COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Certain Regulatory And Accounting Treatments; and (4) All Other Required Approvals And Relief	))))))	Case No. 2025-00257

SECTION II – VOLUME 1 OF 5

FILING REQUIREMENTS AND EXHIBITS A THROUGH R

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Kentucky Power Company
KPSC Case No. 2025-00257
Historical Test Period Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
KRS 278.180
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Changes in rates, how made.

(1) Except as provided in subsection (2) of this section, no change shall be made by any utility in any rate except upon thirty (30) days' notice to the commission, stating plainly the changes proposed to be made and the time when the changed rates will go into effect. However, the commission may, in its discretion, based upon a showing of good cause in any case, shorten the notice period from thirty (30) days to a period of not less than twenty (20) days. The commission may order a rate change only after giving an identical notice to the utility. The commission may order the utility to give notice of its proposed rate increase to that utility's customers in the manner set forth in its regulations.

(2) The commission, upon application of any utility, may prescribe a less time within which a reduction of rates may be made.

Response:

Kentucky Power Company ("Kentucky Power" or "Company") has complied with the requirements established in KRS 278.180. A copy of the required Statutory Notice is attached as Exhibit 1 to Section I of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
KRS 278.2205 (6)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

The CAM shall be filed as part of the initial filing requirement in a proceeding involving an application for an adjustment in rates pursuant to KRS 278.190.

Response:

The Company's Cost Allocation Manual is attached as Exhibit A to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 4(1)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:
Address of the Commission

All communications shall be addressed to: Public Service Commission, 211 Sower Boulevard, Post Office Box 615, Frankfort, Kentucky 40602.

Response:

Kentucky Power is filing its application using electronic filing procedures pursuant to the Commission's July 22, 2021, Order in Case No. 2020-00085. The Company filed its Notice of Election to use Electronic Filing Procedures Form on July 29, 2025.

To the extent requested, Kentucky Power will provide any written communications pursuant to 807 KAR 5:001 Section 4(1).

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 4(2)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Case Numbers and Styles

Each case shall receive a number and a style descriptive of the subject matter. The number and style shall be placed on each subsequent paper filed in the case.

Response:

Kentucky Power will comply with the requirements established in 807 KAR 5:001 Section 4(2).

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 4(3)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Signing Papers

(a) A paper shall be signed by the submitting party or attorney and shall include the name, address, telephone number, facsimile number, and electronic mail address, if any, of the attorney of record or submitting party.

(b) A paper shall be verified or under oath if required by statute, administrative regulation, or order of the commission.

Response:

Kentucky Power will comply with the requirements established in 807 KAR 5:001 Section 4(3).

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 4(4)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

A person shall not file a paper on behalf of another person, or otherwise represent another person, unless the person is an attorney licensed to practice law in Kentucky or an attorney who has complied with SCR 3.030(2). An attorney who is not licensed to practice law in Kentucky shall present evidence of his or her compliance with SCR 3.030(2) if appearing before the commission.

Response:

Kentucky Power will comply with the requirements established in 807 KAR 5:001 Section 4(4).

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 4(8)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Service.

(a) Unless the commission orders service upon a party and the party's attorney, service shall be made upon the party's attorney if the party is represented by an attorney.

(b) Service upon an attorney or upon a party by the commission shall be made by sending a copy by electronic mail to the electronic mail address listed on papers that the attorney or party has submitted in the case. A paper that is served via electronic mail shall comply with Section 8(4) of this administrative regulation and shall include the sending of an electronic mail message that contains an electronic version of the commission order or a hyperlink that enables the recipient to access, view, and download an electronic copy of the commission order from the commission's Web site.

(c) If good cause exists, and upon the filing of a motion by a party to excuse a party from receiving service by electronic mail from the commission, the commission shall order service of papers on the party to be made in accordance with paragraph (d)1. or 2. of this subsection.

(d) Service upon an attorney or upon a party by the parties in a case shall be made by:

1. Delivering a copy to the attorney or party;
2. Mailing a copy by United States mail or other recognized mail carrier to the attorney or party at the last known address; or
3. Sending a copy by electronic mail to the electronic mail address listed on papers that the attorney or party has submitted in the case. A paper that is served via electronic mail shall comply with Section 8(4) of this administrative regulation.

(e) Service shall be complete upon mailing or electronic transmission. If a serving party learns that the mailing or electronic transmission did not reach the person to be served, the serving party shall take reasonable steps to immediately re-serve

the party to be served, unless service is refused, in which case the serving party shall not be required to take additional action.

Response:

Kentucky Power will comply with the requirements established in 807 KAR 5:001 Section 4(8).

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 4(9)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Filing.

(a) Unless electronic filing procedures established in Section 8 of this administrative regulation are used, a paper shall not be deemed filed with the commission until the paper:

1. Is physically received by the executive director at the commission's offices during the commission's official business hours; and
2. Meets all applicable requirements of KRS Chapter 278 and KAR Title 807.

(b) The executive director shall endorse upon each paper or document accepted for filing the date of its filing. The endorsement shall constitute the filing of the paper or document.

Response:

Kentucky Power is filing its application using electronic filing procedures pursuant to the Commission's July 22, 2021, Order in Case No. 2020-00085. The Company filed its Notice of Election to use Electronic Filing Procedures Form on July 29, 2025.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 4(10)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Privacy protection for filings.

(a) If a person files a paper containing personal information, the person shall encrypt or redact the paper so that personal information cannot be read. Personal information shall include a business name; an individual's first name or first initial and last name; personal mark; or unique biometric or genetic print or image, in combination with one (1) or more of the following data elements:

1. The digits of a Social Security number or taxpayer identification number;
2. The month and date of an individual's birth;
3. The digits of an account number, credit card number, or debit card number that, in combination with any required security code, access code, or password, would permit access to an account;
4. A driver's license number, state identification card number, or other individual identification number issued by any agency;
5. A passport number or other identification number issued by the United States government;
6. "Individually identifiable health information" as defined by 45 C.F.R. 160.103, except for education records covered by the Family Educational Rights and Privacy Act, as amended, 20 U.S.C. 1232g; or
7. The address, phone number, or email address of an individual who is not a party and has not requested to be a party.

(b) To redact the paper, the filing party shall replace the identifiers with neutral placeholders or cover the identifiers with an indelible mark that so obscures the identifiers that the identifiers cannot be read.

(c) The responsibility to review for compliance with this section and redact a paper shall rest with the party that files the paper.

Response:

Kentucky Power will comply with the requirements established in 807 KAR 5:001 Section 4(10).

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 6
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

(1) Except as provided in Section 8 of this administrative regulation, all papers filed in a case shall contain proof of the date and manner of service of the papers on all parties.

(2) Proof shall be made by certificate of the filer's attorney, by affidavit of the person who served the papers, or by a comparable proof.

(3) The certificate or affidavit shall identify by name the person served and the date and method of service.

(4) Proof of electronic service shall state the electronic notification address of the person served.

Response:

Kentucky Power will comply with the requirements established in 807 KAR 5:001 Section 6.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 7(1)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Unless the commission orders otherwise or the electronic filing procedures established in Section 8 of this administrative regulation are used, if a paper is filed with the commission, an original unbound and ten (10) additional copies in paper medium shall be filed.

Response:

Kentucky Power is filing its application using electronic filing procedures pursuant to the Commission's July 22, 2021, Order in Case No. 2020-00085. The Company filed its Notice of Election to use Electronic Filing Procedures Form on July 29, 2025.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 7(2)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Each paper filed with the commission shall conform to the requirements established in this subsection.

(a) Form. Each filing shall be printed or typewritten, double spaced, and on one (1) side of the page only.

(b) Size. Each filing shall be on eight and one-half (8 1/2) inches by eleven (11) inches paper.

(c) Font. Each filing shall be in type no smaller than twelve (12) point, except footnotes, which may be in type no smaller than ten (10) point.

Response:

Kentucky Power will comply with the requirements established in 807 KAR 5:001 Section 7(2).

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 7(3)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Except as provided for in Section 8 of this administrative regulation, a filing made with the commission outside its business hours shall be considered as filed on the commission's next business day.

Response:

Kentucky Power is filing its application using electronic filing procedures pursuant to the Commission's July 22, 2021, Order in Case No. 2020-00085. The Company filed its Notice of Election to use Electronic Filing Procedures Form on July 29, 2025.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 8
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Upon an applicant's timely election of the use of electronic filing procedures or upon order of the commission in a case that the commission has initiated on its own motion, the procedures established in this section shall be used in lieu of other filing procedures established in this administrative regulation.

Response:

Kentucky Power is filing its application using electronic filing procedures pursuant to the Commission's July 22, 2021, Order in Case No. 2020-00085. The Company filed its Notice of Election to use Electronic Filing Procedures Form on July 29, 2025. Kentucky Power will comply with the requirements established in 807 KAR 5:001, Section 8.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 12(1)
Sponsoring Witnesses: Franz D. Messner, Brian C. Ciborek, David A. Hodgson

Filing Requirement:

If this administrative regulation requires that a financial exhibit be annexed to the application, the exhibit shall:

(a) For a utility that had $5,000,000 or more in gross annual revenue in the immediate past calendar year, cover operations for a twelve (12) month period, the period ending not more than ninety (90) days prior to the date the application is filed; or

(b) For a utility that had less than $5,000,000 in gross annual revenue in the immediate past calendar year, comply with paragraph (a) of this subsection or cover operations for the twelve (12) month period contained in the utility's most recent annual report on file with the commission, and contain a statement that:
1. Material changes have not occurred since the end of that twelve (12) month period; or
2. Identifies all material changes that have occurred since the end of that twelve (12) month period.

Response:

The required financial exhibit complies with 807 KAR 5:001, Section 12(1) and is included as Section IV of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 12(2)(a)
Sponsoring Witness: Franz D. Messner

Filing Requirement:

The exhibit shall disclose the following information in the order indicated:

(a) The amount and kinds of stock authorized;

Response:

The required information is included on page 1 of Section IV of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 12(2)(b)
Sponsoring Witness: Franz D. Messner

Filing Requirement:

The amount and kinds of stock issued and outstanding;

Response:

The required information is included on page 1 of Section IV of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 12(2)(c)
Sponsoring Witness: Franz D. Messner

Filing Requirement:

Terms of preference of preferred stock, cumulative or participating, or on dividends or assets or otherwise;

Response:

The required information is included on page 1 of Section IV of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 12(2)(d)
Sponsoring Witness: Franz D. Messner

Filing Requirement:

A brief description of each mortgage on property of applicant, giving date of execution, name of mortgagor, name of mortgagee or trustee, amount of indebtedness authorized to be secured, and the amount of indebtedness actually secured, together with sinking fund provisions, if applicable;

Response:

The required information is included on page 1 of Section IV of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 12(2)(e)
Sponsoring Witness: Franz D. Messner

Filing Requirement:

The amount of bonds authorized and amount issued, giving the name of the public utility that issued the same, describing each class separately and giving the date of issue, face value, rate of interest, date of maturity, and how secured, together with amount of interest paid during the last fiscal year;

Response:

The required information is included on page 1 of Section IV of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 12(2)(f)
Sponsoring Witness: Franz D. Messner

Filing Requirement:

Each note outstanding, giving date of issue, amount, date of maturity, rate of interest, in whose favor, together with amount of interest paid during the last fiscal year;

Response:

The required information is included on page 1 of Section IV of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 12(2)(g)
Sponsoring Witness: Franz D. Messner

Filing Requirement:

Other indebtedness, giving same by classes and describing security, if any, with a brief statement of the devolution or assumption of a portion of the indebtedness upon or by person or corporation if the original liability has been transferred, together with amount of interest paid during the last fiscal year;

Response:

The required information is included on page 2 of Section IV of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 12(2)(h)
Sponsoring Witness: Franz D. Messner

Filing Requirement:

The rate and amount of dividends paid during the five (5) previous fiscal years, and the amount of capital stock on which dividends were paid each year; and;

Response:

The required information is included on page 2 of Section IV of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 12(2)(i)
Sponsoring Witness: Brian C. Ciborek

Filing Requirement:

A detailed income statement and balance sheet.

Response:

The required information is included on pages 3, 4, and 7 of Section IV of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 14(1)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Each application shall state the full name, mailing address, and electronic mail address of the applicant, and shall contain fully the facts on which the application is based, with a request for the order, authorization, permission, or certificate desired and a reference to the particular law requiring or providing for the information.

Response:

The full name, mailing address, and electronic mail address of the applicant:

Kentucky Power Company
1645 Winchester Avenue
Ashland, KY 41101
Kentucky_Regulatory_Services@aep.com

is included in Section I of the Company's Application. The Application, supporting testimony, and exhibits fully comply with the requirements of 807 KAR 5:001 Section 14(1).

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 14(2)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

If a corporation, the applicant shall identify in the application the state in which it is incorporated and the date of its incorporation, attest that it is currently in good standing in the state in which it is incorporated, and, if it is not a Kentucky corporation, state if it is authorized to transact business in Kentucky.

Response:

Information related to Kentucky Power's incorporation is contained in paragraph 2 and footnote 1 of Section I of its Application. Kentucky Power's Certificate of Existence dated August 25, 2025, as certified by the Commonwealth of Kentucky's Secretary of State, is included as Exhibit B to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 14(3)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

If a limited liability company, the applicant shall identify in the application the state in which it is organized and the date on which it was organized, attest that it is in good standing in the state in which it is organized, and, if it is not a Kentucky limited liability company, state if it is authorized to transact business in Kentucky.

Response:

Kentucky Power is not a limited liability company.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 14(4)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

If the applicant is a limited partnership, a certified copy of its limited partnership agreement and all amendments, if any, shall be annexed to the application, or a written statement attesting that its partnership agreement and all amendments have been filed with the commission in a prior proceeding and referencing the case number of the prior proceeding.

Response:

Kentucky Power is not a limited partnership.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(1)(a)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Each application requesting a general adjustment of existing rates shall:

(a) Be supported by:

1. A twelve (12) month historical test period that may include adjustments for known and measurable changes; or

2. A fully forecasted test period;

Response:

Kentucky Power's application for a general adjustment to its existing rates is supported by a twelve-month historical test period ended May 31, 2025, with adjustments for known and measurable changes.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(1)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

A statement of the reason the adjustment is required.

Response:

The reasons supporting the required adjustment in rates are set forth in the Company's Application and in the testimony of the Company's witnesses.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(2)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that a certificate is not necessary.

Response:

Kentucky Power Company transacts business using the following three assumed names:

1. Kentucky Power

2. AEP Kentucky Power

3. American Electric Power

Certified copies of the Company's certificates of assumed name dated February 18, 2021 and November 12, 2021, respectively are included as Exhibit C to Section II of the Application.

Kentucky Power Cost Recovery LLC ("Cost Recovery") is a separate entity formed in Delaware and registered to do business in Kentucky. Cost Recovery is a wholly owned subsidiary of Kentucky Power with Kentucky Power owning 100% of the outstanding membership interests in and to Cost Recovery. In Kentucky, any proposed assumed name must be distinguishable upon the records of the Secretary of State from any other name filed and on record with the Secretary of State. Thus, Kentucky Power cannot file an assumed name certificate with the Kentucky Secretary of State for, nor do business as, "Kentucky Power Cost Recovery LLC" because Cost Recovery is already a separate entity registered in Kentucky.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(3)
Sponsoring Witness: Stevi N. Cobern

Filing Requirement:

New or revised tariff sheets, if applicable in a format that complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed;

Response:

The new and revised tariff sheets in a format that complies with 807 KAR 5:011 are included as Exhibit D to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(4)
Sponsoring Witness: Stevi N. Cobern

Filing Requirement:

New or revised tariff sheets, if applicable, identified in compliance with 807 KAR 5:011, shown either by providing:

a. The present and proposed tariffs in comparative form on the same sheet side by side or on facing sheets side by side; or

b. A copy of the present tariff indicating proposed additions by italicized inserts or underscoring and striking over proposed deletions;

Response:

New and revised tariff sheets in a format that complies with 807 KAR 5:011 marked to show changes from the existing tariff sheets are included as Exhibit E to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(1)(b)(5)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

A statement that notice has been given in compliance with Section 17 of this administrative regulation with a copy of the notice;

Response:

The Company's Certification of Compliance with Notice and Posting Requirements is included in Exhibit F to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(2)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Notice of Intent

A utility with gross annual revenues greater than $5,000,000 shall notify the commission in writing of its intent to file a rate application at least thirty (30) days, but not more than sixty (60) days, prior to filing its application.

(a) The notice of intent shall state if the rate application will be supported by a historical test period or a fully forecasted test period.

(b) Upon filing the notice of intent, an application may be made to the commission for permission to use an abbreviated form of newspaper notice of proposed rate increases provided the notice includes a coupon that may be used to obtain a copy from the applicant of the full schedule of increases or rate changes.

(c) Upon filing the notice of intent with the commission, the applicant shall mail to the Attorney General's Office of Rate Intervention a copy of the notice of intent or send by electronic mail in a portable document format, to rateintervention@ag.ky.gov.

Response:

The Company's Notice of Intent to File for An Adjustment in Electric Rates was filed with the Commission on July 29, 2025. A copy of the Notice of Intent is attached as Exhibit G to Section II of the Application.

In conformity with 807 KAR 5:001, Section 16(2)(c), the Company also provided notice to the Attorney General July 29, 2025, by electronic mail to the Attorney General's Office of Rate Intervention, a copy of which is also included in Exhibit G to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(a)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Each application supported by a historical test period shall include the following information or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(a) A complete description and quantified explanation for all proposed adjustments with proper support for proposed changes in price or activity levels, if applicable, and other factors that may affect the adjustment;

Response:

The complete descriptions and quantified explanations for all proposed adjustments, with proper support for any proposed changes in price or activity levels, and any other factors, are provided in Section III and Section V, Exhibit 2 of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(b)
Sponsoring Witness: Cynthia G. Wiseman

Filing Requirement:

If the utility has gross annual revenues greater than $5,000,000, the written testimony of each witness the utility proposes to use to support its application;

Response:

Please refer to the testimony and exhibits of the following persons included in Section III of the Application:

Cynthia G. Wiseman
Jeffrey D. Newcomb
Tanner S. Wolffram
Michele Ross
Robert A. Jessee
Stevi N. Cobern
John D. Cullop
Jaclyn N. Cost
Nicole M. Coon
Michael M. Spaeth
Franz D. Messner
Adrien M. McKenzie
Brian C. Ciborek
David A. Hodgson
Andrew R. Carlin
Clinton M. Stutler
Timothy Lyons
John Wolfram
John Spanos

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(c)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

If the utility has gross annual revenues less than $5,000,000 the written testimony of each witness the utility proposes to use to support its application or a statement that the utility does not plan to submit written testimony;

Response:

Not applicable.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(d)
Sponsoring Witness: Jeffrey D. Newcomb

Filing Requirement:

A statement estimating the effect that each new rate will have upon the revenues of the utility including, at minimum, the total amount of revenues resulting from the increase or decrease and the percentage of the increase or decrease;

Response:

The required statement is presented in the Section I of the Application at paragraph 16, in Section V, Exhibit 1 of the Application, and in the testimony of Company Witness Newcomb at page 5.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(e)
Sponsoring Witness: Michael M. Spaeth

Filing Requirement:

If the utility provides electric, gas, water, or sewer service, the effect upon the average bill for each customer classification to which the proposed rate change will apply;

Response:

The required information is provided in Exhibit H to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(f)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

If the utility is an incumbent local exchange company, the effect upon the average bill for each customer class for the proposed rate change in basic local service;

Response:

Not Applicable.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(g)
Sponsoring Witness: Michael M. Spaeth

Filing Requirement:

A detailed analysis of customers' bills whereby revenues from the present and proposed rates can be readily determined for each customer class;

Response:

The required analysis of customers' bills is included in Exhibit I to Section II of the Application. Additionally, a chart showing revenues from the present and proposed rates for each customer class is included as Exhibit J to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(h)
Sponsoring Witness: Jaclyn N. Cost

Filing Requirement:

A summary of the utility's determination of its revenue requirements based on return on net investment rate base, return on capitalization, interest coverage, debt service coverage, or operating ratio, with supporting schedules;

Response:

The required information is provided in Section V, Exhibit 1, Schedules 1, 2, and 4 of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(i)
Sponsoring Witness: Jaclyn N. Cost

Filing Requirement:

A reconciliation of the rate base and capital used to determine its revenue requirements;

Response:

The reconciliation of the rate base and capital used to determine Kentucky Power's revenue requirement is included as Exhibit K to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(j)
Sponsoring Witness: Brian C. Ciborek

Filing Requirement:

A current chart of accounts if more detailed than the Uniform System of Accounts;

Response:

The current chart of accounts is included as Exhibit L to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(k)
Sponsoring Witness: Brian C. Ciborek

Filing Requirement:

The independent auditor's annual opinion report, with written communication from the independent auditor to the utility, if applicable, which indicates the existence of a material weakness in the utility's internal controls;

Response:

A copy of the independent auditor's annual opinion report is included as Exhibit M to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(l)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

The most recent Federal Energy Regulatory Commission or Federal Communication Commission audit reports;

Response:

The most recent Federal Energy Regulatory Commission audit report is included as Exhibit N to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(m)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

The most recent FERC Financial Report Form No. 1, FERC Financial Report Form No. 2, or Public Service Commission Form T (telephone);

Response:

Please refer to Exhibit O of Section II of the Application for Kentucky Power Company's FERC Form No. 1 for the year ended December 31, 2024.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(n)
Sponsoring Witness: John Spanos & Tanner S. Wolffram

Filing Requirement:

A summary of the utility's latest depreciation study with schedules by major plant accounts, except that telecommunications utilities that have adopted the commission's average depreciation rates shall provide a schedule that identifies the current and test period depreciation rates used by major plant accounts. If the required information has been filed in another commission case, a reference to that case's number shall be sufficient;

Response:

A summary of the Company's most recent depreciation study with schedules by major plant accounts, along with a copy of the study itself, is contained in the testimony and exhibits of Company Witness Spanos.

Company Witness Spanos's testimony and exhibits set forth new depreciation rates including for the Mitchell Plant; however, as explained in the testimony of Company Witness Wolffram, the Company is not proposing to update its depreciation rates for the Mitchell Plant in this case.

Therefore, current Mitchell Plant depreciation rates were approved to be updated as part of a settlement in Case No. 2017-00179, and the last depreciation study performed for the Mitchell Plant was filed in Case No. 2014-00396 with the Direct Testimony of David A. Davis and Exhibit DAD-2.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(o)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

A list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and work papers associated with the filing of the utility's application. This list shall include:
1. Each software, program, or model;
2. What the software, program, or model was used for;
3. The supplier of each software, program, or model;
4. A brief description of the software, program, or model; and
5. The specifications for the computer hardware and the operating system required to run the program.

Response:

The software used includes the following:

- **Powerplan** is AEP's system of record for capital work orders, capital assets, and the depreciation associated with those capital assets. Most of the work orders and status updates interface into Powerplan from feeder systems such as Maximo or Storms. As work orders are placed in service, assets are created and tracked in Powerplan until they are retired. Depreciation rate information is often entered based on the information received for Accounting Policy and Research and regulatory Accounting. Month end closing processes within Powerplan generate journal entries which are passed to PeopleSoft and feed the general ledger. The current version of the Powerplan version is 2022.2.0.0. The database version is Oracle 19 and resides on UNIX AIX servers. The Powerplan application runs on Windows 2019 Standard Citrix servers and is launched from the Citrix ->Apps tab.

- **PowerTracker** is used to perform the settlement function of economically allocating generation and purchase resources to off-system sales transactions. It provides input to the monthly accounting and fuel clause reporting functions. PowerTracker is a Java application supplied by Integ Enterprise Consulting, Inc. located in Newark, New Jersey. The current version of the application is ptrk.1.14.5-b49-3fc7c14. The application runs in a WebLogic version 12.1.2.0.0 environment. It is a multi-node environment consisting of two servers. The

servers are HP ProLiant model DL580 Gen8 running the Linux Red Hat v6.5 Operating System with 11,913 MB RAM. Additionally, the servers run virtualizing software manufactured by VMware, Inc. The model is VMware Virtual Platform. The database utilized by the application is Oracle version 11.2.0.3.0. The database runs on anIBM 9119-MHE server with 40,960 MB of RAM. Operating system is AIX 7.1.0.0. with VMware Virtual Platform virtualizing software.

- **GADS in SAP Business Objects (GADS)** is a web-based, customizable application that gives energy service providers a way to gather statistical generation data from a variety of sources. Upon collection, all data is validated using NERC Level 1 and Level 2 diagnostics. Once validated, the data is used for several purposes, including internal reporting - for example, in the Station Performance and Generating Outage Rate Program. The product also incorporates capacity verification testing and commercial availability. GADS is a Java application supplied by Integ Enterprise Consulting, Inc. located in Newark, New Jersey. The application runs in a WebLogic version 12.1.2.0.0 environment. It is a multi-node environment consisting of three servers. The servers are HP ProLiant Model DL580 Gen8 running Linux Red Hat 6.2 operating system with 37,161 MB of RAM. Additionally, the server is running virtualizing software manufactured by VMware, Inc. The model is VMware Virtual Platform. The database utilized by the application is Oracle version 11.2.0.3.0. The database runs on an IBM 9119-MHE server with 98,304 MB of RAM. The operating system is AIX 7.1.0.0.

- **MACSS (Marketing Accounting Customer Service System)** is an in-house software system developed for the use of customer data and designed to facilitate the sale and reporting of electric service and equipment. MACSS is a COBOL-based program that is used to access, update, and create customer data for billing, meter, and electric infrastructure for AEP. MACSS has many functions, including general system, service order, marketing, credit and collection, billing, database, and system interface functions. Mainframe and DB2 operating systems are required.

- **PeopleSoft General Ledger** software is a vendor product from Oracle Corporation, Redwood Shores, California. Kentucky Power is using version 9.2 of this software. The software runs off a UNIX AIX server, using an Oracle 19c database. The application can be accessed through Web Browser and Windows client for query reporting.

- **The UIPlanner** is developed by UI Solutions Group. It is an automated tool that will enhance Regulatory Services ability to perform rate design analysis and reporting across all jurisdictions. This solution will allow Regulatory Services to model all current and proposed tariffs performing what-if / scenario analysis as necessary. The computer workstations that access this application run on Windows 10 or higher operating system and require a minimum of 16 GB of memory and 1.73 GHz processor. There are multiple application servers on ProLiant BL660c Gen9 machines running Linux Red Hat 7.9 with 2TB of ram. It uses an Oracle 19c database, running on an Exadata platform.

- **Comtrac (Commodity Tracking) software is a vendor product from FusionSoft, LLC. The** Fuel Accounting team is currently using version 7.12.13.3.4. The Comtrac application is the system of record for coal, fuel oil, and most consumables and helps manage the life-cycle of those commodities, including managing contracts, shipments, sample quality, inventory, and accounting. The Fuel Accounting team (1) records the generated receipts, consumption and accruals from information obtained from Comtrac, into the PeopleSoft General Ledger and (2) pays invoices associated with the receipts of fuel and consumables. The computer workstations that access this application run on Windows 7 operating system, and typically have 8 GB of memory and a 2.5 GHz processor.

