Net kWh		0.0639	0.0375	0.0379

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	4,580,318	1,974,566	72,747	987,283	39,228
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,216,000	12,474	136,507	12,474	136,507
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5.502	53.762	96.727	53.762	96.727
41	Average Cost of Fuel per Unit Burned	5.516	55.750	89.463	55.750	82.952
42	Average Cost of Fuel Burned per Million BTU	4.536	2.235	15.604	2.235	14.469
43	Average Cost of Fuel Burned per kWh Net Gen	0.046	0.023	0.000	0.023	0.000
44	Average BTU per kWh Net Generation	10,337	10,410.000	0.000	10,410	0.000

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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.

FERC FORM NO. 1 (REV. 12-03)

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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: 04/06/2022	Year/Period of Report End of: 2021/ 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 pumpec 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, anc 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, Pa 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, i 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 on 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)	Gene Ty (r
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FERC FORM NO. 1 (REV. 12-03)

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

ENERGY STORAGE OPERATIONS (

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 locatio
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) :
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 inco
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 fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated powe
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 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 th

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)
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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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 kilov
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 s
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; c
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 con
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
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 ba
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 y
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 colum
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, g
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 operati
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 th
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 determ
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
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			La
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(
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	37.08	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			161.00	161.00	1	1.09	0	1		

	0135 WOOTEN	ARNOLD DELVINTA (LGE)							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	556.5 KCM ACSR	
21	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	3	14.77	0	1	795 KCM ACSR	
22	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	3	16.30	0	2	795 KCM ACSR	
23	0101 BIG SANDY, KY	W HUNTINGTON, WV	138.00	138.00	3	0.33	0	1	1033.5 KCM ACSR	
24	0102 BELLEFONTE, KY	N PROCTORVILLE, OH	138.00	138.00	3	1.10	1	1	397.5 MA	
25	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	3	5.91	0	1	397.5 MCMCU	
26	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	3	23.25	0	1		
27	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	3	2.30	0	1	636 MCMA	
28	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	1	16.09	17	1		
29	0107 LOGAN, WV	SPRIGG, KY	138.00	138.00	3	0.48	0	2	397 MCMA	
30	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	1.48	0	1	954KCM ACSR	
31	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	3.31	0	1	795KCM ACSR	
32	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	3	30.88	0	1	636KCM ACSR	
33	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	22.86	0	1	636KCM ACSR	
34	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	1	0.01	0	1	636KCM ACSR	
35	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	3	0.71	14	1	795 MCMA	
36	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	1	0.38	0	1		
37	0113 CHADWICK	KY ELECTRIC STEEL	138.00	138.00	1	8.09	0	1	795 MCMA	

38	0115 CHADWICK	COALTON	138.00	138.00	1	0.98	0	1	795 MCMA	
39	0133 CHADWICK EXTENSION		138.00	138.00		0.00	0	0		
40	0117 MILBROOK PARK, OH	FULLERTON	138.00	138.00	1	5.08	2	1	556.5 MCM	
41	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	1	25.83	0	1	795 MCMA	
42	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	3	0.63	0	0	1590 KCM	
43	0120 HATFIELD	SPRIGG	138.00	138.00	1	5.88	0	1	1033 MCM	
44	0121 HATFIELD	INEZ	138.00	138.00	1	14.67	0	1	1033.5 VAR	
45	0122 INEZ	LOVELY	138.00	138.00	1	6.86	0	1	1033.5 VAR	
46	0126 INEZ	MARTIKI	138.00	138.00	1	0.33	0	1	1033.5 VAR	
47	0127 BIG SANDY	INEZ	138.00	138.00	3	25.08	0	1	795 MCMA	
48	0106 DORTON	FLEMING	138.00	138.00	1	6.81	0	1	795 MCMA	
49	0106 DORTON	FLEMING	138.00	138.00	3	0.83	0	0	795 MCMA	
50	0108 BEAVER CREEK	SPRIGG #1	138.00	138.00	1	32.60	0	1	397 MCMA	
51	0124 BIG SANDY	SOUTH NEAL	138.00	138.00	1	0.01	0	1	1033.5 VAR	
52	0109 BEAVER CREEK	SPRIGG #3	138.00	138.00		0.00	0	0		
53	0125 BELLEFONTE	AK STEEL OXYGEN PLANT	138.00	138.00	3	0.22	0	2	795 ACSR	
54	0130 JOHNS CREEK	SPRIGG	138.00	138.00	3	13.00	0	0	1033 MCM	
55	0131 BAKER	BIG SANDY EXT.	138.00	138.00	3	1.00	0	1	1351 KCM	
56	0131 BAKER	BIG SANDY EXT.	138.00	138.00	1	0.05	0	2	2 - 1351KCM ACSR	
57	0128 INEZ	JOHNS CREEK	138.00	138.00	3	17.00	0	0	2-556.5 MCM	
58	0129 BEAVER CREEK	JOHNS CREEK	138.00	138.00	3	22.11	0	0	1033.5KCM ACSR	
59	0132 GRANGSTON LOOP		138.00	138.00	3	0.84	0	2	556.5 KCM ACSR	
60	0137 HAYS BRANCH	MORGAN FORK	138.00	138.00	3	8.30	0	1	795 ACSR	
61	0138 SOFT SHELL	BEAVER CREEK	138.00	138.00	3	1.40	0	2	1590 ACSR	
62	0138 SOFT SHELL	SPICEWOOD	138.00	138.00	3	1.40	0	2	1590 ACSR	
63		BETSY LANE	138.00	138.00	3	0.10	0	1	795 ACSR	

	0139 MORGAN FORK									
64	0139 MORGAN FORK	BEAVER CREEK	138.00	138.00	3	0.10	0	1	795 ACSR	
65	0140 BONNYMAN	SOFT SHELL	138.00	138.00	3	0.88	0	2	1590 KCM ACSS	
66	0140 BONNYMAN	SOFT SHELL	138.00	138.00	1	19.15	0	1	1590 KCM ACSS	
67	0154 Racoon Extension		138.00	138.00	1	0.20	0	2	1033.5KCM ACSR	
68	0119 BETSY LAYNE	ALLEN	46.00	138.00	1	5.89	0	1	795KCM ACSR	
69	0119 BETSY LAYNE	ALLEN	46.00	138.00	3	0.22	0	2	1033.5KCM ACSR	
70	0119 BETSY LAYNE	ALLEN	46.00	138.00	1	0.33	0	2	1033.5KCM ACSR	
71	0142 STANVILLE EXTENSION		138.00	138.00	1	0.42	0	1	1033.5KCM ACSR	
72	LINES < 132KV		69.00	69.00		593.58	6	0		
73	Line cost and expense are	not available by individual								36,3
74	transmission line	Total shown in Column j - p								
36	TOTAL					1,284.42	40.00	78		36,347

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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 o
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other cha

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)		
	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)	Pol Tow an Fixtu (n
1	0154 Raccoon Extension		0.20	1	1.00	2	2	1,034	ACSR		138.00		921
44	TOTAL		0		1	2	2						921

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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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 cha be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattend 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 capa
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole owne equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other tha name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affecte 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)	Nu Tra
1	ALLEN (KP) - KY	Distribution		46.00	0.00	0.00	0.00		
2	ALLEN (KP) - KY	Distribution		46.00	12.00		6.25	1	
3	ASHLAND - KY	Distribution		69.00	0.00	0.00	0.00		
4	ASHLAND - KY	Distribution		69.00	12.00		22.40	1	
5	BAKER 765KV - KY	Transmission		765.00	345.00	34.50	1500.00	3	
6	BAKER 765KV - KY	Transmission		69.00	4.00		3.00	0	
7	BAKER 765KV - KY	Transmission		69.00	12.00		2.50	0	
8	BAKER 765KV - KY	Transmission		69.00	12.00		10.50	0	
9	BARRENSHE - KY	Distribution		69.00	12.00		25.00	1	
10	BEAVER CREEK - KY	Transmission		138.00	0.00	0.00	0.00		
11	BEAVER CREEK - KY	Transmission		138.00	0.00	0.00	0.00		
12	BEAVER CREEK - KY	Transmission		138.00	70.50	46.00	90.00	1	
13	BEAVER CREEK - KY	Transmission		138.00	69.00	46.00	90.00	1	
14	BEAVER CREEK - KY	Transmission		138.00	0.00	0.00	0.00		
15	BEAVER CREEK - KY	Transmission		138.00	34.50		30.00	1	
16	BECKHAM - KY	Distribution		138.00	0.00	0.00	0.00		
17	BECKHAM - KY	Distribution		138.00	34.50		30.00	1	
18	BEEFHIDE - KY	Distribution		138.00	34.50		20.00	1	
19	BELFRY - KY	Distribution		46.00	12.00		10.50	1	
20	BELHAVEN - KY	Distribution		138.00	13.09		20.00	1	
21	BELLEFONTE 138KV - KY	Transmission		138.00	13.09		22.40	1	
22	BELLEFONTE 138KV - KY	Transmission		138.00	69.00	34.50	308.00	2	