- **Aligne,** a vendor software product from Fidelity Information Services. The AEP Energy Settlements team is currently using version 3.0.4.5. The Aligne application is the system of record for natural gas activity including transactional information, inventory, receipts, and consumption. It provides support for the settlement data capture and creation of the information used by Fuel Accounting for entries into the PeopleSoft General Ledger. The computer workstations that access this application run on Windows 10 operating system, and typically have 16 GB of memory and 2.6 GHz processor.

- **Microsoft Suite (Word, Excel, PowerPoint)** These applications were used to prepare spreadsheet documents, word processors, and presentations utilized in this proceeding. The program runs on laptop and desktop computers with 1 GB of RAM using a Microsoft Windows 10 or 11 operating system.

- **ODS (**Online Data Store HOIS/DOVS Archive). This is a browser interface used to search and view outage records. The current limit is 5000 rows. This web page was created by AEP and is managed by internal IT personnel.

- **Distribution Outage Validation System (DOVS) -** Version 5.0.42.2. The DOVS application is used to view, edit, add, and store outage data records. This application was created by AEP and is managed by internal IT personnel.

- **Adobe** is used to view documents without change in how the document looks on the screen or in print. It converts documents into pdf format which can be read without the need of the application program which the document was originally created. This software can be run on most personal computers with Windows 10 or higher.

- **PDF Xchange** is used to view documents without change in how the document looks on the screen or in print. It converts documents into pdf format which can be read without the need of the application program which the document was originally created. PDF-XChange Editor supports all current versions of MS Windows operating systems, and previous versions that are maintained with service updates from Microsoft, including Windows 11.

- **COGNOS** is an IBM Enterprise reporting tool used companywide for reporting, querying and analyzing data from AEP source systems. The Company is using COGNOS version 11.2.4. Cognos runs on multiple application servers (eight in total). These servers are X86 Linux servers on Linux (RHEL 8.1) and consists of 224 GB RAM and 8 CPU's each distributed across both NADS and GDC. It used Oracle 19c database as a content store to write the metadata.

- **MarketPay** by Payscale is a compensation survey data aggregator that supports merit and structure modeling and provides a report writer and job pricing wizard. This software stores, organizes and links multiple surveys and data cuts, AEP system compensation data and AEP system job matches that facilitates the market pricing of internal positions. Data was pulled from MarketPay to provide comparisons of market survey information to AEP's compensation for matched jobs aged to the applicable date with market percentiles for base pay, target and actual incentive compensation, target and actual total cash compensation and target and actual total compensation used for compensation analysis. This software can be run on most personal computers with Windows 10 or higher.

- **Microsoft Access** is a database management system (DBMS) from Microsoft that combines the relational Access Database Engine (ACE) with a graphical user interface and software-development tools. It is a member of the Microsoft 365 suite of applications that stores data in its own format or can import or link directly to data stored in other applications and databases. It was used to pull compensation and job data from AEP's payroll system for compensation analysis. This software can be run on most personal computers with Windows 10 or higher.

- **Power BI** cloud service with P1 Premium capacity, Data Gateways using Microsoft Windows Server 2019 VMs, Power BI Report Server using Windows Server 2019 VMs with SQL Server 2019. Power BI cloud service with P1 Premium capacity was used for data visualization, business intelligence, and analytics at a larger scale. The P1 Premium capacity enabled higher data refresh rates, larger data volume handling, and allowed for more users to access reports and dashboards simultaneously. Three Windows Server 2019 VMs were used to

run a Power BI Report Server Cluster for managing, distributing, and delivering reports within our organization, with one of those used to run SQL Server 2019 which stored report metadata/definitions, execution logs, subscriptions/schedules, and security permissions for the Power BI Report Server Cluster. Power BI Premium P1 capacity requires a dedicated cloud compute and storage resource in Microsoft's data centers. The P1 capacity offers 8 virtual cores, with 25GB of RAM. The Power BI data gateways require a machine running Windows Server 2019 VM, with four cores and 16 GB of RAM. The Power BI Report Server and SQL Server 2019 instances each run on a Windows Server 2019 VM. The hardware requirements for these VMs is 16 GB of RAM, and 100 GB of hard disk space. As a cloud service, Power BI can be accessed via a web browser or through the Power BI mobile app on various platforms (iOS, Android).

- **Peoplesoft HRMS 9.1 (Oracle)** is used for managing human resource functions, including employee data, benefits, payroll, and recruitment. It helps organizations streamline HR processes by automating tasks and providing centralized data management. Hardware requirements are a workstation with at least 4 GB of RAM, an Intel Core i3 or equivalent processor, and a display resolution of 1024x768 or higher. Web servers should be on multi-processor, multi-core machines with at least 4 GB of memory and 1 GB of disk space. Additional hardware requirements, like a 64-bit processor and OS, may also be needed for certain setups. The workstation hardware requirements include RAM: 4 GB minimum for 64-bit computers, 256 MB recommended, Processor: Intel Core i3 or equivalent, Display: 1024x768 resolution or higher, High Color (16-bit) mode recommended, Graphics Controller: VGA controller, and a 64-bit processor and OS may be required for some installations. This software was used for Payroll and Human Resources data prior to October 2023.

- **Workday HCM (Workday HR)**, also known as Human Capital Management (HCM), is a cloud-based HR software solution designed to help businesses manage their workforce more effectively. It offers a comprehensive suite of tools for managing various HR processes, including payroll, time tracking, talent management, and employee experience. Workday HCM aims to streamline these processes, making them more efficient and effective for both HR teams and employees. Multi-processor and multi-core machines are recommended for web servers, 4 GB or higher per web server, and 1 GB recommended for web server software. This software was used for Payroll and Human Resources data after October 2023.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(p)
Sponsoring Witness: Franz D. Messner

Filing Requirement:

Prospectuses of the most recent stock or bond offerings;

Response:

The most recent available prospectuses are included as Exhibit P to Section II of the Application. Kentucky Power has not included the prospectuses for the June 2025 securitization bond placement as those bonds were issued by Kentucky Power Cost Recovery LLC, which is a separate legal entity.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(q)
Sponsoring Witness: Jeffrey D. Newcomb

Filing Requirement:

Annual report to shareholders, or members, and statistical supplements covering the two (2) most recent years from the utility's application filing date;

Response:

Kentucky Power's annual reports for the years ended December 2023 and December 2024 are included as Exhibit Q to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(r)
Sponsoring Witness: Jeffrey D. Newcomb

Filing Requirement:

The monthly managerial reports providing financial results of operations for the twelve (12) months in the test period;

Response:

The Company's monthly financial reports for the months of June 2024 through May 2025 are included as Exhibit R to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(s)
Sponsoring Witness: Jeffrey D. Newcomb

Filing Requirement:

A copy of the utility's annual report on Form 10-K as filed with the Securities and Exchange Commission for the most recent two (2) years, any Form 8-K issued during the past two (2) years, and any Form 10-Q issued during the past six (6) quarters updated as current information becomes available;

Response:

Kentucky Power Company is no longer a registrant with the Securities and Exchange Commission and has not filed Forms 10-K or 10-Q since 2007. Kentucky Power did, however, file two 8-Ks with the Securities and Exchange Commission in connection with securitization in 2025, which are included in Exhibit S to Section II of the Application.

The following Company quarterly reports are also included as Exhibit S to Section II of the Application:

Kentucky Power Company 2023 Q2 Quarterly
Kentucky Power Company 2023 Q3 Quarterly
Kentucky Power Company 2024 Q1 Quarterly
Kentucky Power Company 2024 Q2 Quarterly
Kentucky Power Company 2024 Q3 Quarterly
Kentucky Power Company 2025 Q1 Quarterly
Kentucky Power Company 2025 Q2 Quarterly

Kentucky Power's annual reports for the years ended December 2023 and 2024 are included as Exhibit Q to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(t)
Sponsoring Witness: Brian C. Ciborek & Tanner S. Wolffram

Filing Requirement:

If the utility had amounts charged or allocated to it by an affiliate or general or home office or paid monies to an affiliate or general or home office during the test period or during the previous three (3) calendar years, the utility shall file:

1. *A detailed description of the method and amounts allocated or charged to the utility by the affiliate or general or home office for each charge allocation or payment;*

2. *An explanation of how the allocator for the test period was determined; and*

3. *All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated, or paid during the test period was reasonable.*

Response:

The amounts charged or allocated by an affiliate are included in Exhibit T to Section II of the Application. Amounts are allocated or charged in accordance with the Company's cost allocation manual developed and maintained in accordance with KRS 278.2203 and KRS 278.2205. A copy of the Company's cost allocation manual is included as Exhibit A to Section II of the Application.

The Company owns an undivided 50% interest in the Mitchell Plant. Through August 2022, the Company was also the operator of the Mitchell Plant. In September 2022, Wheeling Power Company ("Wheeling Power"), an affiliated AEP subsidiary company and owner of the remaining 50% undivided interest in the Mitchell Plant, became operator of the Mitchell Plant, pursuant to the September 1, 2022 Written Consent Action of the Mitchell Operating Committee. The plant operator initially records 100% of all Mitchell Plant costs. Then, the plant operator bills the other joint owner of the plant its share of Mitchell Plant costs (including AEP Service Corporation charges), in accordance with the FERC-approved Mitchell Operating Agreement, including the September 1, 2022 Written Consent Action of the Mitchell Operating Committee. The Mitchell Plant Operating Agreement and the September 1, 2022 Written Consent Action are included as Exhibit U to Section II of the Company's Application. The Company currently has a pending application, Case No. 2025-00175, to extend its 50% interest in the energy and

capacity from Mitchell beyond 2028. This is discussed in the testimony of Company Witness Wolffram.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(u)
Sponsoring Witnesses: Jaclyn N. Cost & Nicole M. Coon

Filing Requirement:

If the utility provides gas, electric, water, or sewage utility service and has annual gross revenues greater than $5,000,000 a cost of service study based on a methodology generally accepted within the industry and based on current and reliable data from a single time period; and

Response:

The cost-of-service studies based on current and reliable data for the test year ended May 31, 2025, are included in the testimony of Company Witnesses Cost and Coon. The jurisdictional cost-of-service is included in Section V, Schedules 4 and 5 to the Company's application. The class cost-of-service is included in Exhibit NMC-1 of Company Witness Coon's Direct Testimony.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(4)(v)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Local exchange carriers with more than 50,000 access lines shall file:

1. *A jurisdictional separations study consistent with 47 C.F.R. Part 36; and*

2. *Service specific cost studies to support the pricing of all services that generate annual revenue greater than $1,000,000 except local exchange access:*

   a. *Based on current and reliable data from a single time period; and*

   b. *Using generally recognized fully allocated, embedded, or incremental cost principles.*

Response:

Not Applicable.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(5)(a)
Sponsoring Witness: Brian C. Ciborek

Filing Requirement:

Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just, and reasonable rates based on the historical test period. The following information shall be filed with each application requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:

> *(a) A detailed income statement and balance sheet reflecting the impact of all proposed adjustments;*

Response:

The required information is included on Pages 3, 4, and 7 of Section IV of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(5)(b)
Sponsoring Witness: Jeffrey D. Newcomb

Filing Requirement:

The most recent capital construction budget containing at least the period of time as proposed for any pro forma adjustment for plant additions;

Response:

The most recent capital construction budget is included in Application Section II, Exhibit V.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(5)(c)
Sponsoring Witness: Michele Ross

Filing Requirement:

For each proposed pro forma adjustment reflecting plant additions, provide the following information:

1. *The starting date of the construction of each major component of plant;*

2. *The proposed in-service date;*

3. *The total estimated cost of construction at completion;*

4. *The amount contained in construction work in progress at the end of the test period;*

5. *A schedule containing a complete description of actual plant retirements and anticipated plant retirements related to the pro forma plant additions including the actual or anticipated date of retirement;*

6. *The original cost and the cost of removal and salvage for each component of plant to be retired during the period of the proposed pro forma adjustment for plant additions;*

7. *An explanation of differences, if applicable, in the amounts contained in the capital construction budget and the amounts of capital construction cost contained in the pro forma adjustment period; and*

8. *The impact on depreciation expense of all proposed pro forma adjustments for plant additions and retirements;*

Response:

The only proposed pro forma adjustment responsive to this requirement is the proposed capital adjustment associated with the TOR Program detailed and supported in the Direct Testimony of Company Witness Michele Ross.

1. The anticipated start date for the trees outside the right-of-way ("TOR") Program projects described in Company Witness Ross's Direct Testimony is presented in column 'K' of the 'TOR Work Plan' tab of Company Witness Ross's Exhibit MR-4.

2. Individual projects are anticipated to be completed in the same year in which execution begins. Please see the Company's response to subpart (1) above. For the in-service date for each Project ID, please see column 'E' on the ' Project Detail' tab of Exhibit MR-4.

3. Each year TOR Program projects are accounted via a single Project ID and work order. For the estimated cost of completion for each year's corresponding work order, please see the 'Capital Funding for TOR Reliability Widening per Year' Table on the 'Tables' tab of Exhibit MR-4.

4. For the amount of CWIP for each project at the end of the test year, see column 'F' on the 'Project Detail' tab of Exhibit MR-4. For a breakdown of charges made to the active Project ID, TREEREL25, please see the 'TREEREL25 Charges in CWIP tab' of the same exhibit.

5. Not applicable.

6. Not applicable.

7. The variance between the project costs in Exhibit MR-4 and the proposed proforma adjustment are due the timeframes analyzed for each. The proforma highlights dollars to be spent in the 12 months after the test year, while the estimated Project ID costs in Exhibit MR-4 represent expected charges to the project in the stated calendar year.

8. The Company has calculated depreciation both at the current rate of 3.52% and the proposed rate of 3.25%. The depreciation rate is added to the conductor property amounts in FERC account 365. See columns 'J' and 'K' on the 'Project Detail' tab of Exhibit MR-4. Depreciation rates are charged per Project ID, not per circuit.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(5)(d)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

The operating budget for each month of the period encompassing the pro forma adjustments; and

Response:

Kentucky Power's operating budget for each month through December 2025 is included in Exhibit W to Section II of the Application.

The operating budget for each month January 2026 through May 2026 is not yet available. The Company will supplement the record with this information once available.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(5)(e)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

The number of customers to be added to the test period end level of customers and the related revenue requirements impact for all pro forma adjustments with complete details and supporting work papers.

Response:

The requested information does not exist. Kentucky Power's overall customer count is declining and there are no customers to be added to the test period end level of customers. Please see the Direct Testimony of Jeffrey D. Newcomb for additional detail. Nor is there any related revenue requirement impact to any pro forma adjustments resulting from adding customers to the test period end level of customers. Please see Application, Section II, Exhibit I, p. 2 ("Customer Annualization Revenue" Column).

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(6) – 16(8)(n)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Filing Requirements 807 KAR 5:001 Section 16(6) to 807 KAR 5:001 Section 16(8)(n)

Response:

Not Applicable.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(9)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

The commission shall notify the applicant of any deficiencies in the application within thirty (30) days of the application's submission. An application shall not be accepted for filing until the utility has cured all noted deficiencies;

Response:

Kentucky Power will comply with the requirements established in 807 KAR 5:001 Section 16(9).

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 16(10)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

A request for a waiver from the requirements of this section shall include the specific reasons for the request. The commission shall grant the request upon good cause shown by the utility. In determining if good cause has been shown, the commission shall consider:

(a) If other information that the utility would provide if the waiver is granted is sufficient to allow the commission to effectively and efficiently review the rate application;

(b) If the information that is the subject of the waiver request is normally maintained by the utility or reasonably available to it from the information that it maintains;

(c) The expense to the utility in providing the information that is the subject of the waiver request.

Response:

The Company is not requesting any waivers from the requirements in this section.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 17(1)(a)
807 KAR 5:011 Section 8(1)(a)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Public postings.

(a) A utility shall post at its place of business a copy of the notice no later than the date the application is submitted to the commission.

Response:

Kentucky Power has complied with 807 KAR 5:001, Section 17(1)(a) and 807 KAR 5:011 Section 8(1)(a) by posting its notice ("Customer Notice") on or before the day that the Application is filed with the Public Service Commission at the locations shown below.

- 1645 Winchester Avenue, Ashland, Kentucky 41101
- 12333 Kevin Avenue, Ashland, Kentucky 41102
- 1400 E. Main Street, Hazard, Kentucky 41701
- 3249 North Mayo Trail, Pikeville, Kentucky 41501

The Customer Notice will remain posted until the Commission enters a final decision in this matter.

A copy of the Customer Notice is included in Exhibit F to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 17(1)(b)
807 KAR 5:011 Section 8(1)(b)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Public postings.

(b) A utility that maintains a Web site shall, within five (5) business days of the date the application is submitted to the commission, post on its Web sites:

1. A copy of the public notice; and

2. A hyperlink to the location on the commission's Web site where the case documents are available.

Response:

Kentucky Power will within five (5) business days of filing its Application post on its website a copy of the public notice along with a hyperlink to the filing on the Commission's website. The Customer Notice will remain posted until the Commission enters a final decision in this matter.

A copy of the Customer Notice is included in Exhibit F to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 17(1)(c)
807 KAR 5:011 Section 8(1)(c)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Public postings.

> *(c) The information required in paragraphs (a) and (b) of this subsection shall not be removed until the commission issues a final decision on the application.*

Response:

Kentucky Power will comply with the requirements established in 807 KAR 5:001 Section 17(1)(c) and 807 KAR 5:011 Section 8(1)(c).

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 17(2)(b)
807 KAR 5:011 Section 8(2)(b)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Customer Notice.

(b) If a utility has more than twenty (20) customers, it shall provide notice by:

1. Including notice with customer bills mailed no later than the date the application is submitted to the commission;

2. Mailing a written notice to each customer no later than the date the application is submitted to the commission;

3. Publishing notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area, the first publication to be made no later than the date the application is submitted to the commission; or

4. Publishing notice in a trade publication or newsletter delivered to all customers no later than the date the application is submitted to the commission.

(c) A utility that provides service in more than one (1) county may use a combination of the notice methods listed in paragraph (b) of this subsection.

Response:

Kentucky Power is complying with 807 KAR 5:001 Section 17(2)(b)(3) and 807 KAR 5:011 Section 8(2)(b)(3) by publishing in newspapers of general circulation in its service territory a copy of the Customer Notice for publication once a week for three (3) consecutive weeks in a prominent manner. The Customer Notice was first published beginning August 22, 2025.

A copy of the Customer Notice and listing of newspapers that will run the Customer Notice are included in Exhibit F to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 17(3)
807 KAR 5:011 Section 8(3)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Proof of Notice. A utility shall file with the commission no later than forty-five (45) days from the date the application was initially submitted to the commission:

(a) If notice is mailed to its customers, an affidavit from an authorized representative of the utility verifying the contents of the notice, that notice was mailed to all customers, and the date of the mailing;

(b) If notice is published in a newspaper of general circulation in the utility's service area, an affidavit from the publisher verifying the contents of the notice, that the notice was published, and the dates of the notice's publication; or

(c) If notice is published in a trade publication or newsletter delivered to all customers, an affidavit from an authorized representative of the utility verifying the contents of the notice, the mailing of the trade publication or newsletter, that notice was included in the publication or newsletter, and the date of mailing.

Response:

Kentucky Power will provide the prescribed affidavits within forty-five (45) days of the date the Company files its Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 17(4)(a)
807 KAR 5:011 Section 8(4)(a)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> *(a) The proposed effective date and the date the proposed rates are expected to be filed with the commission;*

Response:

The Customer Notice complies with this requirement. A copy of the Customer Notice is included in Exhibit F to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 17(4)(b)
807 KAR 5:011 Section 8(4)(b)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> *(b) The present rates and proposed rates for each customer classification to which the proposed rates will apply;*

Response:

The Customer Notice complies with this requirement. A copy of the Customer Notice is included in Exhibit F to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 17(4)(c)
807 KAR 5:011 Section 8(4)(c)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> *(c) The amount of the change requested in both dollar amounts and percentage change for each customer classification to which the proposed rates will apply;*

Response:

The Customer Notice complies with this requirement. A copy of the Customer Notice is included in Exhibit F to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 17(4)(d)
807 KAR 5:011 Section 8(4)(d)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> *(d) The amount of the average usage and the effect upon the average bill for each customer classification to which the proposed rates will apply, except for local exchange companies, which shall include the effect upon the average bill for each customer classification for the proposed rate change in basic local service;*

Response:

The Customer Notice complies with this requirement. A copy of the Customer Notice is included in Exhibit F to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 17(4)(e)
807 KAR 5:011 Section 8(4)(e)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> *(e) A statement that a person may examine this application at the offices of (utility name) located at (utility address);*

Response:

The Customer Notice complies with this requirement. A copy of the Customer Notice is included in Exhibit F to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 17(4)(f) and (g)
807 KAR 5:011 Section 8(4)(f) and (g)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> *(f) A statement that a person may examine this application at the commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or through the commission's Web site at http://psc.ky.gov;*
>
> *(g) A statement that comments regarding the application may be submitted to the Public Service Commission through its Web site or by mail to Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602;*

Response:

The Customer Notice complies with these requirements. A copy of the Customer Notice is included in Exhibit F to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 17(4)(h)
807 KAR 5:011 Section 8(4)(h)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> *(h) A statement that the rates contained in this notice are the rates proposed by (utility name) but that the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice;*

Response:

The Customer Notice complies with these requirements. A copy of the Customer Notice is included in Exhibit F to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:001 Section 17(4)(i) and (j)
807 KAR 5:011 Section 8(4)(i) and (j)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> *(i) A statement that a person may submit a timely written request for intervention to the Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party; and*
>
> *(j) A statement that if the commission does not receive a written request for intervention within thirty (30) days of initial publication or mailing of the notice, the commission may take final action on the application.*

Response:

The Customer Notice complies with these requirements. A copy of the Customer Notice is included in Exhibit F to Section II of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:011 Section 8(5)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Compliance by electric utilities with rate schedule information required by 807 KAR 5:051. Notice given pursuant to subsection (2)(a) or (b) of this section shall substitute for the notice required by 807 KAR 5:051, Section 2, if the notice contained a clear and concise explanation of the proposed change in the rate schedule applicable to each customer.

Response:

807 KAR 5:051 has been repealed. Notwithstanding, the Company complied with the requirements established in 807 KAR 5:011 Section 8(5).

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:011 Section 8(6)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Periodic recalculation of a formulaic rate that does not involve a revision of the rate and that is performed in accordance with provisions of an effective rate schedule, special contract, or administrative regulation does not require notice in accordance with this section.

Response:

Not Applicable.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:011 Section 9(1)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

The proposed rates on a new tariff or revised sheet of an existing tariff shall become effective on the date stated on the tariff sheet if:

(a) Proper notice was provided to the public in accordance with Section 8 of this administrative regulation;

(b) Statutory notice was provided; and

(c) The commission does not suspend the proposed rates pursuant to KRS 278.190.

Response:

The Company complied with the requirements established in 807 KAR 5:011 Section 9(1). The Statutory Notice is included as Exhibit 1 to Section I of the Application.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
807 KAR 5:011 Section 9(2)
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

All information and notices required by this administrative regulation shall be furnished to the commission at the time of the filing of the proposed rate. If a substantial omission occurs, which is prejudicial to full consideration by the commission or to the public, the statutory notice period to the commission shall not commence until the omitted information and notice is filed.

Response:

Kentucky Power has complied with the requirements established in 807 KAR 5:011 Section 9(2).

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
Case 2021-00428 Order on Smart Grid Technologies
Sponsoring Witness: Michele Ross

Filing Requirement:

The Commission's April 13, 2016, order in Case 2012-00428 requires each jurisdictional utility to identify Smart Grid investments in each rate case.

Response:

Kentucky Power's Smart Grid investments are identified in the Direct Testimony of Michele Ross.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
Admin Case 327 Order on Economic Development Reporting
Sponsoring Witness: Michael M. Spaeth

Filing Requirement:

Finding No. 8 of the Commission's September 24, 1990 Order in Administrative Case No. 327 requires Kentucky Power to demonstrate in rate proceedings a detailed cost-of-service analysis that nonparticipating customers are not adversely affected by EDR customers.

Response:

The required demonstration is included with the Direct Testimony of Michael M. Spaeth.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
Case No. 2020-00019 on Air Products Special Contract
Sponsoring Witness: Michael M. Spaeth

Filing Requirement:

Finding No. 3 of the Commission's April 23, 2020 Order in Case No. 2020-00019 requires Kentucky Power to demonstrate in rate proceedings a detailed cost-of-service analysis that ratepayers are not adversely affected by the Special Contract rate to Air Products.

Response:

The required demonstration is included with the Direct Testimony of Company Witness Michael M. Spaeth.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
Case No. 2024-00344 on AMI
Sponsoring Witness: Michele Ross

Filing Requirement:

Kentucky Power shall develop and file with its next base rate application, and continue in rate base applications until such time a base rate application requests to address the regulatory asset related to AMI installation is addressed, detailed plans on AMI obsolescence and replacement strategies that identify, at a minimum, risks and solutions to early obsolescence, opportunities for greater cross-system compatibility, and successor technologies, including hardware and software, in order to extend the life of as many portions of the proposed AMI systems as reasonably practical.

Response:

The required information is included in the Direct Testimony of Michele Ross.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
Case No. 2024-00344 on AMI
Sponsoring Witness: Michele Ross

Filing Requirement:

Kentucky Power shall develop and file with its next base rate application, and continue in rate base applications until such time a base rate application requests to address the regulatory asset related to AMI installation is addressed, detailed plans regarding how Kentucky Power identifies outages, how the AMI systems will facilitate notification and communication of information with customers regarding outages, the estimated times of repair.

Response:

The required information is included in the Direct Testimony of Michele Ross.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
Case No. 2024-00344 on AMI
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Kentucky Power shall develop and file with its next base rate application a detailed plan for reducing the frequency and amounts of its tariffed nonrecurring charges resulting from it proposed AMI systems.

Response:

The required information is included in the Direct Testimony of Tanner S. Wolffram.

Kentucky Power Company
KPSC Case No. 2025-00257
Minimum Standard Filing Requirements
Test Year 12 Months Ending May 31, 2025

Filing Requirement
Case No. 2024-00344 on AMI
Sponsoring Witness: Tanner S. Wolffram

Filing Requirement:

Kentucky Power may seek AMI cost recovery in the first base rate case proceedings following AMI implementation if necessary; otherwise, if no base rate adjustment is required, Kentucky Power shall make a separate filing to address the AMI revenue requirement impact and set the amortization periods for associated regulatory assets following AMI implementation.

Response:

The Company is not seeking AMI cost recovery with this Application, as AMI has not yet been deployed.

COST ALLOCATION MANUAL

As Of December 31, 2024

Corporate Accounting

The manual has been written to document AEP's approach to cost allocation and transfer pricing of affiliate transactions. Its purposes are to

- provide an easily referenced source of information
- state and clarify policy
- formalize procedures
- provide a basis of communication between all employees concerning cost allocation matters
- meet all regulatory requirements for maintaining a cost allocation manual.

The contents of the manual have been approved by management. Responsibility for adhering to the policies and procedures rests with every employee.

The manual is maintained in the A-Z index of AEP Now, under 'Cost Allocation Manual'. Maintenance of the documents incorporated in the manual by reference is the responsibility of the individuals and groups designated in the manual.

Errors in content and other requests for revision of this manual should be directed to the attention of Brian T. Lysiak.