23	BELLEFONTE 138KV - KY	Transmission		138.00	35.00		45.00	1	
24	BELLEFONTE 69KV - KY	Transmission		69.00	0.00	0.00	0.00		
25	BIG SANDY 138KV - KY	Transmission		138.00	13.09		20.00	1	
26	BIG SANDY 138KV - KY	Transmission		138.00	34.50		20.00	1	
27	BIG SANDY 138KV - KY	Transmission		138.00	69.50	13.20	128.80	1	
28	BLUE GRASS - KY	Distribution		69.00	12.00		10.50	1	
29	BONNYMAN - KY	Transmission		69.00	34.50		30.00	1	
30	BONNYMAN - KY	Transmission		138.00	70.50	13.00	130.00	1	
31	BULAN - KY	Distribution		69.00	12.00		9.38	1	
32	BURDINE - KY	Distribution		46.00	12.00		7.50	1	
33	BURTON - KY	Distribution		46.00	12.00		6.25	1	
34	BUSSEYVILLE - KY	Distribution		138.00	34.50		55.00	2	
35	CEDAR CREEK - KY	Transmission		138.00	69.00	46.00	90.00	1	
36	CEDAR CREEK - KY	Transmission		138.00	34.50		25.00	0	
37	CHADWICK - KY	Transmission		138.00	69.00	34.50	200.00	1	
38	CHAVIES - KY	Distribution		69.00	12.00		3.75	1	
39	CHAVIES - KY	Distribution		69.00	0.00	0.00	0.00		
40	COALTON - KY	Distribution		69.00	12.00		25.00	1	
41	COALTON - KY	Distribution		69.00	0.00	0.00	0.00		
42	COLEMAN - KY	Distribution		69.00	34.50		20.00	1	
43	COLEMAN - KY	Distribution		69.00	12.00		3.75	1	
44	COLLIER - KY	Distribution		69.00	34.00		25.00	1	
45	COLLIER - KY	Distribution		69.00	0.00	0.00	0.00		
46	COMBS - KY	Distribution		69.00	0.00	0.00	0.00		
47	COMBS - KY	Distribution		69.00	12.00		7.50	1	
48	DAISY - KY	Distribution		69.00	0.00	0.00	0.00		
49	DAISY - KY	Distribution		69.00	12.00		4.70	1	
50	DEWEY - KY	Transmission		138.00	34.50		25.00	1	
51	DEWEY - KY	Transmission		138.00	69.00	12.00	90.00	1	
52	DEWEY - KY	Transmission		69.00	0.00	0.00	0.00		
53	DORTON - KY	Transmission		138.00	70.50	46.00	144.00	2	
54	DRAFFIN - KY	Distribution		46.00	12.00		10.50	1	
55	EAST PRESTONSBURG - KY	Distribution		46.00	12.00		20.00	1	
56	ELWOOD (KP) - KY	Distribution		46.00	34.50	6.50	25.00	1	
57	ELWOOD (KP) - KY	Distribution		46.00	0.00	0.00	0.00		
58	ENGLE - KY	Distribution		69.00	34.50		20.00	1	
59	FALCON - KY	Distribution		69.00	46.00		20.00	1	