Brian T. Lysiak
Senior Manager – Corporate Accounting

Jeffrey W. Hoersdig
Assistant Controller – Corporate Accounting

AEP AMERICAN ELECTRIC POWER

CAM
Amendment Record

Rev. No.	Date Issued	Rev. No.	Date Issued	Rev. No.	Date Issued	Rev. No.	Date Issued
1	01-02-01	26	03-15-13	51		76	
2	10-22-01	27	08-31-13	52		77	
3	05-10-02	28	03-27-14	53		78	
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HOW TO USE THIS MANUAL

SUMMARY

This Manual is divided into

TABS - major divisions within the manual

SECTIONS - divisions within a TAB

SUBJECTS - divisions within a SECTION.

DOCUMENT NUMBERING SYSTEM

Each document (i.e., subject) has a unique 6-digit number. This number is divided into 3 sets of two digits which are separated by dashes.

EXAMPLE: **05 – 03 – 02**
TAB-SECTION-SUBJECT

INDEXES

The alphabetic subject index is the key to this manual. It appears in the "Controls" TAB following this document.

Alphabetic Subject

The alphabetic subject index (00-00-03) lists every subject in this manual in alphabetical order along with the document number at which each subject may be located. To be able to retrieve information, each subject (and important captions within a subject) are listed three or more ways in the index.

Locating a Document

Document numbers appear in bold print on the upper right corner of each page (see top of this page). To locate a Subject:

1. Refer to the Alphabetic Subject Index and locate the SUBJECT you need.

2. Note the Document Number indicated

EXAMPLE: **05-03-02**

Locating a Document (Cont'd)

3. Locate TAB 5 of the manual and within this TAB find SECTION 03 and SUBJECT 02. Or, if you are viewing this manual electronically using Acrobat Reader, simply click on the subject line listed in the table of contents.

TABLE OF CONTENTS

The table of contents (00-00-01) is intended to give a cover-to-cover overview of the manual contents and organization. It lists contents of a TAB to the SUBJECT level in document number order. (Subjects are listed alphabetically in the Alphabetic Subject Index).

FORMAT

The format followed for each TAB within this manual may vary. Uniformity of format has been attempted to the extent practicable.

DISTRIBUTION

The AEPSC Corporate Accounting Department is solely responsible for the issuance, revision and distribution of all copies of this manual and database.

Revisions or additions to the manual will be issued as required. If practical, such revisions and/or additions will be accumulated and issued periodically as a group. The date of the latest revision or addition will appear at the bottom of the page in the left-hand corner.

AMENDMENTS

All users of this manual are urged to contribute ideas and suggestions for

revisions to this manual.

Amendment Record

An amendment record is kept of all revisions to this manual. The amendment record appears in the front of this manual as the first document in the "Controls" SECTION.

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OVERVIEW (GENERAL)

SUMMARY	American Electric Power Company, Inc. (AEP) is a public utility holding company. It has subsidiaries that conduct regulated operations and non-regulated operations.
BUSINESS	AEP is one of the United States' largest generators of electricity and owns the nation's largest electricity transmission system. AEP delivers electricity to customers in eleven states: Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. Wholly-owned subsidiaries are involved in power engineering and construction services and energy management.
ORGANIZATION CHART	The ownership relationship between AEP, its subsidiaries, and their subsidiaries at successive levels is captured in AEP's corporate chart.
AFFILIATE TRANSACTIONS	AEP, its subsidiaries and certain other affiliates in the AEP holding company system conduct capital (i.e., financial) transactions among themselves. The subsidiaries, in certain situations, also perform services for one another.

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Organization Chart

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OVERVIEW

SUMMARY	American Electric Power Company, Inc. (AEP) is a public utility holding company. It has direct subsidiaries (first tier) and indirect subsidiaries (second tier and lower).
CORPORATE CHART	A listing of the direct and indirect subsidiaries of AEP, including domestic and foreign subsidiaries, is contained in AEP's corporate organization chart.

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CORPORATE CHART

SUMMARY

American Electric Power Company, Inc. (AEP) is a public utility holding company. It has no customers or employees nor does it own any utility property. AEP does own common stock of ten operating electric utility companies.
AEP also owns common stock of American Electric Power Service Corporation (AEPSC) and other domestic and foreign subsidiaries.

AEPSC is a management, professional and technical services organization that provides such services, at cost, to AEP, the operating electric utility companies in the AEP System, and other affiliated companies. Other AEP subsidiaries provide power engineering, energy consulting and energy management services.

CORPORATE ORGANIZATION CHART

The following organization chart lists hierarchically all of the direct and indirect subsidiaries of AEP. Company names are indented to identify them as subsidiaries of the company that is listed immediately above them at the next tier. Some companies are subsidiaries of more than one company. The footnotes provide a general description of the business conducted by each company.

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02. Snowcap Coal Company, Inc.	[Note L]
01. AEP Credit, Inc.	[Note R],[VIE]
01. AEP Development Services, LLC	[Note F],[VIE]
01. AEP Energy Supply LLC	[Note I]
02. AEP Clean Energy Resources, LLC.	[Note X]
02. AEP Energy Partners, Inc.	[Note W]
02. AEP Energy Services LLC	[Note W]
02. AEP Generation Resources Inc.	[Note E]
03. Conesville Coal Preparation Company	[Note M]
03. Ohio Franklin Realty, LLC	[Note T]
04. Central Coal Company (Inactive)	(Inactive),[Note K]
02. AEP Retail Energy Partners LLC	[Note I]
03. AEP Energy, Inc.	[Note I]
04. Blue Star Energy, LLC	[Note I]
02. Kamaaha PNL, LLC	[Note I]
02. Kona CE, LLC	[Note I]
02. CSW Energy, Inc.	[Note I]
03. AEP Properties, LLC	[Note X]
01. AEP Generating Company	[Note E],[VIE]
01. AEP Investments, Inc.	[Note F]
02. Adelphi Bank	[Note I]
02. AEP Cyber Risk, LLC	[Note I]
03. Fortress Security Holdings LLC	[Note I]
02. AEP Investments Holding Company, Inc.	[Note D]
03. AEP Energy Services Gas Holding Company	[Note D]
02. AEP Ventures, LLC	[Note GG]
02. Allumia, Inc	[Note DD]
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02. Datamaran Limited	[Note DD]
02. Energize Ventures Fund II LP	[Note DD]
02. Energize Ventures Fund III LP	[Note DD]
02. Main Spring Energy, Inc.	[Note DD]
02. Powerhouse Ventures Fund II LP	[Note DD]
02. Sensewaves	[Note DD]
02. Urbint Inc.	[Note DD]
02. Utilidata, Inc.	[Note DD]
02. Westly Capital Partners Fund III, L.P.	[Note DD]
02. Westly Capital Partners Fund IV, L.P.	[Note DD]
02. Westly Seed Fund, L.P.	[Note DD]
01. AEP Nonutility Funding LLC	[Note AA],[VIE]
01. AEP Pro Serv, Inc.	[Note I]
02. United Sciences Testing, Inc.	[Note B]
01. AEP T&D Services, LLC	[Note BB]
01. AEP Texas, Inc	[Note J]
02. AEP Texas Central Transition Funding III LLC	[Note AA],[VIE]
02. AEP Texas North Generation Company, LLC	[Note E]
02. AEP Texas Restoration Funding, LLC	[Note AA],[VIE]
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02. AEP Storage Holding Company, LLC	[Note P]
03. AEP Storage New York, LLC	[Note P]
02. AEP Transmission Company, LLC	[Note P]
03. AEP Appalachian Transmission Company, Inc.	[Note P]
03. AEP Indiana Michigan Transmission Company Inc.	[Note P]
03. AEP Kentucky Transmission Company, Inc.	[Note P]
03. Midwest Transmission Holdings, LLC	[Note P]
03. AEP Ohio Transmission Company Inc.	[Note P]
03. AEP Oklahoma Transmission Company, Inc.	[Note P]
03. AEP Southwestern Transmission Company, Inc.	[Note P]
03. AEP West Virginia Transmission Company, Inc.	[Note P]
02. Bold Transmission LLC	[Note P]

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02. RITELine Transmission Development, LLC	[Note P],[VIE]
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03. Transource Midcontinent, LLC	[Note P]
03. Transource Missouri, LLC	[Note P]
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04. Transource New York Development Company, Inc.	[Note T]
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03. Valley Link Transmission Virginia, LLC	[Note P]
03. Valley Link Transmission Virginia Development, Inc.	[Note T]
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01. AEP Utility Funding, LLC	[Note AA],[VIE]
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02. American Electric Power Foundation	[Note FF]
01. Appalachian Power Company	[Note J]
02. Amherst County VA S1, LLC	[Note J]
02. Appalachian Consumer Rate Relief Funding LLC	[Note AA],[VIE]
02. Cedar Coal Co. (Inactive)	(Inactive),[Note K]
02. Central Appalachian Coal Company (Inactive)	(Inactive),[Note K]
02. Central Coal Company (Inactive)	(Inactive),[Note K]
02. Southern Appalachian Coal Company (Inactive)	(Inactive),[Note K]
01. Franklin Real Estate Company	[Note T]
02. Indiana Franklin Realty, Inc.	[Note T]
01. Indiana Michigan Power Company	[Note J]
02. Price River Coal Company, Inc. (Inactive)	(Inactive),[Note K]
01. Kentucky Power Company	[Note J]
02. Kentucky Power Cost Recovery LLC	[Note AA],[VIE]
01. Kingsport Power Company	[Note J]
01. Kyte Works, LLC	[Note I]
01. Ohio Power Company	[Note J]
02. NCT Ventures Fund II	[Note AA]
02. Ohio Valley Electric Corporation	[Note E],[VIE]
03. Indiana-Kentucky Electric Corporation	[Note E]
02. Rev1 Ventures Fund I	[Note DD]
02. Rev1 Ventures Fund II	[Note DD]
01. Ohio Valley Electric Corporation	[Note E],[VIE]

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Organization Chart

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CORPORATE CHART

02. Indiana-Kentucky Electric Corporation	[Note E]
01. Oil Casualty Insurance, Ltd.	[Note I]
01. Public Service Company of Oklahoma	[Note J]
02. Rock Falls Wind Farm, LLC	[Note J]
01. Southwestern Electric Power Company	[Note J]
02. Diversion Wind Energy, LLC	[Note J]
02. Dolet Hills Lignite Company, LLC	[Note L],[VIE]
02. Mutual Energy SWEPCo, LLC	[Note W]
02. Oxbow Lignite Company, LLC	[Note L]
02. Southwest Arkansas Utilities Corporation	[Note T]
02. SWEPCo Storm Recovery Funding LLC	[Note AA],[VIE]
01. Wheeling Power Company	[Note J]

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Organization Chart

Subject

CORPORATE CHART

Variable Interest Entity (VIE) in accordance with generally accepted accounting principles, no costs are allocated to this entity.

Notes:
A. Public utility holding company.
B. Management, professional and technical services.
C. Telecommunications.
D. Broker and market energy commodities.
E. Generation.
F. Investor in companies developing energy-related ideas, products and technologies.
G. Distributed generation products.
H. International energy-related investments, trading and other projects.
I. Non-regulated energy-related services and products.
J. Domestic electric utility.
K. Coal mining (inactive).
L. Coal mining (active).
M. Coal preparation.
N. Inactive.
O. Subsidiary public utility holding company.
P. Electric transmission.
Q. Leasing.
R. Accounts receivable factoring.
S. Independent power.
T. Real estate.
U. Staff augmentation to power plants.
V. Retail energy sales.
W. Marketing of natural gas, electricity or energy-related products.
X. Wind Power Generation.
Y. Barging Services
AA. Finance Subsidiary
BB. Energy services including operations, supply chain, transmission and distribution

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Organization Chart

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CORPORATE CHART

CC. Gas pipeline and processing
DD. Domestic energy-related investments, trading and other projects
EE. Trust
FF. Nonprofit
GG. Broadband Services.

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Cost Allocation Manual

Section

Affiliate Transactions

Subject

OVERVIEW

SUMMARY	The electric utilities in the AEP holding company system conduct transactions with each other, American Electric Power Service Corporation (AEPSC) and their non-regulated affiliates.
AEPSC Services Rendered	AEPSC provides management, technical and professional services to other companies within the AEP holding company system. **01-03-02**
INTERCOMPANY PRODUCTS AND SERVICES	The electric utility companies provide products and services to each other and in certain cases they provide products and services to non-regulated affiliates and receive products and services from non-regulated affiliates. **01-03-03**
MONEY POOL	The operation of the AEP Utility and Non-utility Money Pool is designed to match, on a daily basis, the available cash and borrowing requirements of its participants, thus minimizing the need to borrow from external sources. **01-03-04**
RESEARCH AND DEVELOPMENT	Research and development (R&D) activities are generally performed by AEP System companies on a shared basis. AEPSC manages most R&D projects. **01-03-05**

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Cost Allocation Manual

Section

Affiliate Transactions

Subject

OVERVIEW

FINANCIAL TRANSACTIONS

The AEP System companies, although legally separated, operate on an integrated basis, as permitted by law and regulation. Financial transactions are conducted on a regular basis in support of the integrated activities.

01—03-06

INTELLECTUAL PROPERTY

Revenues derived from non-associates for the resale and licensing of property protected by copyright, patent or trademark laws are shared among AEP affiliates and regulated by the Federal Regulatory Commission (FERC) under the Public Utility Holding Company Act of 2005.

01-03-07

CONVENIENCE PAYMENTS

Payments made for the convenience of another associate company within the AEP System need to be kept to a minimum and be reimbursed immediately to the paying company.

01-03-08

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Cost Allocation Manual

Section

Affiliate Transactions

Subject

SERVICES RENDERED BY AEPSC

SUMMARY

The services provided by AEPSC are regulated by the Federal Energy Regulatory Commission (FERC) under the Public Utility Holding Company Act of 2005.

SUMMARY OF AEPSC SERVICES

The following table provides a listing of services AEPSC provides to affiliate companies:

GROUP/FUNCTION	DESCRIPTION
Audit Services	Audit Services provides audit and review services to assist management and the Board of Directors in the effective discharge of their responsibilities to establish, maintain, and oversee a proper internal control environment.
Chief Administrative Officer Administration	Executive management support of all areas of the Chief Administrative Officer.
Chief Executive Officer Administration	Services provided by the office of the chairman.
Chief Security Officer Administration	The Chief Security Officer provides, among other items, overall direction and management to all companies in the AEP system, and includes the CEO and his staff.
Chief Financial Officer Administration	Executive management support of all areas of Finance, Accounting and

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Section

Affiliate Transactions

Subject

SERVICES RENDERED BY AEPSC

GROUP/FUNCTION	DESCRIPTION
	Strategic Planning as well as miscellaneous accounting billings and adjustments.
Commercial Operations	Capture maximum value for surplus generation and secure competitive, low-cost supplies from the market to meet the needs of the AEP System. Operational analyses, responsible for decision support modeling, dispatch pricing, and position reporting. Manage and administer non-affiliated gas marketing.
Corporate Accounting	Corporate Accounting & Finance provides services such as maintaining the books and records, preparing all monthly entries to the ledgers, and developing and maintaining the accounting and business systems that support the utilities. Services also include financial and regulatory reporting, managing financial resources, performing tax compliance and ensuring compliance with generally accepted

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Affiliate Transactions

Subject

SERVICES RENDERED BY AEPSC

GROUP/FUNCTION	DESCRIPTION
	accounting principles and corporate accounting policy.
Corporate Communications	Corporate Communications provides local corporate communications by distributing information to employees, the media, customers, civic leaders, and the public at large. Provide feedback to management from those various groups.
Corporate Human Resources	Human Resources responsible for interpreting, defining, writing, and administering the Company's human resource policies and providing human resource services to all AEP employees. Responsible for compliance with all related bodies of regulation, including EEO, ERISA, and OSHA.
Corporate Planning and Budgeting	Corporate Planning & Budgeting provides long and short range financial planning services, strategic planning and analysis, and budget services..

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Affiliate Transactions

Subject

SERVICES RENDERED BY AEPSC

GROUP/FUNCTION	DESCRIPTION
Customer and Distribution Services	Customer Services resolves customer problems and manages customer relationships. Primarily provide support in the areas of customer operations, billing support, website development, and customer solution centers. Distribution Services provides mapping services, contract administration, data analysis and benchmarking, system budgeting, line training, project management, design and development of construction projects, drafting and engineering services, and planning services.
Distribution, Customer Ops, and Regulatory Services Administration	Other includes, among other items, executive management support of all areas of the Distribution, Customer Operations, and Regulatory Services.
Energy Supply Administration	Services include administration of coordinating the dispatch of AEP's competitive generation fleet and engage in marketing, risk

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Affiliate Transactions

Subject

SERVICES RENDERED BY AEPSC

GROUP/FUNCTION	DESCRIPTION
	management and retail activities in ERCOT, PJM and MISO.
Environment and Safety	Support of environmental and safety concerns.
Federal Affairs	Monitors and participates in rulemakings and other public policy discussions at various federal agencies.
Fossil and Hydro Generation	Provide power plants with engineering and technical resources necessary to manage day-to-day operations issues affecting unit reliability, availability, and equipment performance.
Generation Administration	Services provided by the Generation Administration.
Generation Business Services	Business support services for operation and maintenance of AEP generating assets.
Generation Engineering and Technical Services – Engineering Services	Administration of all generation assets: fossil, hydro, and engineering technical services
Generation Engineering and Technical Services –	Administration of all generation assets: fossil, hydro, and

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Section

Affiliate Transactions

Subject

SERVICES RENDERED BY AEPSC

GROUP/FUNCTION	DESCRIPTION
Project and Contstruction	engineering technical & project and construction
Information Technology	Information processing, business unit support, application development, client computing and technical software support and EAS solutions and telecommunication operations.
Investor Relations	Investment services.
Legal	Legal counsel and public/regulatory policy for questions, issues, cases, etc. for all aspects of the AEP System.
Real Estate and Workplace Services	Real Estate and Workplace Services is responsible for areas of facilities management, office services, physical security and land management.
Regulated Commercial Operations	Commercial Operations services include coordinating the dispatch of AEP's generation fleet and engage in bulk power market activity in order to serve native load requirements and

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Affiliate Transactions

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SERVICES RENDERED BY AEPSC

GROUP/FUNCTION	DESCRIPTION
	to lower customer rates through off-system sales. Also responsible for fuel procurement, fuel contract negotiation and administration, fuel inventory management, and fuel planning and analysis.
Regulatory Services	Support of system wide regulatory and rate analysis.
Risk and Strategic Initiatives	Coordination of risk assessment, credit risk management and insurance coverage.
Supply Chain & Fleet Operations	Supply Chain and Fleet Services are responsible for fleet support, which encompasses the provision and support of vehicles and related equipment. Also provides materials management services, procurement and contracting services.
Transmission Administration	Services provided by Transmission Administration.
Transmission Asset Strategy and Policy	Executive management support of all areas of Transmission.
Transmission Field Services	Transmission Field Services is responsible

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Affiliate Transactions

Subject

SERVICES RENDERED BY AEPSC

GROUP/FUNCTION	DESCRIPTION
	for the maintenance and emergency restoration of the AEP transmission system and distribution station facilities.
Transmission Grid Development & Portfolio Services	Transmission Strategy and Business Development Services is responsible for developing and executing transmission strategy and business plans in alignment with AEP's corporate strategy.
Transmission-Engineering and Project Services	Transmission Field Services is responsible for the maintenance and emergency restoration of the AEP transmission system and distribution station facilities.
Treasury	Cash management, and financing services.

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Affiliate Transactions

Subject

Intercompany Products and Services

SUMMARY

The non-tariffed products and services provided by AEP's regulated utilities to affiliate companies and vice versa are governed by written agreements between and among the companies (see TAB **04** in this manual). The following tables describe the nature of the various transactions that are conducted with affiliates in three categories:

- products and services provided by regulated utilities to non-regulated affiliates
- products and services provided to regulated utilities by non-regulated affiliates
- products and services provided by regulated utilities to each other.

PRODUCTS AND SERVICES PROVIDED BY REGULATED UTILITIES TO NON-REGULATED AFFILIATES

The following table describes the nature of products and services provided by the AEP System's regulated utilities to non-regulated affiliates:

CATEGORY	***DESCRIPTION***
Facilities Management	Construct, operate and maintain equipment, approval of outside contracts & monitoring work of contractors.
Pole Attachments	Lease poles and towers for communication and other purposes.

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Affiliate Transactions

Subject

Intercompany Products and Services

CATEGORY	***DESCRIPTION***
Customer Accounting	Service, administer, and collect receivables sold to AEP Credit, Inc.
Land Management	Provide consulting services related to the buying and selling of real estate; including site appraisals and site maintenance services.
Corporate Services	Provide office space, furnishings, and equipment. Provide consulting services related to maintenance of owned and leased facilities.
Building Space and Office Services	Bill rent and carrying charges for building space occupied.
Equipment Rentals	Lease short-term equipment rentals.
Materials and Supplies (inventory transfers)	Provide materials from storerooms. Charges include the cost of the materials and supplies and appropriate stores overheads. Stores overheads include costs associated with purchasing and maintaining the materials and supplies inventory.

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Affiliate Transactions

Subject

Intercompany Products and Services

PRODUCTS AND SERVICES PROVIDED TO REGULATED UTILITIES BY NON-REGULATED AFFILIATES

The following table describes the nature of products and services provided to the AEP System's regulated utilities by non-regulated affiliates:

CATEGORY	***DESCRIPTION***
Testing Services (discontinued)	USTI provides environmental testing services to our generation facilities. These services provided by USTI will be billed to the regulated generation facilities at the lower of cost or market, in compliance with the asymmetric pricing rules.

PRODUCTS AND SERVICES PROVIDED BY REGULATED UTILITIES TO EACH OTHER (Including Coal Mining Subsidiaries)

The following table describes the nature of products and services provided by the AEP System's regulated utilities to each other:

CATEGORY	***DESCRIPTION***
Materials and Supplies (inventory transfers)	Materials supplied from company storerooms shall include the material cost and stores overheads. Overheads include costs associated with purchasing and maintaining materials and supplies inventory.

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Affiliate Transactions

Subject

Intercompany Products and Services

CATEGORY	***DESCRIPTION***
Equipment Maintenance	Provide personnel and services to perform regular and emergency equipment repairs (primarily for operating plant equipment).
Simulator Training	Provide personnel and facility to train power plant personnel on the operation of 1300 MW units.
Building Space and Office Services	Billing of rent and carrying charge for building space occupied.
Water Transportation, Coal and Consumables Handling, and Gypsum	Provide barging and services at transfer terminals and other coal handling facilities.
Railcar Maintenance	Billing for routine inspection and repair work on railcar hopper fleet.
Railcar Usage	Usage of railcars by other companies.
Mining (including mine shutdown costs)	Affiliated companies mine and provide coal and lignite to electric utilities on a cost reimbursement basis.
Power Coordination Agreement (power purchases and sales)	Sharing of power production and off-system sales and purchases among AEP System generating companies.

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Affiliate Transactions

Subject

Intercompany Products and Services

CATEGORY	***DESCRIPTION***
Emergency Assistance	Provide personnel to restore electric service interrupted by natural disasters.
EHV Transmission System	Sharing of costs incurred regarding the ownership, operation and maintenance of AEP's extra-high voltage (EHV) trans-mission system.
Energy Distribution System	Provide personnel and services to perform engineering, metering, drafting, line work, customer services, right-of-way maintenance work, design of construction projects, contract administration and administrative planning.
Energy Transmission	Provide personnel and services to perform transmission line work, protection & control, and station and engineering work.
Energy Delivery Support	Provide personnel and services to perform measurements, telecommunications, forestry and real estate work.

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Affiliate Transactions

Subject

Intercompany Products and Services

CATEGORY	***DESCRIPTION***
Administrative Support	Provide personnel and services to perform environmental, governmental affairs, fleet management, building services and mail services.
Hydro Plant	Provide supervision, maintenance and operation of hydro plant and associated facilities.
Joint Facilities	Share costs of operations and maintenance of jointly owned facilities(primarily generating plants and HVDC transmission facilities).
Capitalized Spare Parts	Capitalized spare parts are sold by the utilities to each other at cost.
Coal Supply	Sale of Coal to the operating companies.
Waste Disposal	Provide waste handling and landfill services
Consumables Handling	Provide Services for transloading UREA.
Coal Handling	Provides trans-loading services at Cook Terminal.
Transmission Training	Provide transmission employees with training.

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Document Number **01-03-04**

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Affiliate Transactions

Subject

MONEY POOL

SUMMARY

The AEP System Utility Money Pool and the AEP System Nonutility Money Pool are arrangements structured to meet the short-term cash requirements of their participants. The operation of the two Money Pool arrangements is designed to match, on a daily basis, the available cash and borrowing requirements of participants, thereby minimizing the need to borrow from external sources.

AUTHORITY

The AEP System Utility Money Pool and the AEP System Nonutility Money Pool operate consistently with the terms and conditions of their respective agreements. The AEP System Utility Money Pool Agreement is filed with the Federal Energy Regulatory Commission (FERC).

PARTICIPANTS

The AEP System Utility Money Pool participants are certain of AEP regulated direct and indirect subsidiaries as well as certain nonutility subsidiaries. The AEP System Nonutility Money Pool Agreement participants are certain of AEP unregulated direct and indirect subsidiaries. Each participant may withdraw any of its funds from the respective Money Pool to which it belongs at any time upon notice to American Electric Power Service Corporation (AEPSC).

AGENT

AEPSC acts as the administrative agent of the Utility and Nonutility Money Pools. As of February 24, 2016 AEPSC no longer participates in the Utility Money Pool.

FUNDING ENTITIES

AEP may engage in various types of short-term financings to fund the daily needs of the money pools. AEP Utility Funding LLC was formed to fund the Utility Money Pool

and AEP Nonutility Funding LLC was formed to fund the Nonutility Money Pool. Any funds transferred to the Money Pool will flow through the applicable Funding LLC. The Utility Funding LLC may obtain funds from external sources, or AEP. The Nonutility Funding LLC will obtain its funds from AEP. The Funding LLCs are solely financial conduits.

RULES

American Electric Power Company, Inc. (AEP), AEP Utility Funding LLC, and AEP Nonutility Funding LLC will not borrow funds from the Utility or Nonutility Money Pools or their participants.

Participants in the Nonutility Money Pool will not engage in lending and borrowing transactions with participants of the Utility Money Pool.

Each participant, except AEP and AEP Utility Funding LLC, and AEP Nonutility Funding LLC has the right to borrow from its respective Money Pool from time to time, subject to the availability of funds and other limitations. No participant is obligated to borrow from its respective Money Pool if lower cost funds can be obtained from its own external borrowing.

PROCESS

Available funds in the treasuries of the participants in the individual Utility and Nonutility Money Pools are individually "pooled" together. Within each money pool the cash position of each Money Pool participant is determined on a daily basis. The pooled funds are either loaned to other

participants within the pool or invested in short-term cash instruments.

If the cash needs of the Utility and/or Nonutility Money Pools exceed the pooled funds, additional funds are raised through external borrowings from the sale of commercial paper notes as well as certain other means to the extent permitted by law and regulatory orders.

A daily interest rate is calculated for each money pool and applied to all participant borrowings and investments.

The interest rate for the Utility Money Pool is the composite weighted-average daily effective cost incurred by AEP, and/or AEP Utility Funding LLC for short-term borrowings from external sources or an equivalent rate when there is no external borrowing.

The interest rate for the Nonutility Money Pool is the composite weighted-average daily effective cost incurred by AEP for short-term borrowings from external sources or an equivalent rate when there is no external borrowing, plus a margin if the Participant's internal credit rating is lower than that of the Leading Parties.

If surplus funds exist in the treasuries of the Utility and/or Nonutility money pools, an external investment is made on behalf of the respective money pool with the surplus.

Interest income related to external investment of surplus funds is calculated

daily and allocated back to the lending participants based on their relative contribution to the surplus.
Money Pool participants are also charged a pro rata cost of certain expenses associated with their borrowing program, including fees associated with bank lines of credit, rating agencies, and the issuing and paying agent.

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Document Number **01-03-05**

Cost Allocation Manual

Section

Affiliate Transactions

Subject

RESEARCH AND DEVELOPMENT

SUMMARY

Research and development (R&D) projects are generally managed by AEPSC on behalf of other AEP System companies. The services performed by AEPSC are billed to the respective parties through the AEPSC billing system. Every shared project is billed using one of the approved Allocation Factors (see the Appendix to this manual for a complete list of approved Allocation Factors).

In many cases, an AEP System operating company provides the site for conducting the R&D activity and/or procures the equipment and materials needed to conduct the research. In these cases, the operating company acts as the lead company for all other participants and is responsible for the payment of all costs it incurs on behalf of the other participants.

The costs incurred by the lead company are shared with and billed to the other AEP participants through a separate R&D accounting and billing process. The R&D accounting and billing process uses the same Allocation Factor for each project that AEPSC uses to bill its support costs.

PROCEDURE

Operating company billings for R&D are performed on a fully-allocated cost basis (i.e., the billings include both direct and indirect costs).

Non-Productive Pay

The cost of employee vacations, holidays, jury duty and other paid absences are accrued and loaded on to labor dollars.

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Section

Affiliate Transactions

Subject

RESEARCH AND DEVELOPMENT

Fringe benefits Procedure	The cost of fringe benefits such as pension expense is loaded on to labor dollars.
A&G OVERHEADS	Administrative and general (A&G) overheads are loaded to R&D projects in the R&D accounting and billing process based on the labor dollars charged to each project.
Direct Costs	All direct costs of a R&D project, including productive labor, are captured along with the indirect costs described above.
BILLING	The lead company of any shareable R&D project will bill its associates their respective share of the incurred R&D costs. The costs billed to the associate companies will be exclusive of any costs that are incurred by AEPSC since such costs are appropriately allocated through the AEPSC work order billing system. The lead company will retain its share of any incurred costs.

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Document Number **01-03-06**

Cost Allocation Manual

Section

Affiliate Transactions

Subject

FINANCIAL TRANSACTIONS

SUMMARY

The AEP System companies, although legally separated, operate on an integrated basis as permitted by law and regulation. Financial transactions are conducted on a regular basis in support of the integrated activities.

FINANCIAL TRANSACTIONS

The following table provides a summary of the primary financial transactions the AEP System companies conduct with each other that are not covered elsewhere in this Section of this manual:

CATEGORY	***DESCRIPTION***
Loans	Debt obligations.
Capital Contributions	Common stock purchases as well as paid-in capital transactions.
Accounts Receivables Factoring	AEP Credit, Inc. (formerly CSW Credit, Inc.) buys the accounts receivables of certain of the electric utility affiliates.
Credit Line Fees	Credit line fees are shared among AEP System companies.
Dividend Payments	Dividend payments are made by subsidiaries to their parent companies.
Real and Personal Property	Title to and/or rights in real or personal property acquired and held by an AEP affiliate as Agent for another AEP affiliate.

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Document Number **01-03-06**

Cost Allocation Manual

Section

Affiliate Transactions

Subject

FINANCIAL TRANSACTIONS

CATEGORY	***DESCRIPTION***
Employee Loans, Accrued Compensation, Employee Relocation Expenses and Other Employee-Related Items	When an employee transfers from one AEP company to an affiliate, the receiving company pays the employee's relocation expenses. In addition, any amounts due to or from the employee are transferred to the receiving company from the sending company.
Money Pool	An arrangement designed to match the available cash and borrowings requirements of participants to minimize the need for external borrowings.

NOTE: Also see Document Numbers **01-03-04**, **01-03-05** and **01-03-08** for a discussion of the AEP Money Pool, Research & Development cost sharing and Convenience Payments, respectively.

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Document Number **01-03-07**

Cost Allocation Manual

Section

Affiliate Transactions

Subject

INTELLECTUAL PROPERTY

SUMMARY

From time-to-time the unregulated companies of the American Electric Power system may enter into agreements with non-affiliated third parties for the licensing of technology developed by American Electric Power Service Corporation (AEPSC) and certain electric utility subsidiaries within the AEP System. These agreements, among other things, extend to the resale and licensing of property protected by copyright, patent or trademark laws (herein referred to as intellectual property).

TERMS AND CONDITIONS FOR USE OF INTELLECTUAL PROPERTY BY UNREGULATED COMPANIES

If an unregulated company sells or licenses to non-affiliated intellectual property developed by AEPSC or any other AEP System company, such companies shall receive a a percentage of the net profits and the unregulated company will receive a commission by having the unregulated pay the AEP System company that developed the intellectual property the amounts noted in the following table:

REVENUE SHARING PROVISIONS
1. 70% of the revenues from the intellectual property until the AEP System company that developed the intellectual property recovers its programming and development costs; and 2. 20% of such revenues thereafter.

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Document Number **01-03-07**

Cost Allocation Manual

Section

Affiliate Transactions

Subject

INTELLECTUAL PROPERTY

TERMS AND CONDITIONS FOR THE USE OF INTELLECTUAL PROPERTY DEVELOPED BY UNREGULATED COMPANIES	Intellectual property developed by an unregulated company will be made available to all associates in the AEP holding company system without charge, except for actual expenses incurred by an unregulated company in connection with making such intellectual property so available.

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Document Number **01-03-08**

Cost Allocation Manual

Section

Affiliate Transactions

Subject

SERVICE CORPORATION CONVENIENCE PAYMENTS

SUMMARY

American Electric Power Service Corporation (AEPSC) provides services to other companies in the AEP Holding Company System. To the extent possible, the expenditures incurred by AEPSC should pertain exclusively to the services it performs.

AEP POLICY

AEP's policy is to minimize AEPSC convenience payments. However, in some situations, AEPSC makes payments on behalf of other System companies as a matter of convenience. Generally, these convenience payments are made in an emergency situation or for cost-saving or timesaving purposes. The requester must recommend an allocation method for any Convenience Payment that pertains to two or more companies.

The distribution of the convenience payment among the appropriate companies will be provided by either the requester of the convenience payment or by AEPSC personnel acting on behalf of the requester. The distribution of the convenience payment can be provided on the face of the invoice to be paid, based upon anticipated benefits to be derived by the appropriate companies, or based upon existing AEPSC allocation methods. The most appropriate and/or reasonable method will be used for each specific convenience payment based on the type of transaction.

REPORTING REQUIREMENTS

Annually AEPSC is required to report the amount paid during the past calendar year for convenience payments. The required information must be included in AEPSC's annual report that is filed with the Federal Energy Regulatory Commission(FERC)on FERC Form 60.

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Document Number **02-01-01**

Cost Allocation Manual

Section

Introduction

Subject

OVERVIEW (GUIDELINES)

SUMMARY	AEP has internal (i.e., Corporate) guidelines for cost allocation and inter-company billings. Federal and state authorities, either through legislation or formal rule making, have established cost allocation methods and affiliate transaction requirements.
CORPORATE	AEP has established corporate policies and procedures for cost allocation and billing. Its cost allocation process includes both direct costs and indirect costs. Its inter-company billing process includes both direct billings to a single company and shared billings to a group or class of companies.
FEDERAL REGULATION	The Federal Energy Regulatory Commission (FERC) regulates the AEP System's cost allocation process as well as the transactions that take place among the AEP System companies. AEP prices all transactions among the affiliate companies in the AEP System in accordance with the "at cost" standard, which was carried forward by the FERC under the PUHCA 2005.
STATE COMMISSION RULES	AEP's eleven state commissions, to some degree, have established rules and regulations or other requirements relative to AEP's cost allocation practices and affiliate transactions. State commission authority in these areas, for the most part, is based on their authority to establish rates for retail customers.

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Document Number **02-02-01**

Cost Allocation Manual

Section

Corporate

Subject

OVERVIEW

SUMMARY

AEP's internal guidelines applicable to cost allocations are designed to result in a fair and equitable allocation of costs. Policies and procedures have also been formulated to meet regulatory standards both for cost allocation and affiliate transactions.

COST ALLOCATION POLICIES AND PROCEDURES

Each AEP subsidiary maintains separate books and records. Transactions are coded and processed in a manner that meets all regulatory requirements. Proper audit trails are maintained so that costs can be traced from source documents all the way through the applicable accounting and billing systems.

02-02-02

THE COST ALLOCATION PROCESS

Unless otherwise exempted, the AEP companies allocate costs between regulated and non-regulated operations, on a fully-distributed cost basis. Fully-distributed costs include all direct costs plus an appropriate share of indirect costs.

02-02-03

COST POOLING AND COST ASSIGNMENT

Indirect costs are pooled and assigned to multiple companies or company segments in accordance with the relative benefits received or by other equitable means.

02-02-04

ACCOUNT DESIGNATIONS

The operation and maintenance expense accounts in the Federal Energy Regulatory Commission's (FERC's) uniform system of accounts break functionally between regulated and non-regulated expenses.

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Document Number **02-02-01**

Cost Allocation Manual

Section

Corporate

Subject

OVERVIEW

Certain administrative and general expenses include costs that can be attributed to both regulated and non-regulated activities. Some of AEP's generation has been restructured as a competitive activity, and therefore, the power production accounts in the FERC's system of accounts become non—regulated accounts.

02-02-05

AEP AMERICAN ELECTRIC POWER

Document Number **02-02-02**

Cost Allocation Manual

Section

Corporate

Subject

COST ALLOCATION POLICIES AND PROCEDURES

SUMMARY

Cost allocation is the process of assigning a single cost to one or more company or company segments on the basis of the relative benefits received or other equitable basis. This document summarizes the underlying cost allocation policies and procedures that are applied on a corporate-wide basis by all AEP companies.

POLICIES AND PROCEDURES

AEP's cost accounting and cost allocation policies and procedures shall not result in any cost subsidies among or between regulated and non-regulated operations. Unless otherwise exempted, all affiliate transactions for services or products will be conducted at fully allocated cost. For the transfer of capital assets, fully allocated cost shall equal the net book value of the capital asset.

The term "affiliate transactions" refers to all transactions between the utility and any separate affiliate company, both regulated and non-regulated, including all transactions between a utility's regulated operations (above-the-line) and non-regulated operations (below-the-line).

Basic Goal

The basic goal of AEP's cost allocation policies and procedures are threefold:

- to ensure a fair and equitable distribution of costs among all benefiting parties
- to meet pertinent regulatory requirements
- to minimize the time and expense needed to record, audit and report transactions.

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COST ALLOCATION POLICIES AND PROCEDURES

Separate Books and Records	Each subsidiary of AEP shall maintain separate books and records and make maximum use of common accounting and business systems without violating any federal or state imposed code of conduct provisions relative to sensitive customer or non-public information.
Accounting Transactions	All financial accounting transactions will be recorded in accordance with corporate accounting policy using the appropriate chartfield values for each transaction. Each transaction will be recorded in accordance with the FERC Uniform System of Accounts as applicable to each subsidiary or affiliate.
Cross-Subsidies	AEP's cost accounting and cost allocation methods or procedures shall not result in any cost subsidies among or between regulated and non-regulated operations.
Cost Allocation	Factors to be considered in the Allocation of individual items of cost include, among other things: • the relationship of the individual cost to the benefiting company or company segments • generally accepted accounting principles • best practices • regulatory principles • reasonableness of results

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COST ALLOCATION POLICIES AND PROCEDURES

Audit Trail

A key requirement for allocating costs for affiliate transactions is the maintenance of adequate audit trails. The following audit trail standards shall be maintained for all transactions:

- vendor invoices, employee time records and expense accounts, general ledger journal entries and similar documentation will be available and accessible to adequately support the accuracy and validity of individual transactions
- all supporting documentation will be retained in accordance with the applicable regulatory requirements for records retention
- all posting to the providers' books of account or summary ledgers will be identifiable with the individual transactions that make up the total amount of the posting.

Transfer Pricing of Affiliate Transactions

The predominant pricing standard among AEP's various regulatory jurisdictions for affiliate transactions is "fully-allocated cost." However, in certain jurisdictions and instances, the substantiation of market prices may be required because of state code of conduct or other rules or regulations.

For billing purposes, non-tariff products and services either purchased by or sold by one of AEP's regulated utilities will be priced at "fully-allocated cost".

In the case of products and services, "fully-allocated cost" approximates market

value in most situations since the parties are simply sharing costs that reflect current market prices.

For the transfer of capital assets between an AEP regulated utility and an affiliate, "fully-allocated cost" shall equal the net book value of the asset (i.e., original cost less depreciation).

ACCESS TO BOOKS AND RECORDS

All lawful requests by regulators to obtain access to the books and records of an affiliate of a regulated utility for the purpose of setting the utility's cost-based rates shall be honored in a timely manner.

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Cost Allocation Manual

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Corporate

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THE COST ALLOCATION PROCESS

SUMMARY	AEP allocates costs to regulated and non-regulated operations on a fully-distributed cost basis. Fully distributed costs include all direct costs plus an appropriate share of indirect (and common) costs.
DIRECT COSTS	Direct costs can be identified with a particular activity and can be incurred on behalf of one or more companies or affiliates.
INDIRECT COSTS	Indirect costs cannot be identified with a particular activity and must be charged to the appropriate activity or activities to which they relate using relevant cost allocators. Indirect costs include, but are not limited to, corporate or business unit overheads, general and administrative overheads, and certain taxes.
COMMON AND JOINT COSTS	Common and joint costs, as distinguished from indirect costs, are costs that are of joint benefit between regulated and non-regulated business operations. These costs can include both direct and indirect costs.

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THE COST ALLOCATION PROCESS

COST EXAMPLES

The following table provides examples of the expenses included in each cost category:

Direct costs	Direct labor; direct materials
Indirect costs	Board of Directors' fees; FICA tax; interest expense; other elements of Internal Support Costs and departmental overhead.
Common costs	Depreciation or rent expense on shared buildings; the expenses incurred in operating a common payroll system

BASIC PROCESS

AEP allocates costs among regulated and non-regulated business operations following three basic steps:

1. To the maximum extent possible, within reasonable cost benefit standards, costs are collected and classified on a direct charge basis.

2. All costs, both direct and indirect, are attributed to activities (i.e., projects, products or services) which, by their very nature, are regulated, non-regulated, common or joint.

3. The costs of common or joint activities are allocated using either an output measure of the activity performed or the primary cost driver (or a relevant proxy in the absence of a primary cost driver).

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THE COST ALLOCATION PROCESS

BILLINGS TO AFFILIATES

Any costs incurred for the benefit of only one client or affiliate are billed 100% to that client or affiliate.

Any costs incurred for the benefit of more than one client or affiliate are billed to the clients or affiliates for which the related service was performed using cost-causative allocation factors of the nature described in Step 3 of the basic allocation process (see above). For example, the cost accumulated for processing payroll is allocated and billed based on the ratio of each client's or affiliate's number of employees to the total number of employees of all clients or affiliates receiving the service.

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Cost Allocation Manual

Section

Corporate

Subject

COST POOLING AND COST ASSIGNMENT

SUMMARY

The financial accounting systems used by the AEP System companies are designed to pool allocable costs in a manner that leads to a fair and equitable distribution of costs among all affiliated companies and between regulated and non-regulated operations.

UNDERLYING PRINCIPLE

The underlying principle in cost allocation is that the results must be fair and equitable. To meet this standard, the results must be reasonable and take into account the relative benefits received from each cost pool.

POOLING METHODOLOGY

In order to perform fair and equitable cost allocations, AEP's financial accounting systems are designed to capture and pool costs at three basic levels:

- direct costs are costs which can be specifically assigned to final cost objectives;
- common or joint costs are costs which apply to more than one cost objective and can be attributed to them in reasonable proportion to the benefits received; and
- overhead costs relate to the overall operations of the business and, as such, have no direct relationship to any particular cost objective.

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COST POOLING AND COST ASSIGNMENT

Sub-Pools

Common and joint costs along with overhead costs are further accumulated in various cost groupings (sub-pools). Examples include:

- salary-related costs (also known as fringes)
- compensated absences (i.e., non-productive pay)
- building costs
- technology costs
- general and administrative overhead
- construction overhead

COST ASSIGNMENT

The AEP System pools and allocates costs at each level on a legal entity basis. That is, the costs incurred by one company do not affect the level of costs allocated by another company. Separate books and records are maintained for each company.

All companies assign direct costs on a 100% basis while common or joint costs are assigned or charged to multiple cost objectives in accordance with the relative benefits received or by other equitable means. Overhead costs are charged using relatable, cost-causative factors such as labor dollars, and total cost input.

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Cost Allocation Manual

Section

Corporate

Subject

ACCOUNT DESIGNATIONS (Regulated, Non-Regulated and Joint)

SUMMARY

As required by the Commonwealth of Kentucky's House Bill No. 897 [Section 4(f)], the Cost Allocation Manual (CAM) maintained by the electric utility must provide a report that identifies whether the costs contained in each account (or sub-account) of the Uniform System of Accounts (i.e., the USoA) are attributable to regulated operations, non-regulated operations, or are joint costs in nature. A description of the methodology used to apportion the costs shall also be included. The allocation methodology must be consistent with the provisions of Section 3 of House Bill No. 897.

While this document has been prepared primarily to satisfy Kentucky's CAM requirement, the account designations included in the accompanying chart also apply to AEP's other electric utilities.

ACCOUNT DESIGNATIONS

The chart which begins on the following page identifies those USoA operation and maintenance accounts that are considered to be regulated, non-regulated or joint. The chart pertains to all of AEP's regulated utilities to the extent that they use each account. As generation becomes deregulated in certain state jurisdictions, the accounts for power production expenses will become non-regulated.

COST ALLOCATION

To the extent possible, costs are charged directly to either regulated or non-regulated operations as appropriate. Those "joint" costs that can not be directly charged are allocated between regulated and non-regulated operations based on the nature of the cost, using the appropriate

allocation basis from the List of Approved Allocation Factors used for Service Company billings.

CHART

FERC Account	Description	Reg.	Non Reg.	Joint
	Power Production Expenses			
500.0	Oper Supervision & Engineering	No	No	Yes
501.0	Fuel	No	No	Yes
502.0	Steam Expenses	No	No	Yes
503.0	Steam from Other Sources	No	No	Yes
504.0	Steam Transferred-Credit	No	No	Yes
505.0	Electric Expenses	No	No	Yes
506.0	Misc Steam Power Expenses	No	No	Yes
507.0	Rents	No	No	Yes
508.0	Oper Supplies and Expenses	No	No	Yes
509.0	Allowances	No	No	Yes
510.0	Maint Supv & Engineering	No	No	Yes
511.0	Maintenance of Structures	No	No	Yes
512.0	Maintenance of Boiler Plant	No	No	Yes
513.0	Maintenance of Electric Plant	No	No	Yes
514.0	Maintenance of Misc Steam Plt	No	No	Yes
515.0	Maintenance of Steam Production Plant	No	No	Yes
517.0	Oper Supervision & Engineering	No	No	Yes
518.0	Nuclear Fuel Expense	No	No	Yes
519.0	Coolants and Water	No	No	Yes
520.0	Steam Expenses	No	No	Yes
521.0	Steam from Other Sources	No	No	Yes
522.0	Steam Transferred-Credit	No	No	Yes
523.0	Electric Expenses	No	No	Yes
524.0	Misc Nuclear Power Expenses	No	No	Yes
525.0	Rents	No	No	Yes
528.0	Maintenance Supervision and engineering	No	No	Yes
529.0	Maintenance of Structures	No	No	Yes
530.0	Maintenance of Reactor	No	No	Yes

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ACCOUNT DESIGNATIONS (Regulated, Non-Regulated and Joint)

FERC Account	Description	Reg.	Non Reg.	Joint
	Plant Equipment			
531.0	Maintenance of Electric Plant	No	No	Yes
532.0	Maintenance of Misc Nuclear Plant	No	No	Yes
535.0	Operation Supervision and Engineering	No	No	Yes
536.0	Water for Power	No	No	Yes
537.0	Hydraulic Expenses	No	No	Yes
	Power Production Expenses (Cont'd)			
538.0	Electric Expenses	No	No	Yes
539.0	Misc Hydr Power Generation Exp	No	No	Yes
540.0	Rents	No	No	Yes
540.1	Operation Supplies and Expenses	No	No	Yes
541.0	Maintenance Supervision and Engineering	No	No	Yes
542.0	Maintenance of Structures	No	No	Yes
543.0	Maintenance of Reservoirs, Dams and Waterways	No	No	Yes
544.0	Maintenance of Electric Plant	No	No	Yes
545.0	Maintenance of Misc Hydraulic Plant	No	No	Yes
545.1	Maintenance of Hydraulic Production Plant	No	No	Yes
546.0	Operation Supervision and Engineering	No	No	Yes
547.0	Fuel	No	No	Yes
548.0	Generation Expenses	No	No	Yes
549.0	Misc Oth Pwr Gen - Gas Turbine	No	No	Yes
550.0	Rents	No	No	Yes
550.1	Operation supplies and expenses	No	No	Yes
551.0	Maint Supv & Engineering	No	No	Yes
552.0	Maintenance of Structures	No	No	Yes
553.0	Maintenance of Generating and Electric Plant	No	No	Yes
554.0	Maintenance of Misc Other Power Generation Plant	No	No	Yes

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ACCOUNT DESIGNATIONS (Regulated, Non-Regulated and Joint)

FERC Account	Description	Reg.	Non Reg.	Joint
554.1	Maintenance of Other Power Production Plant	No	No	Yes
555.0	Purchased Power	No	No	Yes
556.0	Sys Control & Load Dispatching	No	No	Yes
557.0	Other Expenses	No	No	Yes
	Transmission Expenses			
560.0	Oper Supervision & Engineering	Yes	No	No
561.1	Load Dispatch--Reliability	Yes	No	No
561.2	Load dispatch—Monitor and operate transmission system	Yes	No	No
561.3	Load dispatch—Transmission service and scheduling	Yes	No	No
561.4	Scheduling system control and dispatch services	No	No	Yes
561.5	Reliability planning and standards development	Yes	No	No
561.6	Transmission service studies	Yes	No	No
561.7	Generation interconnection studies	Yes	No	No
561.8	Reliability planning and standards development services	Yes	No	No
562.0	Station Expenses	Yes	No	No
563.0	Overhead Line Expenses	Yes	No	No
564.0	Underground Line Expenses	Yes	No	No
565.0	Transmssion of Elect by Others	Yes	No	No
566.0	Misc Transmission Expenses	Yes	No	No
567.0	Rents	Yes	No	No
567.1	Operation Supplies and Expenses	Yes	No	No
568.0	Maint Supv & Engineering	Yes	No	No
569.0	Maintenance of Structures	Yes	No	No
569.1	Maintenance of computer hardware	Yes	No	No
569.2	Maintenance of computer software	Yes	No	No
569.3	Maintenance of communication equipment	Yes	No	No

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ACCOUNT DESIGNATIONS (Regulated, Non-Regulated and Joint)

FERC Account	Description	Reg.	Non Reg.	Joint
569.4	Maintenance of miscellaneous regional transmission plant	Yes	No	No
570.0	Maint of Station Equipment	Yes	No	No
571.0	Maintenance of Overhead Lines	Yes	No	No
572.0	Maint of Underground Lines	Yes	No	No
573.0	Maint of Misc Transmssion Plt	Yes	No	No
574.0	Maintenance of Transmssion Plant	Yes	No	No
	Regional Market Expenses			
575.1	Operation Supervision	Yes	No	No
575.2	Day-ahead and real-time market facilitation	Yes	No	No
575.3	Transmission rights market facilitation	Yes	No	No
575.4	Capacity market facilitation	Yes	No	No
575.5	Ancillary services market facilitation	Yes	No	No
575.6	Market monitoring and compliance	Yes	No	No
575.7	Market facilitation, monitoring and compliance services	Yes	No	No
575.8	Rents	Yes	No	No
576.1	Maintenance of structures and improvements	Yes	No	No
576.2	Maintenance of computer hardware	Yes	No	No
576.3	Maintenance of computer software	Yes	No	No
576.4	Maintenance of communication equipment	Yes	No	No
576.5	Maintenance of miscellaneous market operation plant			
	Distribution Expenses			
580.0	Oper Supervision & Engineering	Yes	No	No
581.0	Load Dispatching	Yes	No	No

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Subject

ACCOUNT DESIGNATIONS (Regulated, Non-Regulated and Joint)

FERC Account	Description	Reg.	Non Reg.	Joint
581.1	Line and Station Expense	Yes	No	No
582.0	Station Expenses	Yes	No	No
583.0	Overhead Line Expenses	Yes	No	No
584.0	Underground Line Expenses	Yes	No	No
585.0	Street Lighting & Signal Sys Exp	Yes	No	No
586.0	Meter Expenses	Yes	No	No
587.0	Customer Installations Exp	Yes	No	No
588.0	Miscellaneous Distribution Exp	Yes	No	No
589.0	Rents	Yes	No	No
590.0	Maint Supv & Engineering	Yes	No	No
591.0	Maintenance of Structures	Yes	No	No
592.0	Maint of Station Equipment	Yes	No	No
592.1	Maintenance of Structures and Equipment	Yes	No	No
593.0	Maintenance of Overhead Lines	Yes	No	No
594.0	Maint of Underground Lines	Yes	No	No
594.1	Maintenance of Lines	Yes	No	No
595.0	Maint of Line Transformers	Yes	No	No
	Distribution Expenses (Cont'd)			
596.0	Maint of Street Lighting & Signal Systems	Yes	No	No
597.0	Maintenance of Meters	Yes	No	No
598.0	Maint of Misc Distribution Plt	Yes	No	No
	Customer Accounts Expenses			
901.0	Supervision - Customer Accts	No	No	Yes
902.0	Meter Reading Expenses	No	No	Yes
903.0	Cust Records & Collection Exp	No	No	Yes
904.0	Uncollectible Accounts	No	No	Yes
905.0	Misc Customer Accounts Exp	No	No	Yes
	Customer Services and Informational Expenses			
907.0	Supervision - Customer Service	No	No	Yes

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Subject

ACCOUNT DESIGNATIONS (Regulated, Non-Regulated and Joint)

FERC Account	Description	Reg.	Non Reg.	Joint
908.0	Customer Assistance Expenses	No	No	Yes
909.0	Information & Instruct Advertising Exp	No	No	Yes
910.0	Misc Cust Svc & Informational Exp	No	No	Yes
	Sales Expenses			
911.0	Supervision - Sales Expenses	No	No	Yes
912.0	Demonstrating & Selling Exp	No	No	Yes
913.0	Advertising Expenses	No	No	Yes
916.0	Miscellaneous Sales Expenses	No	No	Yes
	Administrative and General Expenses			
920.0	Administrative & Gen Salaries	No	No	Yes
921.0	Office Supplies and Expenses	No	No	Yes
923.0	Outside Services Employed	No	No	Yes
924.0	Property Insurance	No	No	Yes
925.0	Injuries and Damages	No	No	Yes
926.0	Employee Pensions & Benefits	No	No	Yes
928.0	Regulatory Commission Exp	No	No	Yes
930.1	General Advertising Expenses	No	No	Yes
930.2	Misc General Expenses	No	No	Yes
931.0	Rents	No	No	Yes
935.0	Maintenance of General Plant	No	No	Yes

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Cost Allocation Manual

Section

Federal Regulation

Subject

OVERVIEW

SUMMARY

Effective February 8, 2006, the Public Utility Holding Company Act of 1935 was repealed. Jurisdiction over certain holding company related activities has been transferred to the Federal Energy Regulatory Commission under the Public Utility Holding Company Act of 2005.