60	FEDS CREEK - KY	Distribution		69.00	12.00		22.34	1	
61	FISHTRAP - KY	Distribution		69.00	12.00		3.75	1	
62	FLEMING - KY	Transmission		138.00	69.00	46.00	130.00	1	
63	FLEMING - KY	Transmission		69.00	0.00	0.00	0.00		
64	FLEMING - KY	Transmission		69.00	12.00		20.00	1	
65	FORDS BRANCH - KY	Distribution		46.00	34.50	12.00	30.00	1	
66	FORDS BRANCH STEPDOWN - KY	Distribution		34.50	12.00		3.75	1	
67	FORTY SEVENTH STREET - KY	Distribution		69.00	13.09		12.00	1	
68	GARRETT (KP) - KY	Transmission		46.00	12.00		10.50	1	
69	GRAHN - KY	Distribution		69.00	12.00		3.13	1	
70	GRAYS BRANCH - KY	Distribution		69.00	12.00		5.00	1	
71	GRAYSON - KY	Distribution		69.00	12.00		20.00	1	
72	HADDIX - KY	Distribution		69.00	34.50		25.00	1	
73	HADDIX - KY	Distribution		69.00	0.00	0.00	0.00		
74	HATFIELD (KP) - KY	Transmission		138.00	69.00	46.00	60.00	1	
75	HAYWARD - KY	Distribution		69.00	13.09		9.38	1	
76	HAZARD - KY	Transmission		138.00	36.20		30.00	1	
77	HAZARD - KY	Transmission		69.00	0.00	0.00	0.00		
78	HAZARD - KY	Transmission		161.00	70.50	13.09	1842.00	9	
79	HAZARD - KY	Transmission		161.00	138.00	13.09	3684.00	18	
80	HAZARD - KY	Transmission		138.00	69.00	12.00	180.00	2	
81	HAZARD - KY	Transmission		138.00	0.00	0.00	0.00		
82	HAZARD - KY	Transmission		34.50	12.00		9.38	1	
83	HAZARD - KY	Transmission		161.00	138.00	13.09	210.00	0	
84	HENRY CLAY - KY	Distribution		46.00	34.50		30.00	1	
85	HENRY CLAY - KY	Distribution		46.00	0.00	0.00	0.00		
86	HIGHLAND (KP) - KY	Distribution		69.00	0.00	0.00	0.00		
87	HIGHLAND (KP) - KY	Distribution		69.00	13.09		25.00	1	
88	HITCHINS - KY	Distribution		69.00	13.09		25.00	1	
89	HOODS CREEK - KY	Distribution		69.00	12.00		10.50	1	
90	HOWARD COLLINS - KY	Distribution		69.00	12.00		30.50	2	
91	INDEX - KY	Distribution		69.00	12.00		9.40	1	
92	INEZ - KY	Transmission		138.00	69.00	13.09	50.00	1	
93	INEZ - KY	Transmission		69.00	0.00	0.00	0.00		
94	INEZ - KY	Transmission		138.00	0.00	0.00	0.00		
95	JACKSON - KY	Distribution		69.00	12.00		14.50	2	
96	JACKSON - KY	Distribution		69.00	0.00	0.00	0.00		
97	JEFF - KY	Distribution		69.00	36.20		30.00	1	