FERC REGULATION

The business of transmitting and selling electric energy in interstate commerce is regulated through Part II of the Federal Power Act.

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Cost Allocation Manual

Section

Federal Regulation

Subject

FERC Regulation

SUMMARY

The transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce is regulated by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act.

PUHCA 2005

The Energy Policy Act of 2005 repealed the Public Utility Holding Company Act of 1935 effective February 8, 2006 and replaced it with the Public Utility Holding Company Act of 2005. With the repeal of PUHCA 1935, the Securities and Exchange Commission no longer has jurisdiction over the activities of registered holding companies. Jurisdiction over certain holding company related activities has been transferred to the Federal Energy Regulatory Commission. Specifically, FERC has jurisdiction over the issuances of securities of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both FERC and state regulators will be permitted to review the books and records of any company within a holding company system. FERC also has jurisdiction over certain affiliate transactions. As part of the implementation of the Public Utility Holding Company Act of 2005, FERC has adopted rules addressing these various issues. The pertinent rules may be found at 18 C.F.R. Part 35, Subparts H and I, and Part 366.

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Cost Allocation Manual

Section

State Commission Rules

Subject

OVERVIEW

SUMMARY

AEP's state commissions have established certain rules and requirements relative to affiliate transactions. The requirements generally fall into four broad categories:

- they need to maintain a cost allocation manual or other documentation
- transfer pricing rules
- reporting requirements
- audit requirements.

ARKANSAS

Arkansas requirements can be found in Arkansas Public Service Commission Order 7 of Docket 06-112-R, dated May 25, 2007.

02-04-02

INDIANA

Indiana's requirements can be found in the Indiana Code as well as various orders of the Indiana Utility Regulatory Commission.

02-04-03

KENTUCKY

Kentucky's requirements are contained in Kentucky Revised Statutes (KRS) 278.2201 thru 278.2219; Kentucky Public Service Commission Regulation 807KAR 5:080 and in various orders of the Kentucky Public Service Commission.

02-04-04

LOUISIANA

Louisiana's requirements can be found in the Louisiana Public Service Commission's Order No. U-23327, dated September 16, 1999, subject to the conditions set forth in the Stipulation and Settlement attached as Appendix A to the Order.

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State Commission Rules

Subject

OVERVIEW

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MICHIGAN

Michigan's requirements are contained in various orders of the Michigan Public Service Commission, including its Order Approving Settlement Agreement dated December 16, 1999, in Case No. U-12204, and its Opinion and Order, dated December 4, 2000, in Case No. U-12134, and its Opinion and Order, dated July 9, 2020 and October 29, 2020, in Case No. U-18361.

02-04-06

OHIO

Ohio's requirements are captured in the corporate separation rules adopted by the Public Utilities Commission of Ohio in Ohio Admin. Code Chapter 4901:1-37, and in various orders of the Commission.

02-04-07

OKLAHOMA

Oklahoma's requirements are focused on the Oklahoma Corporation Commission's ability to access the books and records of Public Service Corporation of Oklahoma and its AEP affiliates as stated in the Stipulation, dated as of April 16, 1999, in Cause No. PUD 980000444.

02-04-08

TENNESSEE

Tennessee has no specific rules and requirements applicable to cost allocations and affiliate transactions.

02-04-09

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State Commission Rules

Subject

OVERVIEW

TEXAS

Texas' requirements to a large degree are contained in §36.058 of the Texas Public Utility Regulatory Act and the rules of the Public Utility Commission of Texas.

02-04-10

VIRGINIA

Virginia's requirements can be found in the Code of Virginia and in the regulations and in orders of the Virginia State Corporation Commission.

02-04-11

WEST VIRGINIA

West Virginia's requirements can be found in the West Virginia Code and in orders of the Public Service Commission of West Virginia.

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Cost Allocation Manual

Section

State Commission Rules

Subject

ARKANSAS RULES AND REQUIREMENTS

SUMMARY

The Arkansas Public Service Commission adopted Affiliate Transaction Rules May 25, 2007. The purpose of the rules is to ensure that all transactions among or between a public utility and any affiliates or divisions do not result in rates which are unreasonable and in violation of Arkansas statutes; to ensure that the rates charged by public utilities do not provide any subsidy to affiliates or divisions of the public utility which are involved in non-utility activities or which provide services to the public utility; to prevent anti-competitive behavior, and market manipulation or market power; and to prevent financial risk to rate-regulated public utility operations which may arise from business endeavors of an unregulated affiliate.

The following summarizes the Affiliate Transaction Rules as adopted.

DOCUMENTATION REQUIREMENTS

The Commission's documentation requirements applicable to affiliate transactions are provided in the table below:

SUBJECT	REQUIREMENT
Record Keeping Rule IV	A public utility is to keep books and records separately from the books and records of its affiliates and to maintain such books and records in accordance with applicable rules and orders of the Commission, and with Generally Accepted Accounting

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State Commission Rules

Subject

ARKANSAS RULES AND REQUIREMENTS

SUBJECT	REQUIREMENT
	Principles as amended. Such books and records shall contain all information necessary to identify all affiliate transactions in which a public utility participated; and identify and allocate or impute all revenues and costs (both direct and indirect) associated with all such affiliate transactions. Upon the creation of a new affiliate that will participate with a public utility, the utility shall, no later than 60 days after the creation of the affiliate, notify the Commission by letter to the Secretary of the Commission of the creation of the new affiliate, and the notice shall include an explanation of how the public utility will implement these rules with respect to the new affiliate.
	Each public utility shall maintain, for at least five years, records of each affiliate transaction in which it participated and the records shall: a. be made contemporaneously with

SUBJECT	REQUIREMENT
	each affiliate transaction; b. be in a readily retrievable format; and c. include, for each affiliate transaction: 1. identify of the affiliate; 2. commencement and termination dates of the transaction; 3. description of the affiliate transaction, including the nature and quantity of value provided and received; 4. the dollar amount of the transaction and the manner in which such dollar amount was calculated; 5. all other terms of the transaction; 6. the direct and indirect costs associated with the transaction, including any allocation formula used to attribute indirect costs; 7. all information necessary to verify compliance with the rules and the accuracy of amounts

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Section

State Commission Rules

Subject

ARKANSAS RULES AND REQUIREMENTS

SUBJECT	REQUIREMENT
	stated, i.e. invoices, vouchers, communications, journal entries, workpapers, information supporting the price of each transaction, including but not limited to the cost and allocation method of the transaction and when the cost was the result of a competitive bidding process, the market price and basis for the market price; 8. be summarized and filed with the Commission as part of the annual report. Unless otherwise ordered by the Commission, a copy of FERC Form 60, Annual Report of Centralized Service Companies, may be filed.
	Each public utility shall file contemporaneously with its annual report a summary report indicating the aggregate dollar amount of all transactions described in Rule III.G.(1), (2), (3), and

SUBJECT	REQUIREMENT
	(4) which the utility has conducted with each utility, including the name of each such affiliate.
	Each public utility is to maintain, update annually, train its employees in, and (within 120 days following the effectiveness of these rules, and thereafter, to the extent of material changes, in each annual report) file with the Commission, written procedures which ensure compliance with the rules, such procedures shall include, at a minimum: a. all internal rules, practices, financial record keeping requirements, and other policies governing affiliate transactions among or between the public utility and its affiliates; b. the names and addresses of all the public utility's affiliates; c. an organizational chart depicting the ownership relationships between the public utility and those affiliates that participate in affiliate transactions with the public utility; d. a description of the types of assets, goods

SUBJECT	REQUIREMENT
	and services provided in any existing affiliate transaction lasting more than one year; and e. a cost allocation manual or other description of the method used to determine compensation in affiliate transactions
Commission Access	The Commission shall have access to all books and records of a public utility and its affiliate to the extent such access is relevant to determining compliance with all applicable Arkansas statutes and rules or establishing rates subject to the Commission's jurisdiction.

ALLOCATION OF COSTS AND REVENUES

The Commission's rules for the allocation of certain costs and revenues related to affiliate transactions are provided in the table below:

SUBJECT	REQUIREMENTS
Affiliate Financial Transactions Rule IV	Except as provided otherwise in the Rules or in other applicable law, a public utility shall not engage in any affiliate transaction in which the public utility: 1. provides to or shares with any affiliate any financial resource or financial benefit,

SUBJECT	REQUIREMENTS
	including, but not limited to any loan, extension of credit, guarantee or assumption of debt, indemnification, pledge of collateral; or encumbrance of or restriction on the disposition of any public utility; or 2. incurs any debt for purposes of investing in, or otherwise supporting, any business other than the provision of public utility service in Arkansas.
	A public utility may obtain financial resources from an affiliate for public utility purposes, provided that the cost to the public utility of such financial resource does not exceed the lower of market price or the affiliate's fully allocated cost.
	This part of the rule shall not apply to or prohibit any of the following unless the Commission finds, after notice and hearing, unless waived by the parties, and consistent with applicable law, that the arrangement is not consistent with the

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	purposes of the rules: 1. An inter-affiliate financial transaction integral to an affiliate transaction for goods or services to and consistent with Rule V (Affiliate Transactions Other than Financial Transactions); 2. Payment of dividends by a public utility to affiliates that own stock in such public utility; 3. Transactions in connection with the factoring of accounts receivable, the creation and use of special purpose financing entities, and the creation and use of money pool or cash management arrangements, subject to safeguards to prevent cross-subsidization and unauthorized pledges or encumbrances of public utility assets; 4. Any loan, extension of credit, guarantee, assumption of debt, restriction on disposition of assets, indemnification, investment, or pledge of assets by public utility

SUBJECT	REQUIREMENTS
	for the purpose of supporting the utility related business activities of an affiliate; 5. Any debt incurred by a public utility, including debt that imposes any encumbrance on, or any restriction placed on the disposition of any assets of, the public utility for the purpose of supporting the utility related business activities of an affiliate; 6. Receipt by a public utility of capital contributions or proceeds from the sale of common stock to its parent holding company; 7. Receipt by a public utility of financial resources from an affiliate for any non-public utility purpose, provided that the cost to the public utility of such resources shall not be recovered from the public utility's customers in Arkansas; 8. Any financing arrangement involving a public utility and any affiliate that was in

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	existence as of the effective date of the rules; provided that the public utility files with the Commission a description of each such arrangement involving a public utility and any affiliate having an annual value or amount in excess of $350,000 and such filing is received within 120 days of the effective date of the rules; 9. Any other affiliate transaction proposed by a public utility, provided that the public utility first files with the Commission an application for approval of such proposed affiliate financial transaction including a detailed description thereof and any relevant supporting documentation, and the Commission finds, after notice and hearing, unless waived by the partied, on such application, that the proposed affiliate financial transaction is consistent with the purposes of the rules.
Affiliate	With respect to an affiliate

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Transactions other than Financial Transactions Rule V	transaction involving assets, goods, services, information having competitive value, or personnel, a public utility shall not: 1. receive anything of value, unless the compensation paid by the public utility does not exceed the lower of market price of fully allocated cost of the item received; and, 2. provide anything of value, unless the compensation received by the public utility is no less than the higher of market price or fully allocated cost of the item provided.
	This rule shall not apply to: 1. exchanges of information (a)necessary to the reliable provision of public utility service by a public utility, provided such exchange occurs consistently with guidelines published by the utility and applied equally to affiliates and non-affiliates; (b) required by or necessary to comply with federal statutes or regulations; or (c)between or among a public utility, its

SUBJECT	REQUIREMENTS
	parent holding company, a service company and any affiliated rate-regulated utility in another State. 2. The provision of shared corporate support services, at fully allocated cost, between or among a public utility and any affiliate, including a service company. 3. The provision, at fully allocated cost, of assets, goods, services, or personnel between or among a public utility and a affiliated rate-regulated utility in another State. 4.The provision of assets, goods, services, information having competitive value, or personnel, at a price determined by competitive bidding or pursuant to a regulatory filed or approved tariff or contract. 5. Any other affiliate transaction proposed by a public utility to be exempted from the rule provided that the public utility first files with the Commssion an application for an exemption of such proposed affiliate transaction from the

SUBJECT	REQUIREMENTS
	requirements of the rule, including a detailed description of the proposed transaction and any relevant supporting documentation, and the Commission finds, after notice and hearing, that the exemption is consistent with the purposes of the rules.

COMPLIANCE REQUIRIEMENTS

The Commission's compliance requirements applicable to the affiliate transactions are provided in the table below:

SUBJECT	REQUIREMENT
Annual Certification	No later than June 1 of each year, each public utility shall file with the Commission a notice, signed by both the public utility's president or chief executive officer and its chief financial offices, certifying the public utility's compliance with these rules in the prior year; and other annual information and reports required under the rules.
	The Commission may at any time initiate a proceeding against a public utility to determine whether a reasonable basis exists that the public utility is out of compliance with the rules.

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	If the Commission, after notice and hearing, makes such determination, the Commission may require the public utility to engage an independent accountant (which, at the public utility's election, may be the accountant that regularly audits the public utility's financial statements) to conduct Agreed Upon Procedures to review identified accounting entries, methods or procedures used by the public utility in connection with these rules. A work plan outlining such Agreed Upon Procedures, together with such letters or acknowledgements as shall be reasonably required by the accountant in connection with such engagement, shall be developed by the public utility and filed with the Commission for approval. Upon review of the information provided by such independent accountant after undertaking, the Commission may order the public utility to make changes in its accounting methods or procedures found by the Commission in to be reasonably necessary to ensure future compliance with

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	these Rules.

OTHER REQUIREMENTS – Additional requirements applicable to affiliate transactions are provided in the table below:

SUBJECT	***REQUIREMENT***
Bond Rating Downgrades Rule VII	This rule applies to any public utility that has a separate, stand-alone bond rating by Standard and Poor's or Moody's, and that has affiliates, other than utility related businesses, with assets whose total book value exceeds ten percent of the book value of the public utility's assets. If a public utility's bond ratings are downgraded to a Standard and Poor's rating of BB+ or lower, or to a Moody's rating of Ba1 or lower, such utility shall notify the Commission within 30 days of such downgrading. The public utility will provide the Commission a copy of publicly released information about such rating downgrade and such other information as the Commission requests. If the Commission finds, after notice and opportunity for hearing, that the public

	utility's downgrade would not have occurred but for one or more relationships between such public utility and one or more affiliates, then the Commission may impose remedies designed to insulate the public utility and its customers from any diminution in the public utility's ability to carry out its obligation to serve at reasonable rates.
Utility Ownership of Non-utility Business Rule VIII	A public utility shall not engage in a non-utility business other than a utility related business if the total book value of the non-utility assets owned by the utility exceeds 10 percent of the book value of the total assets of the public utility and all its affiliates. This rule does not apply to or prohibit a public utility or any affiliate thereof from continuing to engage in any non-utility business existing as of the effective date of these rules; provided the public utility files with the commission a description of such non-utility business existing as of the effective date of these rules and such filing is received within 120 days of the effective date of these rules.

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	Each public utility or its public utility holding company shall file an annual report with the Commission in accordance with the rules that includes: 1. a certification by the president of the public utility that the public utility is in compliance with this section ;and 2. all financial information necessary for the Commission to determine the utility is complying with the requirements of the rules.
EXEMPTIONS Rule XI	Any utility may petition for exemption from any of the rules on the basis that application of the rule would not be in the public interest. Any existing financial arrangements, provision of corporate services or other affiliate relationship which could be deemed to be in violation of these rules will be allowed to continue for a period of one year from adoption of these rules in order to allow the utilities involved to seek an exemption from the application of these rules for those existing circumstances
MISCELLANEOUS Rule X	The costs of any affiliate transaction found to be inconsistent with these rules

	shall be adjusted in a ratemaking proceeding to be consistent with these rules.

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INDIANA RULES AND REQUIREMENTS

SUMMARY

Indiana's rules and requirements applicable to cost allocations and affiliate transactions can be found in the Indiana Code and in the Indiana Utility Regulatory Commission's (the IURC's, or the Commission's) order, dated April 26, 1999, in Cause No. 41210, including the Stipulation and Settlement Agreement which is attached to the order as Exhibit A, as well as other orders of the Commission.

Cause No. 41210 covers the IURC's investigation of the proposed merger of American Electric Power Company, Inc. and Central and South West Corporation. Section 8 of the Stipulation and Settlement Agreement provides for Affiliate Standards between the regulated and non-regulated affiliates of the merged company.

DOCUMENTATION REQUIREMENTS

The IURC's documentation requirements for affiliate transactions are captured in the following table:

SUBJECT	***REQUIREMENT***
Separate Books and Records	Each AEP Operating Company shall maintain, in accordance with generally accepted accounting principles, books, records and accounts that are separate from the books, records and accounts of its affiliates, consistent with Part 101 – Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act. [Section 8.B.]

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SUBJECT	***REQUIREMENT***
Cost Allocation Documentation	An AEP operating company which provides both regulated and non-regulated services or products, or an affiliate which provides services or products to an AEP operating company, shall maintain documentation in the form of written agreements, an organization chart of AEP (depicting all affiliates and AEP operating companies), accounting bulletins, procedure and work order manuals, or other related documents, which describe how costs are allocated between regulated and non-regulated services or products.[Section 8.P.]
Employee Movements	AEP shall document all employee movement between and among all affiliates. Such information shall be made available to the IURC and consumer advocate upon request. [Section 8. G.]
Itemized Billing Statements	Any untariffed, non-utility service provided by an AEP operating company or affiliated service company to any affiliate shall be itemized in a billing statement pursuant to a written contract or written arrangement. The AEP

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SUBJECT	***REQUIREMENT***
Itemized Billing Statements (Cont'd)	operating company and any affiliated service company shall maintain and keep available for inspection by the Commission copies of each billing statement, contract and arrangement between the AEP operating company or affiliated service company and its affiliates that relate to the provision of such untariffed non-utility services. [Section 8.E.] Goods and services provided by a non-utility affiliate to an AEP operating company shall be by itemized billing statement pursuant to a written contract or written arrangement. The operating company and non-utility affiliate shall maintain and keep available for inspection by the Commission copies of each billing statement, contract and arrangement between the operating company and its non-utility affiliates that relate to the provision of such goods and services in accordance with the Commission's applicable retention requirements. [Section 8.F.]

[Source: Stipulation and Settlement Agreement

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in Cause No. 41210]

TRANSFER PRICING

Transactions between the regulated electric utility and its affiliates shall adhere to the affiliate standards included in the following table:

SUBJECT	***REQUIREMENT***
Guiding Principles	The financial policies and guidelines for transactions between the regulated utility and its affiliates shall reflect the following principles: 1. An AEP operating company's retail customers shall not subsidize the activities of the operating company's non-utility affiliates or its utility affiliates. [Section 8.A.1.] 2. An AEP operating company's costs for jurisdictional rate purposes shall reflect only those costs attributable to its jurisdictional customers. [Section 8.A.2.] 3. These principles shall be applied to avoid costs found to be just and reasonable for ratemaking purposes by the Commission being left unallocated or stranded

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Guiding Principles (Cont'd)	between various regulatory jurisdictions, resulting in the failure of the opportunity for timely recovery of such costs by the operating company and/or its utility affiliates; provided, however, that no more than one hundred percent of such cost shall be allocated on an aggregate basis to the various jurisdictions. [Section 8.A.3.] 4.An AEP operating company shall maintain and utilize accounting systems and records that identify and appro-priately allocate costs between the operating company and its affiliates, consistent with these cross-subsidization principles and such financial policies and guidelines. [Section 8.A.4.]
Asset Transfers	Asset transfers between an AEP operating company and a non-utility affiliate shall be at fully distributed costs in accordance with current SEC issued requirements or other statutory requirements if

SUBJECT	REQUIREMENT
	the SEC has no jurisdiction. [Section 8.C.]

[Source: Stipulation and Settlement Agreement in Cause No. 41210]

REPORTING REQUIREMENTS

The Stipulation and Settlement Agreement in Cause No. 41210 provides in part that the IURC may establish reporting requirements regarding the nature of inter-company transactions concerning the operating company and a description of the basis upon which cost allocations and transfer pricing have been established in these transactions. [Section 8.W.]

AUDIT REQUIREMENTS

The independent audit requirement regarding the merger has expired. I&M/AEP was required to conduct biennial audits for 8 years after the merger. The final audit was submitted to the Indiana Utility Regulatory Commission on December 29, 2008.

OTHER REQUIREMENTS

The Stipulation and Settlement Agreement contains other requirements related to affiliate transactions some of which are listed here:

- Thirty days prior to filing any affiliate contract (including service agreements) with the Securities and Exchange Commission or the Federal Energy Regulatory Commission the AEP operating company shall submit to the Commission a copy of the proposed filing. [Section 8.

T.]

- AEP will provide the Commission with notice at least 30 days prior to any filings that propose new allocation factors with the SEC. [Section 6]
- AEP shall designate an employee who will act as a contact for the Commission and consumer advocates seeking data and information regarding affiliate transactions and personnel transfers. Such employee shall be responsible for providing data and information requested by the Commission for any and all transactions between the jurisdictional operating company and its affiliates, regardless of which affiliate(s), subsidiary(ies) or associate(s) of the AEP operating company from which the information is sought. [Section 8.Q.]

OTHER REQUIREMENTS (con't)

The Indiana Code [§8-1-2-49] states, in part, that no management, construction, engineering, or similar contract with any affiliated interest shall be effective unless it shall first have been filed with the Commission. If it is found that any such contract is not in the public interest, the Commission, after investigation and a hearing, is authorized to disapprove the contract.

On September 28, 2016, the Indiana Utility Regulatory Commission issued General Administrative Order GAO 2016-5 which provides that Affiliate contract should do the following:
(a) Include the following terms:
(1) A definite termination date, not more than

five (5) years from the effective date of the contract.
(2) Notice that the contract, pursuant to IC 8-1-2-49(2), shall not be effective until it is filed with the Commission.
(b) Exclude the following terms:
(1) A provision that provides for an automatic contract renewal or renewal without notice to all contracting parties and the Commission.
(2) A provision that provides for an effective date that is prior to filing with the Commission.

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KENTUCKY RULES AND REQUIREMENTS

SUMMARY

Kentucky's rules and requirements applicable to cost allocations and affiliate transactions are contained in Kentucky Revised Statues, (KRS) 278.2201 thru 278.2219; Kentucky Public Service Commission Regulation 807KAR 5:08 and in certain orders of the Kentucky Public Service Commission (the Commission).

CAM REQUIREMENTS

The following table summarizes Kentucky's Cost Allocation Manual (CAM) requirements:

SUBJECT	***REQUIREMENT***
Summary	Any utility that engages in a non-regulated activity, whose revenue exceeds 2% of the utility's total revenue or $1,000,000 annually, shall develop and maintain a CAM. [KRS278.2203 (4) (a)]
"CAM" Definition	CAM means a cost allocation manual; that is, an indexed compilation and documentation of a company's cost allocation policies and related procedures. [KRS 278.010 (20)]
Contents	The CAM shall contain the following information for a utility's jurisdictional operations in the Commonwealth of Kentucky: (a) A list of regulated and non-regulated divisions within the utility; (b) A list of all regulated and non-regulated affiliates of the utility to which the

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Contents (Cont'd)	utility provides services or products and where the affiliates provide non-regulated activities as defined in [KRS278.2205 (2) (a) (b)]; (c) A list of services and products provided by the utility, an identification of each as regulated or non-regulated, and the cost allocation method generally applicable to each category; [KRS278.2205 (2) (c)]; (d) A list of incidental, non-regulated activities that are reported as regulated activities in accordance with the provisions pf [LRS278.2205 (2) (d)]; (e) A description of the nature of transactions between the utility and the affiliate; and [KRS278.2205 (2) (e)]; (f) For each FERC account and sub-account, a report that identifies whether the account contains costs attributable to regulated operations and non-regulated

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Contents (Cont'd)	operations. The report shall also identify whether the costs are joint costs that cannot be directly identified. A description of the methodology used to apportion each of these costs shall be included and the allocation methodology shall be consistent with cost allocation methodologies set out in KRS 278.2203. [KRS278.2205 (2) (f)]
Filing Requirements	Within 270 days of the effective date of July 14, 2000, the utility shall file: (a) A statement with the Commission that certifies the CAM has been developed and will be adopted by manage-ment effective with the beginning of the next calendar year. The statement shall be signed by an officer of the utility; and (b) One copy of the CAM. [KRS278.2205 (3) (a)-(b)]
Changes	Within 60 days of any material change in matters required to be listed in the CAM, the utility shall amend the CAM to reflect the

SUBJECT	REQUIREMENT
	change. [KRS278.2205 (4)]
Public Inspection	The CAM shall be available for public inspection at the utility and at the Commiss-ion. [KRS278.2205 (5)]
Rate Proceedings	The CAM shall be filed as part of the initial filing requirement in a proceeding involving an application for an adjustment in rates pursuant to KRS 278.190. [KRS278.2205(6)]

TRANSFER PRICING

KRS278.2207 thru KRS278.2219 contains very specific instructions on the pricing of assets, services and products transferred between the utility and its affiliates, as captured in the following table:

SUBJECT	REQUIREMENT
Summary	A utility shall not subsidize a non-regulated activity provided by an affiliate or by the utility itself. Utilities must keep separate accounts and allocate costs in accordance with procedures established by the Commission. [KRS278.2201]
Pricing Rules	The terms for transactions between a utility and its affiliates shall be in accordance with the following: (a) Services and products provided to an affiliate by the utility pursuant to a tariff shall be at

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SUBJECT	***REQUIREMENT***
Pricing Rules (Cont'd)	the tariffed rate, with nontariffed items priced at the utility's fully distributed cost but in no event less than market, or in compliance with the utility's existing United States Department of Agriculture (USDA), Securities and Exchange Commission (SEC), or Federal Energy Regula-tory Commission (FERC) approved cost allocation methodology. [KRS278.2207 (1) (a)] (b) Services and products provided to the utility by an affiliate shall be priced at the affiliate's fully-distributed cost but in no event greater than market or in compliance with the utility's existing USDA, SEC, or FERC approved cost allocation methodology. [KRS278.2207 (1) (6)] *NOTE: A utility may file an application with the commission requesting a deviation from the requirements of this section for a particular transaction or class of transactions. The utility shall have the*

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SUBJECT	***REQUIREMENT***
Pricing Rules (Cont'd)	*burden of demonstrating that the requested pricing is reasonable. The commission may grant the deviation if it determines the deviation is in the public interest. Nothing in this section shall be construed to interfere with the commission's requirement to ensure fair, just, and reasonable rates for utility services. [IRS278.2219 92)]*

AFFILIATE TRANSACTION REPORTING REQUIREMENTS

Kentucky Public Service Commission and the Commission's orders in Case Nos. 97-309 and 99-149 contain very specific reporting requirements for affiliate transactions.

Regulation 807KAR5:080

In addition to the CAM reporting requirements established by KRS 278.2201 thru 278.2219 as noted above, PSC Regulation 807 KAR 5:080 requires the utility to inform the Commission of new non-regulated activities begun by itself or by the utility's affiliate within a timeframe to be established by the Commission [807KAR 5:080 Section 4].

Also, the Commission may require the utility to file annual reports of information related to affiliate transactions when necessary to monitor compliance with the transaction guidelines contained in KRS278.2205 [807KAR 5:080 Section 2]

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Case 97-309

In Case 97-309 involving the approval of affiliate transactions between KPCO and AEPC (as outlined above), the Commission has ordered KPCO to file an annual report that lists all transactions with AEPC that describes the parties involved, the assets transferred, the services provided and the transaction prices. The report should also specify for each transaction whether the price was based on cost or market and, if market, how the market price was determined.

Case 99-149

The Commission's order in Case No. 99-149, dated June 14, 1999, related to the proposed merger of American Electric Power Company, Inc. (AEP) and Central and South West Corporation established specific reporting requirements for KPCO, its parent company (i.e., AEP) and related subsidiaries. While the Commission's order in Case No. 99-149 has been superseded by KRS 278.2201 thru KRS278.2219 and Ky PSC Regulation 807KAR5:080, dated July 14, 2000, the periodic reports required by the Commission's June 1999 order remain in effect. The following table provides details of the specific reporting requirements:

SUBJECT	***REQUIREMENT***
Periodic Reports [Case No. 99-149, Page 10]	1. Annual financial statements of AEP should be furnished to the Commission, including consolidating adjustments of AEP and its subsidiaries with a brief explanation of each adjustment and all

SUBJECT	***REQUIREMENT***
	periodic reports filed with the SEC. 2. All subsidiaries should prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. 3. The financial statements for any non-consolidated subsidiaries of AEP should be furnished.
Annual Reports [Case No. 99-149, Page 11 ¶1,2]	1. A general description of the nature of inter-company transactions shall be provided with specific identification of major transactions, and a description of the basis upon which cost allocations and transfer pricing have been established. This report should discuss the use of the cost or market standard for the sale or transfer of assets, the allocation factors used, and the procedures used to determine these factors if they are different from the procedures used in prior years.

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SUBJECT	***REQUIREMENT***
Annual Reports [Case No. 99-149, Page 11 ¶1,2] (Cont'd)	2. A report that identifies professional personnel transferred from KPCO to AEP or any of its non-utility subsidiaries shall be provided to the Commission. This report should include a description of the duties performed by the employee while employed by KPCO and to be performed subsequent to transfer. 3. AEP should file on an annual basis a report detailing KPCO's proportionate share of AEP's total operating revenues, operating and maintenance expenses, and number of employees.
Special Reports [Case No. 99-149, Pages 11-12]	1. AEP should file any contracts or other agreements concerning the transfer of utility assets or the pricing of inter-company transactions with the Commission at the time the transfer occurs. 2. AEP should also file the following special reports: • An annual report of the number of employees of AEP and each subsidiary on the

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SUBJECT	***REQUIREMENT***
	basis of payroll assignment. • An annual report containing years of service at KPCO and the salaries of professional employees transferred from KPCo to AEP or its subsidiaries filed in conjunction with the annual transfer of employees report. • An annual report of cost allocation factors in use, supplemented upon significant change. • Summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation effect. • An annual report of methods used to update or revise the cost allocation factors in use, supplemented upon significant change.
Use of Existing Reports [Case No. 99-149, Page 12 ¶7]	Where the same information sought in the above noted reports has been filed with the SEC, FERC, or another state regulatory commission, AEP may provide copies of those filings

SUBJECT	REQUIREMENT
	rather than prepare separate reports.

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LOUISIANA RULES AND REQUIREMENTS

SUMMARY

Louisiana's requirements applicable to cost allocations and affiliate transactions are contained in the Affiliate Transaction Conditions that appear in Appendix A to the Louisiana Public Service Commission's (the Commission's) Order No. U-23327, dated September 16, 1999, in the matter of the proposed merger of American Electric Power Company, Inc. (AEP) and Central and South West Corporation.

DOCUMENTATION REQUIREMENTS

The Commission's documentation requirements applicable to affiliate transactions, as contained in the Affiliate Transaction Conditions, are captured in the following table:

SUBJECT	***REQUIREMENT***
Access to Books and Records	AEP and Southwestern Electric Power Company (SWEPCO, and the Company) will provide the Commission access to their books and records, and to any records of their subsidiaries and affiliates that reasonably relate to regulatory concerns and that affect SWEPCO's cost of service and/or revenue requirement. [¶ 2]
Service Company Costs	For ratemaking and regulatory reporting purposes, SWEPCO shall reflect the costs assigned or allocated from affiliate service companies on the same basis as if SWEPCO had incurred the costs directly. This condition shall not apply to book

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	accounting for affiliate transactions. [¶ 11]

ALLOCATION OF COSTS

The Commission's requirements for the allocation of certain costs and revenues, as contained in the Affiliate Transaction Conditions, are presented in the following table:

SUBJECT	***REQUIREMENT***
Notification of Changes in Cost Allocation Methodologies	The Company shall submit in writing to the Commission any changes it proposes to the System Agreement, the System Integration Agreement and any other affiliate cost allocation agreements or methodologies that affect the allocation or assignment of costs to SWEPCO. The written submission to the Commission shall include a description of the changes, the reasons for such changes, and an estimate of the impact, on an annual basis, of such changes on SWEPCO's regulated costs. To the extent that any such changes are filed with the SEC or FERC, the Company agrees to utilize its best efforts to notify the Commission at least 30 days prior to those filings and at least 90 days prior to the proposed effective date of those changes or as early as reasonably practicable,

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LOUISIANA RULES AND REQUIREMENTS

SUBJECT	***REQUIREMENT***
Notification of Changes in Cost Alloca-tion Method-ologies (Cont'd)	to allow the Commission a timely opportunity to respond to such filings. If the documents to be filed with the SEC or FERC are not finalized 30 days prior to the filing, the information required above may be provided by letter to the Commission with a copy of the SEC or FERC filing to be provided as it is prepared. The filing by the Company of this information with the Commission shall not constitute acceptance of the proposed changes, the allocation or assignment methodologies, or the quantifications for ratemaking purposes. [¶ 12]
Revenue Allocation Applicable to Product or Service Development	If an unregulated business markets a product or service that was developed by SWEPCO or paid for by SWEPCO directly or through an affiliate, and the product or service is actually used by SWEPCO, all profits on the sale of such product or service (based on Louisiana retail jurisdiction) shall be split evenly between SWEPCO, which was responsible for or shared the cost or developing the product, and the unregulated business responsible for

SUBJECT	***REQUIREMENT***
Revenue Allocation Applicable to Product or Service Development (Cont'd)	marketing the product or service to third parties, after deducting all incremental costs associated with making such product or service available for sale, including the direct cost of marketing such product or service. However, in the event that such product or service developed by SWEPCO to be used in its utility business is not actually so used, and subsequently is marketed by the unregulated business to third parties, SWEPCO shall be entitled to recover all of its costs to develop such product or service before any such net profits derived from its marketing shall be so divided. If SWEPCO jointly develops such product or service and shares the development with other entities, then the profits to be so divided shall be SWEPCO's *pro rata* share of such net profits based on SWEPCO's contribution to the development costs. [¶ 14]

TRANSFER PRICING

The Commission's transfer pricing requirements for affiliate transactions, as contained in the Affiliate Transaction Conditions, are presented in the following

table:

SUBJECT	***REQUIREMENT***
Asset Transfers	**Purchases.** Assets with a net book value in excess of $1 million per transaction, purchased by or transferred to the regulated electric utility (SWEPCO) from an unregulated affiliate either directly or indirectly (through another affiliate), must be valued for purposes of the Louisiana retail rate base (but not necessarily for book accounting purposes) at the lesser of the cost to the originating entity and the affiliated group (CSW or AEP) or the fair market value, unless otherwise authorized by applicable Commission rules, orders, or other Commission requirements. [¶ 4.a.] **Sales.** Assets with a net book value in excess of $1 million per transaction, sold by or transferred from the regulated electric utility (SWEPCO) to an unregulated affiliate either directly or indirectly (through another affiliate), with the exception of accounts receivable sold by SWEPCO to AEP Credit Inc., must be valued for purposes of the

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SUBJECT	***REQUIREMENT***
Asset Transfers (Cont'd)	Louisiana retail rate base (but not necessarily for book accounting purposes) at the greater of the cost to SWEPCO or the fair market value, unless otherwise authorized by applicable Commission rules, Orders, or other Commission requirements. [¶ 4.b.] **Reporting.** The Company shall notify the Commission in writing at least 90 days in advance of a proposed purchase, sale or transfer of assets with a net book value in excess of $1 million if such proposed purchase, sale or transfer is expected at least 90 days before the anticipated effective date of the transaction. With the notice, the Company shall provide such information as may be necessary to enable the Commission Staff to review the proposed transaction, including, without limitation, the identity of the asset to be transferred, the proposed transferor and transferee, the value at which the asset will be transferred, the net book value of the asset, and the anticipated effect on Louisiana retail customers.

SUBJECT	***REQUIREMENT***
Asset Transfers (Cont'd)	When such a transaction requires approval of a federal agency, under no circumstances shall such notification be less than 60 days in advance or such longer advance period as the applicable federal agency from time to time prescribe. If not provided with the initial notice, the Company will provide the Commission with a copy of its federal filing at the same time it is submitted to the federal agency. [¶ 6] **Burden of proof.** Consistent with Commission and legal precedents and Commission General Orders, the Company shall have the burden of proof in any subsequent ratemaking proceeding to demonstrate that such purchase, sale or transfer of assets satisfies the requirements of applicable Commission and legal precedent and Commission General Orders, and will not harm the ratepayers. [¶ 7] **Treatment of gains or losses.** The Commission reserves the right, in accordance with Commission and legal precedents and Commission

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SUBJECT	***REQUIREMENT***
Asset Transfers (Cont'd)	General orders, to determine the ratemaking treatment of any gains or losses from the sale or transfer of assets to affiliates. [¶ 8]
Goods and Services	**Purchases.** With the exception of transactions between SWEPCO and AEP Credit Inc. and AEPSC, for goods and services, including lease costs, purchased by SWEPCO from unregulated affiliates either directly or indirectly (through another affiliate), SWEPCO agrees that it will reflect the lower of cost or fair market value in operating expenses for ratemaking purposes, unless otherwise authorized by applicable Commission rules, Orders, or other Commission requirements. [¶ 10] **Sales.** For goods and services, including lease costs, sold by SWEPCO to unregulated affiliates either directly or indirectly (through another affiliate), SWEPCO agrees that it will reflect the higher of cost or fair value in operating income (or as an offset to operating expenses) for ratemaking purposes, unless otherwise authorized by applicable Commission rules,

SUBJECT	REQUIREMENT
Goods and Services (Cont'd)	Orders, or other Commission requirements (e.g., Commission-approved tariffed rates). [¶ 9]

REPORTING REQUIREMENTS

The Commission has not established periodic reporting requirements relative to affiliate transactions other than those noted above in connection with the notification of changes in cost allocation methodologies and asset transfers.

AUDIT REQUIREMENTS

The Commission's audit requirements applicable to affiliate transactions, as contained in the Affiliate Transaction Conditions, are captured in the following table:

SUJECT	REQUIREMENT
Audits of Affiliate Transactions	AEP will cooperate with audits ordered by the Commission of affiliate transactions between SWEPCO and other AEP affiliates, including timely access to the books and records and to persons knowledgeable regarding affiliate transactions, and will authorize and utilize its best efforts to obtain cooperation from its external

SUBJECT	REQUIREMENT
Audits of Affiliate Transactions (Cont'd)	Auditor to make available the audit workpapers covering areas that affect the costs and pricing of affiliate transactions. [¶ 3]

OTHER REQUIREMENTS

Other requirements of the Commission applicable to affiliate transactions, as contained in the Affiliate Transaction Conditions, are presented in the following table:

SUBJECT	REQUIREMENT
Competitive Bidding	SWEPCO or AEPSC on behalf of SWEPCO may not make any non-emergency procurement in excess of $1 million per transaction from an unregulated affiliate other than from AEPSC except through a competitive bidding process or as otherwise authorized by the Commission. Transactions involving the Company and CSW Credit, Inc. (or its successor) for the financing of accounts receivables are exempt from this condition. Records of all such affiliate trans-actions must be maintained until the Company's next comprehensive retail rate review. In addition, at the time of the next comprehen-sive rate review, all such transactions that were not

SUBJECT	***REQUIREMENT***
Competitive Bidding Cont'd)	competitively bid shall be separately identified for the Commission by the Company. This identification shall include all transactions between the Company and AEPSC in which AEPSC acquired the goods or services from another unregulated affiliate. [¶ 13]
Mandating of Retail Access by the Commission	If retail access for SWEPCO-La. is mandated by the Commission, or through action by the Federal Energy Regulatory Commission or federal legislation, then SWEPCO-La. shall have the right to petition the Commission for modification to the terms of this merger settlement, including the affiliate transaction conditions, that are made necessary by the mandating of retail access and its likely impact on the retail rates at SWEPCO-La. Any such petition must establish the necessity of the proposed modifications and provide appropriate protections to ensure that the benefits of this merger are preserved for SWEPCO-La. regulated customers, including merger savings and the hold harmless provisions set forth herein. The Commission will act upon the

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SUBJECT	***REQUIREMENT***
Mandating of Retail Access by the Commission (Cont'd)	petition in accordance with its normal rules and procedures. This paragraph is not intended to limit SWEPCO's right to petition the Commission in the event that electric utility unbundling or retail access is ordered by a state commission regulating SWEPCO's retail rates, provided that SWEPCO must comply with the requirements set forth above in any such petition. [¶ 17]

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SUMMARY

Michigan's rules and requirements applicable to cost allocations and affiliate transactions are included in various orders of the Michigan Public Service Commission (the MPSC, or the Commission).

DOCUMENTATION REQUIREMENTS

The MPSC's documentation requirements for affiliate transactions and cost allocations can be found in the Settlement Agreement approved by the Commission in its Opinion and Order in Case No. U-12204 in the matter of the proposed merger of American Electric Power Company, Inc. and Central and South West Corporation, and its Code of Conduct for electric utilities and alternative electric suppliers (Opinion and Order, dated December 4, 2000, in Case No.U-12134) with Redline changes to October 29, 2001 Final Version. The term "alternative electric suppliers" is defined in MCL 460.10.g, MSA 22.13(10g).

The documentation requirements found in the Settlement Agreement document are captured in the following table:

SUBJECT	***REQUIREMENT***
Separate Books and Records	Each AEP Operating Company shall maintain, in accordance with generally accepted accounting principles, books, records and accounts that are separate from the books, records and accounts of its affiliates, consistent with Part 101 – Uniform System of Accounts prescribed for Public Utilities and

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SUBJECT	***REQUIREMENT***
	Licensees subject to the provisions of the Federal Power Act, [Section 8.B.]
Cost Allocation Documentation	An AEP operating company which provides both regulated and non-regulated services or products, or an affiliate which provides services or products to an AEP operating company, shall maintain documentation in the form of written agreements, an organization chart of AEP (depicting all affiliates and AEP operating companies), accounting bulletins, procedure and work order manuals, or other related documents, which describe how costs are allocated between regulated and non-regulated services or products. [Section 8.P.]
Employee Movements	AEP shall document all employee movement between and among all affiliates. Such information shall be made available to the Commission upon request. [Section 8.G.]
Itemized Billing Statements	Any untariffed, non-utility service provided by an AEP operating company or affiliate service company to any affiliate shall be

SUBJECT	***REQUIREMENT***
Itemized Billing Statements (cont'd)	itemized in a billing statement pursuant to written contract or written arrangement. The AEP operating company and any affiliated service company shall maintain and keep available for inspection by the Commission copies of each billing statement, contract and arrangement between the AEP operating company or affiliated service company and its affiliates that relate to the provision of such untariffed non-utility services. [Section 8.E.] Goods and services provided by a non-utility affiliate to an AEP operating company shall be by itemized billing statement pursuant to a written contract or written arrangement. The operating company and non-utility affiliate shall maintain and keep available for inspection by the Commission copies of each billing statement, contract and arrangement between the operating company and its non-utility affiliates that relate to the provision of such goods and services in accordance with applicable

SUBJECT	REQUIREMENT
	Commission retention requirements. [Section 8.F.]

TRANSFER PRICING

The MPSC's transfer pricing requirements can be found in the Settlement Agreement document, it's Code of Conduct for electric utilities and alternative electric suppliers, and the Company's Code of Conduct compliance plan on file with the Commission.

SETTLEMENT AGREEMENT

The transfer pricing and related requirements contained in the Settlement Agreement document are captured in the following table:

SUBJECT	REQUIREMENT
Guiding Principles	The financial policies and guidelines for transactions between the regulated utility and its affiliates shall reflect the following principles: 1. An AEP operating company's retail customers shall not subsidize the activities of the operating company's non-utility affiliates or its utility affiliates. [Section 8.A.1.] 2. An AEP operating company's costs for jurisdictional rate purposes shall reflect

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SUBJECT	***REQUIREMENT***
Guiding Principles (Cont'd)	only those costs attributable to its jurisdictional customers. [Section 8.A.2.] 3. An objective of these principles shall be to avoid costs found to be just and reasonable for ratemaking purposes by the Commission being left unallocated or stranded between various regulatory jurisdictions, resulting in the failure of the opportunity for timely recovery of such costs by the operating company and/or its utility affiliates; provided, however, that no more than one hundred percent of such costs shall be allocated on an aggregate basis to the various regulatory jurisdictions. [8.A.3.] 4. An AEP operating company shall maintain and utilize accounting systems and records that identify and appropriately allocate

SUBJECT	REQUIREMENT
	costs between the operating company and its affiliates, consistent with these cross-subsidization principles and such financial policies and guidelines. [Section 8.A.4.]

Code of Conduct

The MPSC's Code of Conduct rules as set forth in MICH. ADMIN. CODE R 460.10102 *et. seq.* are captured in the following table:

SUBJECT	REQUIREMENT
R 460.10102 Definitions.	As used in these rules: **(a)** "Affiliate" means a person or entity that directly or indirectly through 1 or more intermediates, controls, is controlled by, or is under common control with another specified entity. As used in these rules, "control" means, whether through an ownership, beneficial, contractual, or equitable interest, the possession, directly or indirectly, of the power to direct or to cause the direction of the management or policies of a person or entity or the ownership of at least 7% of an entity either directly or indirectly. **(b)** "Alternative electric supplier" means a person selling electric generation service to retail customers in this state as licensed by the commission under section 10a of 2016 PA 341, MCL 460.10a. Alternative electric supplier does not include a person who physically delivers electricity directly to retail customers in this state. An alternative electric supplier is not a public utility, but may be an affiliate of a public utility. **(c)** "Commission" means the public service commission. **(d)** "Other entity within the corporate structure" means a division, department, subsidiary, or similar entity within the

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SUBJECT	***REQUIREMENT***
R 460.10102 Definitions. (Cont'd)	corporate structure of a utility. **(e)** "Third-party" means an entity separate from a utility, and separate from a utility affiliate, that offers value-added programs and services to a utility's customers through a contract. **(f)** "Utility" means an electric, steam, or natural gas utility regulated by the public service commission, and an electric or natural gas cooperative that is subject to regulation pursuant to the Electric Cooperative Member-Regulation Act, 2008 PA 167, MCL 460.31to 460.39. **(g)** "Value-added programs and services" means programs and services that are utility or energy related, including, but not limited to, home comfort and protection, appliance service, building energy performance, alternative energy options, or engineering and construction services. Value-added programs and services do not include energy optimization or energy waste reduction programs paid for by utility customers as part of the regulated rates.
MICH. ADMIN. CODE R 460.10103 Preventive measures.	**Rule 3.** **(1)** A utility that offers both regulated and unregulated services shall prevent anticompetitive behavior, cross-subsidization, and preferential treatment prohibited by law and these rules. **(2)** A utility shall not offer unregulated value-added programs and services except through an affiliate or other entity within the corporate structure, or through a third-party contract. **(3)** A utility's regulated services shall not subsidize the business of its affiliates, other entities within the corporate structure, or third-party contractors offering unregulated value-added programs or services.

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SUBJECT	***REQUIREMENT***
MICH. ADMIN. CODE R 460.10104 Records	**Rule 4.** **(1)** A utility shall maintain its books and records separately from those of its affiliates or other entities within the corporate structure offering unregulated value-added programs and services. **(2)** The commission may review records relating to any transaction between a utility and an affiliate, or relating to the offering of unregulated value-added programs and services. At any time, the commission may initiate an investigation into transactions between the utility and its affiliates, or into its offering of value-added programs and services. **(3)** A utility, its affiliates, and other entities within the corporate structure shall keep their books in a manner consistent with generally accepted accounting principles and, where applicable, with the Uniform System of Accounts.
MICH. ADMIN. CODE R 460.10105 Sharing of facilities and employees.	**Rule 5.** **(1)** A utility, its affiliates, and other entities within the corporate structure may share facilities, equipment, operating employees, and computer hardware and software with documented protection to prevent discriminatory access to competitively sensitive information, provided that such sharing complies with section 10ee of 2016 PA 341, MCL 460.10ee, and measures are adopted to prevent cross-subsidization and preferential treatment that is otherwise prohibited. **(2)** A utility may transfer employees between the utility and an affiliate alternative electric supplier providing the utility documents those transfers and files semi-annually with the commission a report of each occasion on which an employee of the utility became an employee of an affiliate alternative electric supplier and/or an employee of an affiliate alternative electric supplier became an employee of the utility. **(3)** None of these rules shall be interpreted to require a utility with fewer than 60

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MICH. ADMIN. CODE R 460.10105 Sharing of facilities and employees (Cont'd)	employees to maintain separate facilities, operations, or personnel used to deliver regulated services and unregulated programs and services. Utilities using a third-party contractor for value-added programs and services remain subject to the provisions of MCL 460.10ee(12).
MICH. ADMIN. CODE R 460.10106 Marketing	**Rule 6.** **(1)** A utility, its affiliates, and other entities within the corporate structure offering unregulated value-added programs or services, shall not engage in joint advertising, marketing, or other promotional activities related to the provision of both regulated and unregulated services, nor shall they jointly sell regulated services and unregulated value-added programs and services. **(2)** A utility or affiliate alternative electric supplier shall not provide or offer to provide any customer with preferential treatment or service for doing business with the utility, its affiliates, or other entities within the corporate structure offering unregulated value-added programs or services, nor shall the utility or affiliate alternative electric supplier provide any customer with inferior treatment or service for doing business with an unaffiliated supplier of a similar service. **(3)** A utility shall not condition or otherwise tie the provision of a utility service or the availability of discounts, rates, other charges, fees, rebates, or waivers of terms and conditions to the taking of any goods or services from the utility, its affiliates, or other entities within the corporate structure offering unregulated value-added programs or services.
MICH. ADMIN. CODE R 460.10107 Utility and affiliate or alternative	**Rule 7.** **(1)** A utility shall not interfere in the business operations of any alternative electric supplier. This provision includes, but is not limited to, all of the following: **(a)** A utility shall not give the appearance that it speaks on behalf of any alternative

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electric supplier relationship	electric supplier or affiliate. **(b)** A utility shall not interfere in the contractual relationship between the alternative electric supplier and its customers unless the utility's action is clearly permitted in the contract between the customer and the alternative electric supplier or in tariffs approved by the commission. **(2)** A utility shall not finance or co-sign loans, provide loan guarantees, provide collateral, or be encumbered or allow its assets to be encumbered by affiliates or other entities within the corporate structure. The utility and its assets shall not be the subject of recourse in the event of default by an affiliate or other entity within the corporate structure.
MICH. ADMIN. CODE R 460.10108 Discrimination	**Rule 8.** **(1)** A utility shall not discriminate in favor of or against any person, including its affiliates. **(2)** A utility shall not provide any affiliate or other entity within the corporate structure offering unregulated value-added programs or services, or any customer of an affiliate or other entity within the corporate structure offering unregulated value-added programs or services, preferential treatment or any other advantages that are not offered under the same terms and conditions and contemporaneously to other suppliers offering programs or services within the same service territory or to customers of those suppliers. **(3)** If a utility provides to any affiliate alternative electric supplier or customers of an affiliate alternative electric supplier a discount, rebate, fee waiver, or waiver of its regulated tariffed terms and conditions for services or products, it shall contemporaneously offer the same discount, rebate, fee waiver, or waiver to all alternative electric suppliers operating within the utility's service territory or all alternative electric suppliers' customers. **(4)** If a utility provides services or products

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MICH. ADMIN. CODE R 460.10108 Discrimination (Cont'd)	to any affiliate or other entity within the corporate structure, and the cost of the service or product is not governed by section 10ee(8) of 2016 PA 341, MCL 460.10ee(8), compensation is based upon the higher of fully allocated embedded cost or fair market price. If an affiliate or other entity within the corporate structure provides services or products to a utility, and the cost of the service or product is not governed by section 10ee(8) of 2016 PA 341, MCL 460.10ee(8), compensation is at the lower of market price or 10% over fully allocated embedded cost. Asset transfers from a utility to an affiliate or other entity within the corporate structure for which the cost is not governed by section 10ee(8) of 2016 PA 341, MCL 460.10ee(8), is at the higher of cost or fair market value. Asset transfers from an affiliate or other entity within the corporate structure to a utility for which the cost is not governed by section 10ee(8) of 2016 PA 341, MCL 460.10ee(8) is at the lower of cost or fair market value.
MICH. ADMIN. CODE R 460.10109 Disclosure of information	**Rule 9.** **(1)** Notwithstanding any provision of this rule, utilities shall comply at all times with applicable data privacy tariffs. **(2)** Prior written approval of the customer is not required for the disclosure of a customer list to a program or service provider of an unregulated value-added program or service in compliance with section 10ee(10)(a) of 2016 PA 341, MCL 460.10ee(10)(a), or to otherwise comply with these rules. A customer list may include only the name and address of a customer. **(3)** Information obtained by a utility in the course of conducting its regulated business shall not be shared directly or indirectly with its affiliates or other entities within the corporate structure offering unregulated value-added programs or services unless that same information is provided upon request to competitors operating in the

SUBJECT	*REQUIREMENT*
MICH. ADMIN. CODE R 460.10109 Disclosure of information (Cont'd)	service territory on the same terms and conditions and contemporaneously. **(4)** Customer specific consumption or billing data shall not be provided to any affiliate, other entity within the corporate structure offering unregulated value-added programs or services, or alternative electric supplier without prior written approval of the customer. **(5)** If a utility provides non-customer specific, or aggregated, customer information to its affiliate or other entity within the corporate structure offering unregulated value-added programs or services, it must, upon request, offer the same information on the same terms and conditions, in the same form and manner, and contemporaneously, to all competitors of that affiliate or other entity within the corporate structure. The provision of such data must comply with all applicable data privacy tariffs. **(6)** When disclosure required in subrule (5) of this rule is otherwise allowed, a utility shall not provide its affiliates or other entities within the corporate structure offering unregulated value-added programs or services with information about the distribution system, including operation and expansion, without providing, upon request, the same information under the same terms and conditions, in the same form and manner, and contemporaneously, to all licensed alternative electric suppliers and competitors of the affiliate or other entity within the corporate structure. The utility shall keep a record of requests for such information, and shall make that record available to the commission upon request. **(7)** A utility shall not provide any information received from or as a result of doing business with a competitor to the utility's affiliate or other entity within the corporate structure offering unregulated value-added programs or services without the written approval of the competitor.