98	JENKINS - KY	Distribution		69.00	12.00		10.50	1	
99	JOHNS CREEK - KY	Transmission		69.00	0.00	0.00	0.00		
100	JOHNS CREEK - KY	Transmission		138.00	70.50	36.20	54.00	1	
101	JOHNS CREEK - KY	Transmission		138.00	0.00	0.00	0.00		
102	KENWOOD - KY	Distribution		46.00	0.00	0.00	0.00		
103	KENWOOD - KY	Distribution		46.00	12.00		20.00	1	
104	KEYSER - KY	Distribution		69.00	12.00		20.00	1	
105	KIMPER - KY	Distribution		69.00	12.00		9.38	1	
106	LESLIE - KY	Transmission		69.00	0.00	0.00	0.00		
107	LESLIE - KY	Transmission		69.00	34.50		30.00	1	
108	LESLIE - KY	Transmission		161.00	69.00	12.00	90.00	1	
109	LOVELY - KY	Distribution		138.00	34.00		30.00	1	
110	MANSBACH - KY	Distribution		69.00	4.00		9.38	1	
111	MAYKING - KY	Distribution		69.00	12.00		20.00	1	
112	MAYO TRAIL - KY	Distribution		69.00	0.00	69.00	25.00	1	
113	MCKINNEY - KY	Distribution		46.00	34.00		20.00	1	
114	MCKINNEY - KY	Distribution		34.50	12.00		6.67	1	
115	MIDDLE CREEK - KY	Distribution		46.00	12.00		3.75	1	
116	MORGAN FORK - KY	Transmission		138.00	0.00	0.00	0.00		
117	NEW CAMP - KY	Distribution		69.00	12.00		20.00	1	
118	OLIVE HILL - KY	Distribution		69.00	4.00		5.00	1	
119	OLIVE HILL - KY	Distribution		69.00	12.00		7.50	1	
120	PRESTONSBURG - KY	Distribution		46.00	13.09		10.00	1	
121	PRESTONSBURG - KY	Distribution		46.00	0.00	0.00	0.00		
122	PRINCESS - KY	Distribution		69.00	0.00	0.00	0.00		
123	RACELAND - KY	Distribution		69.00	2.40		7.50	1	
124	REEDY COAL - KY	Distribution		69.00	34.00		20.00	1	
125	RUSSELL - KY	Distribution		69.00	12.00		22.40	1	
126	RUSSELL FORK - KY	Distribution		69.00	12.00		3.75	1	
127	SALISBURY (KP) - KY	Distribution		46.00	13.09		20.00	1	
128	SECOND FORK - KY	Distribution		69.00	0.00	0.00	0.00		
129	SECOND FORK - KY	Distribution		69.00	12.00		7.50	1	
130	SHAMROCK - KY	Distribution		69.00	34.50		10.50	1	
131	SIDNEY - KY	Distribution		69.00	12.00		20.00	1	
132	SILOAM - KY	Distribution		69.00	12.00		4.68	1	
133	SLEMP - KY	Distribution		69.00	34.00		20.00	1	
134	SLEMP - KY	Distribution		69.00	34.50		10.50	1	

135	SOFT SHELL - KY	Distribution		138.00	34.50		30.00	1	
136	SOUTH PIKEVILLE - KY	Distribution		69.00	13.09		25.00	1	
137	SOUTH SHORE - KY	Distribution		69.00	13.09		7.50	1	
138	SPRING FORK - KY	Distribution		46.00	7.20		0.83	1	
139	STINNETT - KY	Distribution		161.00	34.00	7.20	14.93	1	
140	STINNETT - KY	Distribution		161.00	34.50	7.20	22.40	0	
141	STINNETT - KY	Distribution		161.00	34.50	7.20	22.40	1	
142	STONE - KY	Transmission		138.00	70.50	46.00	90.00	1	
143	TENTH STREET - KY	Distribution		69.00	13.09		25.00	1	
144	THELMA - KY	Transmission		46.00	0.00	0.00	0.00		
145	THELMA - KY	Transmission		138.00	0.00	0.00	0.00		
146	THELMA - KY	Transmission		138.00	69.00	12.00	90.00	1	
147	THELMA - KY	Transmission		138.00	69.00	46.00	70.00	1	
148	TOM WATKINS - KY	Distribution		69.00	12.00		10.50	1	
149	TOPMOST - KY	Distribution		138.00	13.09		20.00	1	
150	VICCO - KY	Distribution		138.00	34.50		30.00	1	
151	WEEKSBURY - KY	Distribution		69.00	12.00		6.25	1	
152	WEST PAINTSVILLE - KY	Distribution		69.00	12.00		25.00	1	
153	WHITESBURG - KY	Distribution		69.00	0.00	0.00	0.00		
154	WHITESBURG - KY	Distribution		69.00	12.00		35.50	2	
155	WORTHINGTON - KY	Distribution		69.00	12.00		1.50	1	
156	TotalTransmissionSubstationMember								
157	Total								