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MICH. ADMIN. CODE R 460.10110 Notification	**Rule 10.** **(1)** Utilities that intend to offer a value-added program or service shall notify the commission not less than 30 days before offering the new program or service. The written notification shall, at a minimum, provide all of the following: **(a)** A detailed description of the new value-added program or service and what it will offer. **(b)** A list of the personnel responsible for management of the value-added program or service and their location within the utility, both physically and within the corporate structure. **(c)** A detailed description of how costs, including but not limited to, billing, postage, and call center costs, will be allocated to the value-added program or service to ensure that there is no cross-subsidization between regulated and unregulated programs or services. **(d)** A copy of the business plan for the value-added program or service. **(e)** Pro forma financial statements that outline the expected financial performance for each value-added program or service for the next 12 months. **(2)** Utilities shall request a docket for the filing of the notification, and shall thereafter make all annual report filings in that docket. **(3)** A utility that intends to sell or transfer an asset with a market value of $ 1,000,000 or more to any affiliate or other entity within the corporate structure shall notify the commission of the impending sale or transfer no less than 30 days before the sale or transfer. An affiliate or other entity within the corporate structure of a utility that intends to sell or transfer an asset with a market value of $ 1,000,000 or more to a utility shall notify the commission of the impending sale or transfer no less than 30 days before the sale or transfer. Upon request, the utility, affiliate, or other entity within the corporate structure shall make available to the commission information

SUBJECT	*REQUIREMENT*
MICH. ADMIN. CODE R 460.10110 Notification (Cont'd)	that demonstrates how the sale or transfer price was determined. Notification shall be in the form of a letter to the director of the regulated energy division of the commission.
MICH. ADMIN. CODE R 460.10111 Oversight	**Rule 11.** **(1)** A utility, its affiliates, and other entities within the corporate structure offering unregulated value-added programs or services shall maintain documentation needed to investigate compliance with section 10ee of 2016 PA 341, MCL 460.10ee, and these rules. All documentation shall be kept at a designated company office in this state, unless the Commission by order has authorized a different location. The utility, its affiliates, and other entities within the corporate structure offering unregulated value-added programs or services shall make this information available for review upon request by the commission or its staff. **(2)** The utility, its affiliates, and other entities within the corporate structure offering unregulated value-added programs or services shall use a documented dispute resolution process separate from any process that might be available from the commission. This dispute resolution process shall address complaints arising from application of these rules. The utility, its affiliates, and other entities within the corporate structure offering unregulated value-added programs or services shall keep a log of all complaints, including the name of the person or entity filing the complaint, the date the complaint was filed, a written statement of the nature of the complaint, and the results of the resolution process. **(3)** A utility, its affiliates, and other entities within the corporate structure offering unregulated value-added programs or services may request a waiver from 1 or more provisions of these rules by filing an

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MICH. ADMIN. CODE R 460.10111 Oversight (Cont'd)	application with the commission. The requesting party carries the burden of demonstrating that such a waiver will not impair the development or functioning of the competitive market. Waivers shall be granted for entities that qualify for loans to deploy broadband services in rural areas under the Rural Electrification Act of 1936, as amended, 7 U.S.C. § 901 et seq.
MICH. ADMIN. CODE R 460.10112 Reporting	**Rule 12.** **(1)** Utilities shall file the code of conduct annual report information required under section 10ee(6)(c) and (15), 2016 PA 341, MCL 460.10ee, no later than April 30 of each year in the docket in which the utility filed its notification for a new program or service, or in a new docket for an existing program or service. Code of conduct annual reports shall include all of the following: **(a)** Designation of a corporate officer of the utility who will oversee compliance with these rules and be available to serve as the commission's primary contact regarding compliance. **(b)** An organizational chart of the parent or holding company showing all regulated entities and affiliates and a description of all programs and services provided between the regulated entity and its affiliates. **(c)** An overview of the report year, including a detailed accounting of how costs were apportioned between the utility and the value-added program or service, expectations for the following year, and any 5-year projections available for each value-added program and service. **(d)** A table illustrating the customer count, revenue, and expense of each value-added program and service. **(e)** A balance sheet, where available, and income statement for each value-added program and service offered by an affiliate or other entity within the corporate structure, including revenues, less direct and indirect expenses broken out separately. Direct and indirect revenues and

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MICH. ADMIN. CODE R 460.10112 Reporting (Cont'd)	expenses shall be separated by category and then aggregated at the direct and indirect levels, and the report shall include gross income, amounts flowed back to ratepayers to reduce rates, and net income. Each category of indirect cost should be accompanied by formulas/calculations/allocations showing how they have been derived. **(f)** General ledger and trial balance for each value-added program and service shall be provided to the commission staff separately on a USB thumb drive or other appropriate technological device with formulas intact. **(g)** The number and type of complaints received in the prior calendar year regarding code of conduct issues from customers, alternative electric suppliers, or any other person or entity, and a summary of the resolution of any complaint that occurred during the calendar year. **(h)** The number of times during the prior calendar year that customer information was provided to an affiliate or competing provider of an unregulated value-added program or service, the identity of the affiliate or competing provider, and a description of the information shared. **(i)** A description of the nature of each transaction with an affiliate or other entity within the corporate structure and of the basis for the cost allocation and pricing established in each transaction. **(j)** Reports of internal audits conducted by the utility regarding transactions between the utility and its affiliates, or transactions between the utility and other entities within the corporate structure offering value-added programs or services. **(2)** The annual report shall be signed by the designated corporate officer or a person responsible for each value-added program and service attesting to the accuracy of the information in the annual report and certifying that there is no cross-subsidization between regulated and non-regulated utility programs and services. **(3)** Copies of federal income tax returns for

SUBJECT	REQUIREMENT
	utilities, affiliates, and, where applicable, other entities within the corporate structure who offer a value-added program or service, shall be available to the commission for inspection and review.

AUDIT REQUIREMENTS

The independent audit requirement regarding the merger has expired. I&M/AEP was required to conduct biennial audits for 8 years after the merger. The final audit was submitted to the Michigan Public Service Commission on December 29, 2008.

OTHER REQUIREMENTS

The MPSC's Code of Conduct (MICH. ADMIN. CODE R 460.10103) provides a utility's regulated services shall not subsidize the business of its affiliates, other entities within the corporate structure, or third-party contractors offering unregulated value-added programs or services. AEP's cost allocation policies and procedures are consistent with Michigan's requirements relative to cross-subsidization.

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SUMMARY

Ohio's requirements applicable to cost allocations and affiliate transactions are, for the most part, captured in the corporate separation rules adopted by the Public Utilities Commission of Ohio (the PUCO, or the Commission) in Ohio Admin. Code Chapter 4901:1-37, and in the regulations and orders of the PUCO.

CAM REQUIREMENTS

The following table details the Commission's Cost Allocation Manual (CAM) requirements:

SUBJECT	***REQUIREMENT***
Summary	Each electric utility that receives products and/or services from an affiliate and/or that provides products and/or services to an affiliate shall maintain information in the CAM, documenting how costs are allocated between the electric utility and affiliates and the regulated and nonregulated operations. [Source: 4901:1-37-08(A)]
Maintenance	The CAM will be maintained by the electric utility. [Source: 4901:1-37-08(B)]
Assurances	The CAM is intended to ensure the commission that no cross-subsidization is occurring between the electric utility and its affiliates. [Source: 4901:1-37-08(C)]
Contents	The CAM will include: (1) An organization chart of the holding company, depicting all affiliates,

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SUBJECT	***REQUIREMENT***
Contents (Cont'd)	as well as a description of activities in which the affiliates are involved. (2) A description of all assets, services, and products provided to and from the electric utility and its affiliates. (3) All documentation including written agreements, accounting bulletins, procedures, work order manuals, or related documents, which govern how costs are allocated between affiliates. (4) A copy of the job description of each shared employee. (5) A list of names and job summaries for shared consultants and shared independent contractors. (6) A copy of all transferred employees' (from the electric utility to an affiliate or vice versa) previous and new job description. (7) A log detailing each instance in which the electric utility exercised discretion in the application of its tariff provisions. (8) A log of all complaints

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SUBJECT	***REQUIREMENT***
Contents (Cont'd)	brought to the utility regarding this chapter. (9) A copy of the minutes of each board of directors meeting, that will be maintained for a minimum of three years.
Method for Charging Costs	The method for charging costs and transferring assets shall be based on fully allocated costs. [Source: 4901:1-37-08 (E)]
Audit Trail	The costs shall be traceable to the books of the applicable corporate entity. [Source: 4901:1-37-08(F)]
Record Retention Requirements	The electric utility and affiliates shall maintain all underlying affiliate transaction information for a minimum of three years. [Source: 4901:1-37-08 (G)]
Summary of Changes	Following approval of a corporate separation plan, an electric utility shall provide the director of the rates and analysis department (or their designee) with a summary of any changes in the CAM at least every twelve months. [Source: 4901:1-37-08 (H)]
Company Contact	The compliance officer designated by the electric utility will act as the contact for the staff when staff seeks data regarding affiliate transactions, personnel transfers, and the

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SUBJECT	***REQUIREMENT***
	sharing of employees. [Source: 4901: 1-37-08 (I)]
Commission Inspection	The staff may perform an audit of the CAM in order to ensure compliance with this rule.[Source: 4901:1-37-08(J)]

TRANSFER PRICING

The Commission's corporate separation rule, as expressed in the CAM requirements themselves (see above), provides that "the method for charging costs and transferring assets shall be based on fully allocated costs." [Source: 4901:1-37-08 (E)]

REBUTTABLE PRESUMPTION

Transactions made in accordance with rules, regulations, or service agreements approved by the Federal Energy Regulatory Commission, Securities and Exchange Commission, and the Commission, which rules the electric utility shall maintain in its cost allocations manual (CAM) and file with the Commission, provide a rebuttable presumption of compliance with the costing principles contained in this chapter. [Source: 4901:1-37-04 (A) (6)]

REPORTING REQUIREMENTS

The Commission's corporate separation rule, as expressed in the CAM requirements themselves (see above), provides that "*an electric utility shall provide the director of the rates and analysis department (or their designee) with a summary of any changes in the CAM at least every twelve months.*"

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AUDITS	The staff may perform an audit of the CAM in order to ensure compliance with this rule.

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OKLAHOMA RULES AND REGULATIONS

SUMMARY

Oklahoma's requirements applicable to affiliate transactions are focused on the Oklahoma Corporation Commission's (the Commission's or the OCC's) ability to access the books and records of Public Service Corporation of Oklahoma (PSO) and its AEP affiliates as stated in the Stipulation approved by the OCC in Cause No. PUD 980000444, dated April 16, 1999. Other requirements are contained in orders issued by the OCC.

ACCESS TO BOOKS AND RECORDS

Section 5 of the Stipulation in Cause No. 980000444 concerning the proposed merger of American Electric Power Company, Inc. and Central and South West Corporation addresses the issue of access to books and records as captured in the following table:

SUBJECT	***REQUIREMENT***
Access to Books and Records of AEP and Its Affiliates	Subject to regulatory authority, the OCC and Attorney General will either have access in Oklahoma to copies of books and records of AEP and its affiliates and subsidiaries (including their participation in joint ventures) with respect to matters and activities that relate to Oklahoma retail rates or AEP will pay reasonable and prudently incurred travel expenses to conduct on-site review of the books and records.
Access to Books and Records of PSO	The OCC and Attorney General will have access to the books and records of PSO to the degree required to fully audit, examine, or otherwise

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	investigate transactions between PSO and AEP affiliates.

STANDARDS FOR TRANSACTIONS BETWEEN UTILITIES AND AFFILIATE(S)

The Oklahoma's rules and requirements applicable to Affiliate Transactions are contained in the Oklahoma Corporation Commission's (OCC) Electric Utility Rules adopted May 2, 2005, and effective July 1, 2005.

The applicable rules and requirements are captured in the following table:

SUBJECT	REQUIREMENTS
Transactions with Affiliates	(1) Electric utilities must apply any tariff provision in the same manner to the same or similarly situated persons if there is discretion in the application of the provision. (2) Electric utilities must strictly enforce a tariff provision for which there is no discretion in the application of the provision. (3) Except as necessary for physical operational reasons, electric utilities may not, through a tariff provision or otherwise, give their affiliates or knowingly give customers of their affiliates preference over other utility customers in matters relating to any service offered including, but not limited to: generation, transmission, distribution and ancillary services, scheduling, balancing, or curtailment

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SUBJECT	REQUIREMENTS
Transactions with Affiliates (Cont'd)	policy. (4) Unless such disclosure is made public simultaneously or as near to the event as possible, electric utilities shall not disclose to their affiliates any information which they receive from, a non-affiliated customer, a potential customer, any agent of such customer, or potential customer, or other entity seeking to supply electricity to a customer or potential customer. (5) An electric utility's operating employees and the operating employees of its affiliate must function independently of each other and shall be employed by separate corporate entities. (6) Electric utilities and their affiliates shall keep separate books and records. (7) Electric utilities shall establish a complaint procedure. In the event of the electric utility and the complainant are unable to resolve a complaint, the complainant may address the complaint to the Commission. (8) With respect to any transaction or agreement relating in any way to electric generation, transmission, distribution and ancillary services, an electric utility

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SUBJECT	REQUIREMENTS
Transactions with Affiliates (Cont'd)	shall conduct all such transactions with any of its affiliates on an arm's length basis. (9) The Commission shall resolve affiliate transactions disputes or abuses on a case-by-case basis. Any aggrieved party may file a complaint with the Commission alleging the particulars giving rise to the alleged dispute or abuse. (10) Electric utilities must process all similar requests for electric services in the same manner and within the same period of time. (11) Electric utilities shall not provide leads to their affiliates and shall refrain from giving any appearance that the electric utility speaks on behalf of its affiliate(s). Nor shall the affiliate trade upon, promote or advertise its affiliation or suggest that it receives preferential treatment as a result of its affiliation. The use of a common corporate or parent holding company name shall not be a violation of this provision so long as the regulated utility and the affiliate entities can be distinguished. (12) Electric utilities, except for billing and collection services and customer service, or by order of the Commission,

SUBJECT	REQUIREMENTS
Transactions with Affiliates (Cont'd)	shall not share their customer list or related customer information with affiliates unless the information is simultaneously shared with non-affiliate entities. (13) The electric utility shall not communicate with any third party that any advantage in the provision of electric services may accrue to such third party as a result of that third party's dealings with the electric utility's affiliate. [165:35-31-19]

TRANSFER PRICING AND OTHER TRANSACTION REQUIREMENTS

The OCC's rules contain very specific requirements for transactions between a utility and its affiliates including the pricing of such transactions. The applicable requirements are captured in the following table:

SUBJECT	REQUIREMENTS
Transfer Pricing and Other	• **Transactions between a utility and its affiliates.** A utility shall not subsidize the business activities of any affiliate with revenues from a regulated service. A utility cannot recover more that its reasonable fair share of the fully allocated costs for any transaction or shared services. • **Contemporaneous record requirement.** A utility shall maintain a contemporaneous

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SUBJECT	REQUIREMENTS
Transfer Pricing and Other (Cont'd)	written record of all individual transactions with a value equal to or over one million dollars with its affiliates, excluding those involving shared services or corporate support services and those transactions governed by tariffs or special contracts. Such records, which shall include at a minimum, the date of the transactions, name of affiliate(s) involved, name of a utility employee knowledgeable about the transaction, and a detailed description of the transaction with appropriate support documentation for review purposes, shall be maintained by the utility for three years. • **Transfer of assets.** Except as otherwise required by federal statute or regulation or pursuant to Commission authorized competitive bidding, tariffs, special contract, or as otherwise ordered by the Commission; cost recovery for property transferred from a utility to its affiliate shall be priced at the "higher of cost or fair market value." Except as otherwise required

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SUBJECT	REQUIREMENTS
Transfer Pricing and Other (Cont'd)	by federal statute or regulation, or pursuant to Commission authorized competitive bidding, tariffs, special contract or as otherwise ordered by the Commission; asset valuation and transfers of property transferred from an affiliate to its utility shall be priced at the "lower of cost or fair market value." No matter the origin of the transaction, all transfers between a utility and an affiliate will be individually scrutinized by the Commission on a case-by-case basis. • **Sale of products or services.** Except as otherwise required by federal or state statute or regulation, or pursuant to Commission authorized competitive bidding, tariffs, special contract or as otherwise ordered by the Commission; any sale of products and services provided from the affiliate to the utility shall be priced at the "lower of cost or fair market value." Except as otherwise required by federal statute or regulation, or pursuant to

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SUBJECT	REQUIREMENTS
Transfer Pricing and Other (Cont'd)	Commission authorized competitive bidding, tariffs, special contract or as otherwise ordered by the Commission; any sale of jurisdictional products and services provided from the utility to the affiliate shall be priced at "higher of cost or fair market value." • **Joint purchases.** A utility may make a joint purchase with its affiliates of goods and services involving goods and/or services necessary for utility operations. The utility must ensure that all joint purchases are priced, reported, and conducted in a manner that permits clear identification of the utility's and the affiliate's allocations of such purchases.

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SUBJECT	REQUIREMENTS
Transfer Pricing and Other (Cont'd)	• **Tying arrangements prohibited.** Unless otherwise allowed by the Commission through a rule, order or tariff, a utility shall not condition the provision of any product, service, pricing benefit, waivers or alternative terms or conditions upon the purchase of any other good or service from the utility's affiliate. [165:35-31-20]
Separate Books and Financial Transactions	A utility shall keep separate books of accounts and records from its affiliates. The Commission may review records relating to any transaction between a utility and an affiliate to ensure compliance with this Subchapter including the records of both the utility and the affiliate relating to any transaction. (1) In accordance with generally accepted accounting principles, a utility shall record all transactions with its affiliates, whether they involve direct or indirect expenses. (2) A utility shall prepare non-GAAP financial statements that are not consolidated with those of its affiliates.

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SUBJECT	REQUIREMENTS
Separate Books and Financial Transactions (Cont'd)	(3) A utility shall have a cost allocation manual or upon Commission request, be able to provide its cost allocation methodology in written form with supporting documentation. Such records shall reflect the transaction and the allocated costs, with supporting documentation, to justify the valuation. • **Limited credit, investment or financing support by a utility.** A utility may share credit, investment, or financing arrangements with its affiliates if it complies with paragraphs (1) and (2) of this Subsection. (1) The utility shall implement adequate safeguards precluding employees of an affiliate from gaining access to information in a manner that would allow or provide a means to transfer confidential information from a utility to an affiliate, create an opportunity for preferential treatment or unfair competitive advantage, lead to customer confusion, or create an opportunity for preferential treatment or

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SUBJECT	REQUIREMENTS
Separate Books and Financial Transactions (Cont'd)	unfair competitive advantage, lead to customer confusion, or create opportunities for subsidization of affiliates. (2) Where an affiliate obtains credit under any arrangement that would include a pledge of any assets in the rate base of the utility or a pledge of cash necessary for utility operations the transactions shall be reviewed by the Commission on a case-by-case basis. • **Cost of financing transactions of any affiliate.** The cost of any financial transactions, in part or in full, or any debt, equity, trading activity, or derivative, of any parent company, holding company or any affiliate, which has a direct or indirect financial or cost impact upon the utility shall be reviewed by the Commission on a case-by-case basis. [165:35-31-21]

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TENNESSEE RULES AND REQUIREMENTS

SUMMARY

Tennessee has no specific rules and requirements applicable to cost allocations and affiliate transactions. In 1999, the Consumer Advocate Division of the Office of the Attorney General made a request for a rulemaking concerning proposed rules for cost allocations and affiliate transactions before the Tennessee Regulatory Authority.

COMMISSION ACTION

The request for rulemaking by the Consumer Advocate Division was placed on the Tennessee Regulatory Authority's docket in 1999 and comments and reply comments were filed by Kingsport Power Company and the Consumer Advocate Division as well as other parties (Docket No. 98-00690).

Any rules or requirements of the Tennessee Regulatory Authority applicable to cost allocations and affiliate transactions will be summarized in this document when and if they are adopted.

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TEXAS RULES AND REQUIREMENTS

SUMMARY

Texas' rules and requirements applicable to affiliate transactions are contained in Public Utility Regulatory Act (PURA) Sections 36.058 and 39.157(d), as well as the Public Utility Commission of Texas (PUCT) rules under Texas Administrative Code (TAC), Title 16, Part II Substantive Rules Chapter 25 – Electric – Rules Applicable to Electric Service Providers.

DOCUMENTATION REQUIREMENTS

The PUCT's documentation requirements for affiliate transactions are contained in its Electric Substantive Rules, as captured in the following table:

SUBJECT	REQUIREMENT
Separate Books and Records	• A utility and its affiliates shall keep separate books of accounts and records, and the Commission may review records relating to transactions between a utility and an affiliate. • In accordance with generally accepted accounting principles or state and federal guidelines, as appropriate, a utility shall record all transactions with its affiliates, whether they involve direct or indirect expenses.

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	• A utility shall prepare financial statements that are not consolidated with those of its affiliates. [§25.272(d)(6)(A)-(B)]

TRANSFER PRICING AND OTHER TRANSACTION REQUIREMENTS

The PUCT's substantive rules contain very specific requirements for transactions between a utility and its affiliates, including the pricing of such transactions. The applicable requirements are captured in the following table:

SUBJECT	REQUIREMENT
Transactions with All Affiliates	• **General.** A utility shall not subsidize the business activities of any affiliate with revenues from a regulated service. In accordance with PURA and the Commission's rules, a utility and its affiliates shall fully allocate costs for any shared services, including corporate support services, offices, employees, property, equipment, computer systems, information systems, and any other shared assets, services, or products. [§25.272(e)(1)] • **Sale of products or services by a utility.** Unless otherwise approved

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Transactions with All Affiliates (Cont'd)	by the Commission and except for corporate support services, any sale of a product or service by a utility shall be governed by a tariff approved by the Commission. Products and services shall be made available to any third party entity on the same terms and conditions as the utility makes those products and services available to its affiliates. [§25.272(e)(1)(A)] • **Purchase of products, services, or assets by a utility from its affiliate.** Products, services, and assets shall be priced at levels that are fair and reasonable to the customers of the utility and that reflect the market value of the product, service, or asset. [§25.272(e)(1)(B)] • **Transfers of assets.** Except for asset transfers implementing unbundling pursuant to PURA §39.051, asset valuation in accordance

SUBJECT	REQUIREMENT
Transactions with All Affiliates (Cont'd)	with PURA §39.262, and transfers of property pursuant to a financing order issued under PURA, Chapter 39, Subchapter G, assets transferred from a utility to its affiliates shall be priced at levels that are fair and reasonable to the customers of the utility and that reflect the market value of the assets or the utility's fully allocated cost to provide those assets. [§25.272(e)(1)(C)] • **Transfer of assets implementing restructuring legislation.** The transfer from a utility to an affiliate of assets implementing unbundling pursuant to PURA §39.051, asset valuation in accordance with PURA §39.262, and transfers of property pursuant to a financing order issued under PURA, Chapter 39, Subchapter G will be reviewed by the Commission pursuant to the applicable provisions of PURA, and any rules implementing those provisions. [§25.272(e)(1)(D)]

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Transactions with Competitive Affiliates	• **General.** Unless otherwise allowed in this sub-section on transactions between a utility and its affiliates, transactions between a utility and its competitive affiliates shall be at arm's length. A utility shall maintain a contemporaneous written record of all transactions with its competitive affiliates, except those involving corporate support services and those transactions governed by tariffs. Such records, which shall include the date of the transaction, name of the affiliate involved, name of a utility employee knowledgeable about the transaction, and a description of the transaction, shall be maintained by the utility for three years. In addition to the requirements specified above for transactions with all affiliates, the provisions cited in the following bullets apply to transactions between utilities and their competitive affiliates.

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SUBJECT	REQUIREMENT
Transactions with Competitive Affiliates (Cont'd)	[§25.272(e)(2)] • **Provision of corporate support services.** A utility may engage in transactions directly related to the provision of corporate support services with its competitive affiliates. Such provision of corporate support services shall not allow or provide a means for the transfer of confidential information from the utility to the competitive affiliate, create the opportunity for preferential treatment or unfair competitive advantage, lead to customer confusion, or create significant opportunities for cross-subsidization of the competitive affiliate. [§25.272(e)(2)(A)] • **Purchase of products or services by a utility from its competitive affiliate.** Except for corporate support services, a utility may not enter into a transaction to purchase a product or service from a competitive affiliate

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Transactions with Competitive Affiliates (Cont'd)	that has a per unit value of $75,000 or more, or a total value of $1 million or more, unless the transaction is the result of a fair, competitive bidding process formalized in a contract subject to the provisions of §25.273 of this title (relating to Contracts Between Electric Utilities and Their Competitive Affiliates). [§25.272(e)(2)(B)] • **Transfers of assets.** Except for asset transfers facilitating unbundling pursuant to PURA §39.051, asset valuation in accordance with PURA §39.262, and transfers of property pursuant to a financing order issued under PURA, Chapter 39, Subchapter G, any transfer from a utility to its competitive affiliates of assets with a per unit value of $75,000 or more, or a total value of $1 million or more, must be the result of a fair, competitive bidding process formalized in a contract subject to the provisions of §25.273 of

SUBJECT	REQUIREMENT
	this title. [§25.272(e)(2)(C)]

REPORTING REQUIREMENTS

The PUCT's requirements applicable to the reporting of affiliate transactions by electric utilities are contained in its substantive rules, as captured in the following table:

SUBJECT	REQUIUREMENT
Annual Report of Affiliate Transactions	A "Report of Affiliate Activities" shall be filed annually with the Commission. Using forms approved by the Commission, a utility shall report activities among itself and its affiliates. The report shall be filed by June 1, and shall encompass the period from January 1 through December 31 of the preceding year. [§25.84 (d)]
Copies of Contracts or Agreements	A utility shall reduce to writing and file with the Commission copies of any contracts or agreements it has with its affiliates. This requirement is not satisfied by the filing of an earnings report. All contracts or agreements shall be filed by June 1 of each year as attachments to the annual "Report of Affiliate Activities." In subsequent years, if no significant changes have been made to the contract or agreement, an

SUBJECT	REQUIUREMENT
	amendment sheet may be filed in lieu of refiling the entire contract or agreement. [§25.84 (e)]
Tracking Migration of Employees	A utility shall track and document the movement between the utility and its competitive affiliates of all employees engaged in transmission and distribution system operations, including persons employed by a service company affiliated with the utility who are engaged in transmission or distribution system operations on a day-to-day basis or have knowledge of transmission or distribution system operations. Employee migration information shall be included in the utility's annual "Report of Affiliate Activities." The tracking information shall include an identification code for the migrating employee, the respective titles held while employed at each entity, and the effective dates of the migration. [§25.84 (f)]

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REPORTING REQUIREMENTS

Section 25.84(g)(h)(i) of the Commission's Substantive Rules require that informal code of conduct complaints, deviations from the code of conduct and updates to the utility's compliance plan be filed at the PUCT.