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

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ 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	1,641,320
3	Corp Safety & Health	AEPSC	920,923	645,829
4	Infrastructure Ops & Support	AEPSC	920, 923	318,472
5	Administrative and General Expenses - Operation	AEPSC	920,921,922,923,925,926,928,930.1,930.2,931	958,866
6	Audit Services	AEPSC	[(a)] 920, 923	410,917
7	Environmental Services	AEPSC	920, 923	249,048
8	Bus Ops & Perf Assurance	AEPSC	920,923	436,968
9	Customer Accounts Expenses	AEPSC	901-905	3,714,170
10	Customer Support	AEPSC	920, 923	369,233
11	Central Machine Shop	APCo	[(b)] 107,108,500,506,512,513,514,920	972,875
12	Corporate Accounting	AEPSC	920,923	910,305
13	Physical & Cyber Security	AEPSC	920,923	393,944
14	Construction Services	AEPSC	107,108	30,634,909
15	Corporate Communications	AEPSC	920,923	384,524
16	Strategy & Transformation	AEPSC	920,923	346,098
17	Construction Services	I&M	107,108	356,583
18	Corporate Planning & Budgeting	AEPSC	920,923	634,576
19	Tax Services	AEPSC	920,923	353,375
20	Construction Services	OPCO	107,108	584,810
21	Distribution Expenses - Maintenance	AEPSC	[(c)] 590-598	766,066
22	Grid Solutions	AEPSC	920,923	314,248
23		APCO	935	291,189

	Administrative and General Expenses - Maintenance			
24	Distribution Expenses - Operation	AEPSC	[d] 580,582,583,584,586,588	961,063
25	Information Technology	AEPSC	920,923	2,657,687
26	Corporate Human Resources	AEPSC	920, 923	1,123,599
27	Fuel & Storeroom Service	AEG	152	446,773
28	Legal GC/Administration	AEPSC	920,923	2,240,286
29	Factored Customer A/R Expense	AEP Credit	426.5	1,728,117
30	Real Estate & Workplace Svcs	AEPSC	920,923	968,865
31	Fuel & Storeroom Services	AEPSC	152,154,163	3,327,569
32	Regulatory Services	AEPSC	920,923	408,706
33	Distribution Expenses - Maintenance	I&M	593,595,592	365,227
34	Materials and Supplies	APCo	[e] 107,108,154,163,511-514,570,571,586,588,595,598,930	310,746
35	Materials and Supplies	OPCo	[f] [g] 107,108,184,513,570,571,935.992.993	2,564,009
36	Transmission Expenses - Operation	AEPSC	560,561.2,561.4,561.5,562,563,564,566,920,923	4,042,749
37	Other Power Supply Expense	AEPSC	556-557	1,236,650
38	Treasury & Risk	AEPSC	920,923	541,935
39	Research and Other Services	AEPSC	183,186,188	1,433,976
40	Urea	APCo	154	1,367,952
41	Civil & Political Activities and Other Svcs	AEPSC	426.1,426.3,426.4,426.5	411,363
42	Steam Power Generation - Maintenance	AEPSC	[h] 510-514	4,032,794
43	Construction Services	APCo	107,108	583,838
44	Steam Power Generation - Operation	AEPSC	[i] 500,501,502,505,506	5,797,856
45	Distribution Expenses - Maintenance	OPCO	593,595	589,357
46	Transmission Expenses - Maintenance	AEPSC	[j] 568,590-592,570-573	2,331,450
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Building and Property Leases	AEPSC	4540	1,093,503
22	Fleet and Vehicle Charges	AEPSC	Various	1,287,125
23	Materials and Supplies	APCo	[k] 154	251,959

24	O&M Services for Jointly Owned Facility - Mitchell	WPCo	107,108,154,186,401,408,421,426,500,501,502,505,506,510-514,557,920-923,925,926,928,930,931,935	49,549,381
25	Urea	APCo	(l) 1540	964,517
26	Urea	WPCo	1540	611,778
27	Use of Jointly Owned Facility	KYTCo	454	457,637
42				

Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/06/2022	Year/Period of Report End of: 2021/ Q4

FOOTNOTE DATA

(a) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
920,921,922,923,925,926,928,930.1,930.2,931
(b) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
107,108,500,506,512,513,514,920
(c) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
590-598
(d) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
580,582,583,584,586,588
(e) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
107,108,154,163,511-514,570,571,586,588,595,598,930
(f) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
560,561.2,561.4,561.5,562,563,564,566,920,923
(g) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
107,108,184,513,570,571,935
(h) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
426.1,426.3,426.4,426.5
(i) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
500,501,502,505,506
(j) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
568,569,569.1,569.2,569.3,570,571,572,573
(k) 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.
(l) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
107,108,154,186,401,408,421,426,500,501,502,505,506,510-514,557,920-923,925,926,928,930,931,935

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