AUDIT REQUIREMENTS

The PUCT's audit requirements applicable to affiliate transactions by electric utilities are contained in its substantive rules, as captured in the following table:

SUBJECT	***REQUIREMENT***
General	A utility and its affiliates shall maintain sufficient records to allow for an audit of the transactions between the utility and its affiliates. At any time, the Commission may, at its discretion, require a utility to initiate, at the utility's expense, an audit of transactions between the utility and its affiliates performed by an independent third party. [§25.272 (d)(6)(C)]
Compliance Audits	No later than one year after the utility has unbundled pursuant to PURA §39.051, or acquires a competitive affiliate, and, at a minimum, every third year thereafter, the utility shall have an audit prepared by independent auditors that verifies that the utility is in compliance with this section. For a utility that has no
Compliance	

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SUBJECT	***REQUIREMENT***
Audits (Cont'd)	competitive affiliates, the audit may consist solely of an affidavit stating that the utility has no competitive affiliates. The utility shall file the results of each said audit with the commission within one month of the audit's completion. The cost of the audits shall not be charged to utility ratepayers. [§25.272 (i)(3)]

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VIRGINIA RULES AND REQUIREMENTS

SUMMARY

The Code of Virginia requires approval of contracts between a public service company and any affiliated interests. Virginia's rules and requirements applicable to cost allocations and affiliate transactions can be found in the Code and in the regulations and orders of the Virginia State Corporation Commission (the SCC, or the Commission), particularly the Final Orders in Case Nos. PUA000029 and PUE010013.

SCC APPROVAL

No contract or arrangement providing for the furnishing of management, supervisory, construction, engineering, accounting, legal, financial or similar services, and no contract or arrangement for the purchase, sale, lease or exchange of any property, right or thing, other than those above enumerated, or for the purchase or sale of treasury bonds or treasury capital stock made or entered into between a public service company and any affiliated interest shall be valid or effective unless and until it shall have been filed with and approved by the Commission [Code of VA §56-77].

DOCUMENTATION

The Commission's documentation requirements related to affiliate transactions are captured in the following table:

SUBJECT	***REQUIREMENT***
Separate Books and Records	Each affiliated competitive service provider shall maintain separate books of accounts and records. [20 VAC 5-312-30 C]
Access to Books and Records	The Commission may inspect the books, papers, records and documents of, and require

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VIRGINIA RULES AND REQUIREMENTS

SUBJECT	***REQUIREMENT***
Access to Books and Records (Cont'd)	special reports and statements from, every generation company affiliated with a local distribution company regarding transactions with its local distribution company affiliate. Upon complaint or on its own initiative, the Commission may also (I) investigate alleged violations of this charter, and (ii) seek to resolve any complaints filed with the Commission against any such affiliated generation company. [20 VAC 5-202-30 B 7]
Employee Transfers	An affiliated competitive service provider shall document each occasion that an employee of its affiliated local distribution company, or of the transmission provider that serves its affiliated local distribution company, becomes one of its employees and each occasion that one of its employees becomes an employee of its affiliated local distribution company or the transmission provider that serves its affiliated local distribution company. Upon staff's request, such information shall be filed with the SCC that identifies each such

SUBJECT	REQUIREMENT
Employee Transfers (Cont'd)	occasion. Such information shall include a listing of each employee transferred and a brief description of each associated position and responsibility. [20 VAC 5-312-30 B 3]

TRANSFER PRICING

The SCC's transfer pricing rules applicable to affiliate transactions between the local distribution company (LDC) and certain affiliate are contained in various orders of the Commission.

Rules Applicable to Functional Separation of Incumbent Electric Utilities under the Virginia Restructuring Act(Case No. PUA000029)

The SCC's rules applicable to the functional separation of incumbent electric utilities under the Virginia Electric Utility Restructuring Act contain specific transfer pricing requirements for transactions between the LDC and an affiliated generation company as captured in the following table:

SUBJECT	REQUIREMENT
Sale of Non-Tariffed Services, Facilities and Products	LDCs shall be compensated at the greater of fully distrib-uted cost or market price for all non-tariffed services, facilities, and products provided to an affiliated generation company.
Purchase of Non-Tariffed Services, Facilities and Products	An affiliated generation company shall be compensated at the lower of fully distributed cost or market price for all non-tariffed services, facilities, and products provided to the LDC.

SUBJECT	***REQUIREMENT***
Unavailable Market Prices	If market price data are unavailable for purposes of such calculations, non-tariffed services, facilities and products shall be compensated at fully distrib-uted costs. In such event, the LDC shall document its efforts to determine market price data and its basis for concluding that such price data are unavailable.

[Source: 20 VAC 5-202-30 B 5 a]

Rules Applicable to Retail Access (Case No. PUE010013)

The SCC's rules for retail access contain specific transfer pricing requirements concerning transactions between the local distribution company and its affiliated competitive service providers as captured in the following table:

SUBJECT	***REQUIREMENT***
Sale of Non-Tariffed Services, Facilities and Products	The local distribution company shall be compensated at the greater of fully distributed cost or market price for all non-tariffed services, facilities, and products provided to an affiliated competitive service provider.
Purchase of Non-Tariffed Services, Facilities and Products	An affiliated competitive service provider shall be compensated at the lower of fully distributed cost pr market price for all non-tariffed services, facilities, and products

SUBJECT	REQUIREMENT
	provided to the local distribution company.
Unavailable Market Prices	If market price data are unavailable, non-tariffed services, facilities and products shall be compensated at fully distributed cost and the local distribution company shall document its efforts to determine market price data and its basis for concluding that such price data are unavailable. Notification of a determination of the unavailability of market price data shall be included with the annual report of affiliate transactions that is required to be filed by the local distribution company with the SCC.

[Source: 20 VAC 5-312-30 I. 1.]

AFFILIATE TRANSACTION REPORTING REQUIREMENTS

Virginia's general reporting requirements for affiliate transactions have evolved through several recent affiliate agreement approval orders and are summarized in the following table:

SUBJECT	REQUIREMENT
Annual Report of Affiliate Transactions	An annual report of affiliate transactions shall be filed by May 1 of each year with the SCC's Director of Public

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State Commission Rules

Subject

VIRGINIA RULES AND REQUIREMENTS

SUBJECT	***REQUIREMENT***
	Utility Accounting for transactions for the prior calendar year. The annual report shall include all affiliate agreements/ arrangements regardless of amount involved and shall supersede all previous reporting requirements for affiliate transactions (except, see Statement of Utility Assets Sold, Purchased or Acquired below). The report shall contain the following information: 1. Affiliate's name 2. Description of each affil-iate arrangement/agreement 3. Dates of each affiliate arrangement/agreement 4. Total dollar amount of each affiliate arrangement/agree-ment 5. Component costs of each arrangement/agreement where services are provided to an affiliate (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overhead) 6. Profit component of each arrangement/agreement where

SUBJECT	***REQUIREMENT***
Annual Report of Affiliate Transactions (Cont'd)	services are provided to an affiliate and how such component is determined 7. Comparable market values and documentation related to each arrangement/ agreement 8. Percent/dollar amount of each affiliate arrangement/agreement charged to expense and/or capital accounts, and 9. Allocation bases/factors for allocated costs. Transfers of assets between APCO and AEPC with values of $100,000 or less must be reported in the annual report of affiliated transactions. All transfers of assets between APCO and AEPC with a value exceeding $100,000 require prior Commission approval. *[Source: SCC Order, dated March 4, 1998, in Case No. PUA970035]* The Annual Report of Affiliate Transactions shall also include copies of all executed Greenfield Site Agreements between APCO and AEPC along with a description of the particulars of each site as well as the book value of the underlying land relative to the proposed per site license fee of $10,200/year (less any volume discount for multiple

SUBJECT	***REQUIREMENT***
	sites). *[Source: SCC Order, dated December 6, 199, in Case No. PU990053]*
Annual Report Under the Virginia Electric Utility Restructur-ing Act	Local distribution companies (LDCs) shall file annually, with the Commission, a report that shall, at a minimum, include: (i) the amount and description of each type of non-tariffed service provided to or by an affiliated generation company; (ii) accounts debited or credited; and (iii) the compensation basis used (i.e., market price or fully distributed cost). The LDC shall make available to the Commission's staff, upon request, the following documentation for each agreement and arrangement where services are provided to or by an affiliated generation company: (i) component costs (i.e., direct or indirect labor, fringe benefits, travel or housing, materials, supplies, indirect miscellaneous expenses, equipment or facilities charges, and overhead); (ii) profit component; and (iii) comparable market values and documentation. *[Source: 20 VAC 5=202-30 B 6]*

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SUBJECT	***REQUIREMENT***
Annual Report Required by the Rules Governing Retail Access to Competitive Energy Services	The local distribution company (LDC) shall file annually, with the SCC, a report that shall, at a minimum, include: the amount and description of each type of non-tariffed service provided to or by an affiliated competitive service provider; accounts debited or credited; and the compensation basis used, i.e., market price or fully distributed cost. The LDC shall maintain the following documentation for each agreement and arrangement where such services are provided to or by an affiliated competitive service provider and make such documentation available to staff upon request: (i) component costs (i.e., direct or indirect labor, fringe benefits, travel or housing, materials, supplies, indirect miscellaneous expenses, equipment or facilities charges, and overhead; (ii) profit component; and (iii) comparable market values, with supporting documentation. *[20 VAC 5-312-30 I 2]*
Schedule of Utility Assets Purchased or Sold	APCO must file annually a schedule of purchases from affiliates and sales to affiliates, if any, of utility assets, amounting to less than $25,000 for each such

SUBJECT	***REQUIREMENT***
	transaction, made during the preceding calendar year. *[Source: SCC Order, dated August 29, 1956, in Case No. 13162, and SCC order, dated February 20, 1981, in Case PUA810009]*

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State Commission Rules

Subject

WEST VIRGINIA RULES AND REQUIREMENTS

SUMMARY

The West Virginia Code requires approval of contracts between a public utility and its affiliates. The orders issued by the Public Service Commission of West Virginia (PSC, or Commission) concerning such matters contain requirements related to affiliate transactions.

PSC APPROVAL

Unless the consent and approval of the PSC is obtained, no public utility in West Virginia may, by any means, direct or indirect, enter into any contract or arrangement for management, construction, engineering, supply or financial services or for the furnishing of any other service, property or thing with any affiliated corporation, person or interest *[West Virginia Code § 24-2-12]*. The individual orders issued by the Commission approving such contracts establish requirements applicable to specific transactions with affiliates.

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Section

Introduction

Subject

OVERVIEW (PROCEDURES)

SUMMARY	At AEP, cost allocations between regulated and non-regulated operations take place through intercompany billings and affiliate transactions. The intercompany billing process and related procedures move costs between AEP System's regulated electric utilities and their non-regulated affiliates. The cost allocation process recognizes the nature of the work performed for the respective parties and their use of services and facilities.
TRANSACTIONS	The financial transaction coding process used by AEP is the first step in separating costs between regulated and non-regulated operations.
TIME REPORTING	Labor cost is a large component of the total cost allocated between regulated and non-regulated operations. Time reporting and labor costing procedures are in place to ensure that labor costs are properly allocated and billed to the companies that benefit from the services which are performed.
AEPSC BILLING SYSTEM	AEPSC performs services for American Electric Power Company, Inc., the parent holding company, and most subsidiaries in the AEP System. AEPSC uses a work order system to collect and bill costs to its Afflilate companies for the services that it performs.

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Section

Introduction

Subject

OVERVIEW (PROCEDURES)

INTERCOMPANY BILLING	Other AEP System companies share costs with their affiliates through an intercompany billing process. This process transfers the cost of performing services and conducting projects for affiliates in the AEP System.
INTERUNIT ACCOUNTING	Certain transactions are allocated between companies through inter-unit accounting whereby transactions are recorded in the first instance by the companies for which the transactions have been incurred.
ASSET TRANSFERS	Plant and equipment as well as materials and supplies are transferred among the AEP System companies based on who uses the items. Procedures are in place to properly account for the transfer and sale of those items.

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Transactions

Subject

OVERVIEW

SUMMARY

The process of cost allocation between regulated and non-regulated operations begins with the coding of expenses and other transactions.

RESPONSIBILITY

Transaction coding is the responsibility of the business units that budget for and initiate the transactions.

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CODING BLOCKS

Various coding blocks, also known as chartfields, are used to code financial transactions for accounting and cost allocation purposes.

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Transactions

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CODING

SUMMARY

Proper chartfield coding is mandatory to ensure accurate financial reports and inter-company billings.

CODING RESPONSIBILITY

Chartfield coding is the responsibility of the business units who incur various expenditures, and who report their labor hours. These expenses are initiated and approved by the business units in accordance with their operating plans and financial budgets.

MAINTENANCE OF CHARTFIELD VALUES

The Service Corporation Accounting group is primarily responsible for maintaining chartfield values. The business units request changes to the chartfield values based on their need to track and manage costs, bill affiliated companies and comply with external reporting requirements. This group evaluates all requests in connection with its oversight responsibilities related to internal budgeting, cost allocations, and external reporting. Approved changes are implemented on a timely basis.

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Transactions

Subject

CHARTFIELDS

SUMMARY

AEP's accounting systems use chartfields or coding blocks to classify and accumulate transactions for financial and managerial accounting and reporting. Each chartfield/coding block is used for a specific purpose.

CODING BLOCKS

GENERAL LEDGER CHARTFIELDS:

General Ledger Business Unit	Account Number	Department ID	Product Code	Affiliate Code	Operating Unit Code

PROJECTS CHARTFIELDS:

Project Costing Business Unit	Project ID	Work Order *(Project Activity)*	Cost Component *(Resource Type)*	Activity Code *(Resource Category)*	Tracking Code *(Resource Subcategory)*

General Ledger Business Unit

The **General Ledger Business Unit** identifies the AEP System company or company segment for which the transaction is recorded. Each AEP System Company is assigned a unique code. For example, American Electric Power Company, Inc. is Business Unit 100 and AEP Texas Central-Distribution is Business Unit 211.

Account Number

The **Account Number** records the transaction in the appropriate balance sheet or income statement account using the FERC System of Accounts.

Department ID

The **Department ID** connects the transaction to the responsible organization for reporting and budgeting purposes.

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Transactions

Subject

CHARTFIELDS

Product Code	The **Product Code** describes the product or service supplied. It is primarily used by entries providing services to other AEP groups.
Affiliate Code	The **Affiliate Code** identifies transactions conducted with an affiliate. The **General Ledger Business Unit** code of the affiliate is entered in this coding block, if applicable. The codes in this chartfield are used in preparing consolidated financial statements.
Operating Unit Code	The **Operating Unit** code sub-divides transactions for special reporting purposes largely related to tax reporting, rate case, and other matters. Valid values include, among others, state abbreviations.
Project Costing Business Unit	The **Project Costing Business Unit** connects the transaction with the responsible budgeting group or area for project reporting purposes.
Project ID	The **Project ID** connects the transaction with a budget project. A budget project allows budgeted and actual costs to be captured for managerial reporting purposes.
Work Order	The **Work Order** is the billing mechanism used to capture and bill like costs, and connects the transaction with a planned project that generally has a set beginning date, a projected end date and an estimated cost to complete. Work Orders include construction and retirement work, R&D work, IT projects, non-regulated activities, and other special projects and transactions.

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Transactions

Subject

CHARTFIELDS

	Attached to each **Work Order**, as an attribute, is a Benefiting Location Code that identifies the location or area that benefits from the work (i.e., the activity or project that is being performed). A benefiting location can define, among other things, a power plant, a generating unit at a power plant, or a region. Each benefiting location further defines the company or group of companies that operate in the particular location or area. For example, benefiting location code 1358 is only applicable to Amos Plant Unit 1 and pertains to the Generation ledger for Appalachian Power Company; and, benefiting location code 1178 pertains to the Transmission ledgers of Appalachian Power Company, Kentucky Power Company and Kingsport Power Company.
Cost Component	The **Cost Component** relates the transaction to a specific type of cost such as labor, travel, materials, or outside services.
Activity Code	The **Activity Code** identifies the activity being performed. Examples of defined work activities are: "Respond to Customer Inquiries," "Process Payroll" and "Coordinate Federal Income Tax Returns & Reports." The Activity code directs the billing allocation formula for some work orders.
Resource Sub-Category	The **Resource Sub-Category** sub-divides accounting transactions for cost tracking purposes. Among other things, the resource sub-category is used to track vehicle and building expenditures by vehicle number or building number. Certain equipment maintenance costs are also tracked.

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Section

Time Reporting

Subject

OVERVIEW

SUMMARY

AEP's time reporting systems are designed to collect the chartfield information needed to apportion costs between regulated and non-regulated activities.

TIME RECORDS

Each AEP employee, or a responsible timekeeper, must complete a time record for each pay period.

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LABOR COSTING

The cost of labor makes up a high percentage of the service cost which is apportioned between regulated and non-regulated activities.

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Section

Time Reporting

Subject

TIME RECORDS

SUMMARY

AEP follows a system of positive time reporting whereby all employees, are required, either personally or through an appointed timekeeper, to provide Payroll with a full accounting of their productive and non-productive time classifications. Time records are prepared for each pay period. Examples of non-productive time include vacation time, holidays, jury duty and other paid absences.

FEATURES

Positive time reporting is the process by which each employee accounts for the total number of hours in each pay period, including overtime and paid absences. The positive time reporting process used by AEP encompasses the following features:

- Forms the basis for assigning labor costs by accounting for all activities and time spent by activity on a pay period basis
- Accounts for time in hourly increments as small as a one-tenth of an hour
- Accumulates and summarizes time spent on a reported line-item basis
- Requires all chartfield values needed to account for the time spent and to report labor costs
- Requires the amount of time reported for a given pay period to at least equal the total hours in the pay period
- Does not assume employees are working

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Time Reporting

Subject

TIME RECORDS

FEATURES (Cont'd)

only on regulated activities or only on non-regulated activities. The actual time spent must be reported and classified to the applicable activities and/or projects based on the work performed.

- As employees spend and report time, the cost of the time is directly attributable to regulated and non-regulated operations based on benefiting location or it could apply to an indirect cost pool.

APPROVALS

All time records must be approved by the employee's immediate supervisor or the supervisor's designee. Audit Services performs periodic studies to determine that the time reported by group supervisors has a reasonable relationship to the time reported by their direct reports.

ELECTRONIC PROCESSING

In most cases, time is reported and approved electronically. The reported time is available to be viewed on-line for a period of time before it is archived.

Employees can view their accrued and used vacation hours on-line using AEP's intranet.

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Section

Time Reporting

Subject

LABOR COSTING

SUMMARY

Labor costing is the process of pricing the time reported by employees for the purpose of apportioning their labor cost to the activities that they perform. The cost of labor is a high percentage of the total service cost apportioned among AEP's regulated and non-regulated affiliates.

FEATURES

AEP's labor costing process, in conjunction with time reporting, has been designed to meet the following four criteria:

- it must be practical and cost effective to apply
- it must contain safeguards against material misclassifications between regulated and non-regulated operations and between regulated and non-regulated products and services
- it must be adequately documented
- it must provide an audit trail that can be used for procedural testing and for determining the accuracy of results.

The labor costing process used by AEP employs the following features:

- productive time is priced using the employee's hourly rate of pay which, for salaried employees, is derived by using one of two methods: *(i)* by dividing the employee's annual salary by 2,080 hours, or *(ii)* by dividing the employee's current pay period salary by the total number of hours worked during the pay period (including non-compensated overtime hours worked by exempt employees)

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Time Reporting

Subject

LABOR COSTING

FEATURES (Cont'd)

- non-productive pay is accrued, expensed and distributed as a percentage of labor dollars
- where applicable, the cost of incentive pay and severance pay is also accrued and expensed; and it too follows the distribution of labor dollars.

CONTROLS

Where applicable, appropriate controls are maintained for balancing the total amount of labor cost distributed to the total cost incurred or paid.

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Section

AEPSC Billing System

Subject

OVERVIEW

SUMMARY

AEPSC is a wholly-owned subsidiary of AEP, a registered public utility holding company. AEPSC provides certain managerial and professional services including administrative and engineering services to affiliated companies in the AEP holding company system and periodically to unaffiliated companies.

As a subsidiary service company, AEPSC and its billings are subject to the regulation of the Federal Energy Regulatory Commission (FERC) under the Public Utility Holding Company Act of 2005.

SYSTEM OF INTERNAL CONTROLS

Effective operation of the AEPSC work order billing system is tied to AEP's overall system of internal controls.

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WORK ORDER ACCOUNTING

AEPSC maintains a work order system for allocating and billing costs in accordance with the applicable Uniform System of Accounts for centralized service companies.

03-04-03

BILLING ALLOCATIONS

Billing allocations are performed using Attribution Bases (i.e., Allocation Factors) approved by the SEC under PUHCA 1935 and continued after its repeal.

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REPORTS

AEPSC prepares a monthly billing report for all billed costs.

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AEPSC Billing System

Subject

SYSTEM OF INTERNAL CONTROLS

SUMMARY

Effective operation of AEPSC's work order and billing system is tied to AEP's overall system of internal controls. The more relevant controls and administrative procedures include accountability, allocability, budgeting, time-reporting review and approval, billing review, dispute resolution, periodic service evaluations, and internal auditing.

RESPONSIBILITIES

The business units and process owners who code and approve transactions for processing through the AEPSC billing system are responsible for final results. Employees can access electronic databases that contain titles and descriptions of all applicable codes.

Changes in facts and circumstances that affect the billing process must be addressed in a rapid and responsible manner.

The Corporate Planning and Budgeting group along with Corporate Accounting are responsible for assisting the business units and AEPSC's client companies in evaluating the monthly billing results on a company by company basis. Also see "Billing Review" below.

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AEPSC Billing System

Subject

SYSTEM OF INTERNAL CONTROLS

ALLOCABILITY

Through the transaction coding process, clients are billed only for the services and costs that pertain to them. Shareable costs are billed using allocation factors. The approved billing system is designed to result in a fair and equitable allocation of cost among all client companies, regulated and non-regulated. AEPSC employees are provided information and trained to achieve these results relative to their areas of responsibility.

BUDGETING

Each year AEPSC prepares an annual budget for the services it will provide during the next calendar year. The budgets are prepared by each AEPSC department.

Corporate Planning & Budgeting and Business Unit Budget Coordinators generate monthly performance reports that compare actual cost against the budget. Performance results can be viewed by Department, by Account, or by Activity, and also by Affiliate company.

AEPSC's managers are primarily responsible for analyzing and explaining cost variances incurred while performing their work. Additionally, AEPSC and its affiliates are jointly responsible for analyzing and explaining the cost variances incurred through the AEPSC billings.

AEPSC's annual budgets are consistent with and support AEP's corporate-wide strategic performance objectives. AEP's Board of Directors, with the assistance of executive management, approves the annual budgets for AEPSC, the utility companies and other AEP affiliates.

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AEPSC Billing System

Subject

SYSTEM OF INTERNAL CONTROLS

WORK ORDER PROCESSING REVIEW	The Accounting department reviews requests for new AEPSC Work Orders. The review includes (1) Appropriate descriptions – to ensure that the users will understand the type of costs to be accumulated in each work order. (2) Appropriate benefiting location – to ensure that the proper affiliated company or group of companies will be billed (3) Appropriate billing allocation factor – to verify (based on the work being performed) that the appropriate cost drivers are being used for the type of service being performed such as Number of Employees, Transmission Pole Miles, Number of Retail Electric Customers, or Total Assets.
BILLING SYSTEM CONTROLS	Specific controls related to the billing system include (1) The Accounting department reviews the reasonableness of the statistics, by affiliate company, that are used to allocate costs by comparing them to other statistics, amounts used in prior periods, etc. (2) Reports are generated by the billings system to reconcile/confirm that all amounts were allocated and the total dollars received for processing were billed out. (3) An automatic e-mail is sent to the Accounting department which identifies any errors created during Journal Generation of the AEPSC Bill. (4) The Accounting department confirms the AEPSC net income is zero each month-end to ensure that all expenses incurred were billed. (5) The Accounting department reviews the list of AEP affiliate companies every month to assure billing statistics are accumulated and posted properly for a newly created affiliate companies, or removed for inactivated affiliate companies.

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AEPSC Billing System

Subject

SYSTEM OF INTERNAL CONTROLS

Please see Appendix 99-00-04 for information regarding the billing allocation factors that are used by AEPSC and their update frequency.

PRE-BILLING TRANS-ACTIONS REVIEW

Various controls exist surrounding the detailed accounting transactions that are processed by the AEPSC billing system, including: (1) Numerous edits/validations are performed mechanically at the time transactions are entered into the accounting system. For example, the validation routines will not permit a labor expense Account to be used in conjunction with non-labor costs. (2) Prior to running the monthly AEPSC billing process, Accounting reviews certain accounting transactions to ascertain if any items are misclassified based on certain criteria. Correction entries are prepared, if necessary, prior to the bill processing, For example, transactions charges to income tax FERC expense account should be charged to the income tax work order. (3) An "unbillable" report is run numerous times prior to processing of the bill. This report identifies transactions that will not bill due to recently inactivated Work Orders, invalid combinations of statistics, etc. Correction entries are made as necessary prior to running the bill.

ALLOCATION

Shared costs are billed using approved allocation factors. The billing systems is designed to result in a fair and equitable allocation of cost amount all affiliate companies. As mentioned above under "Responsibilities", information is readily

available to employees to assist with the proper coding of transactions in order to achieve these results relative to their areas of responsibility.

TIME REPORTING REVIEW AND APPROVAL

AEPSC uses positive time reporting whereby time records are submitted by each AEPSC employee, on a bi-weekly basis. Supervisors, or their designated delegates, review and approve the time records for the employees in their respective groups.

In addition to the normal approval process, periodically the Accounting department provides reports to each AEPSC manager for review and validation of their employees; labor charges. The report indicates the companies that each employee billed, the work performed for the company, the labor hours charged, and the work orders(s) used to bill the hours. This report provides an additional control to ensure employees were billing correctly and that their managers concurred with the billing. Managers were required to sign the report indicating their review and approval, and return the signed copy to Accounting. If a manager has questions about an employee's time charges, or believes a correction is required, the manager communicates those concerns to Accounting.

AFFILIATED BILLING REVIEW

Monthly, Regulated Accounting sends reports to the State Operating Companies Regional Presidents (and/or their staff), and other members of management, for their review and approval of the AEPSC Work Order billing by affiliate company.

The services performed and the amounts

billed are reviewed for accuracy on behalf of the regulated utilities and AEPSC's other affil-iated clients. The performing organizations initiate all needed corrections and Corporate Accounting processes the corrections.

DISPUTE RESOLUTION

The monthly AEPSC billings to the affiliate Operating companies are submitted to the AEP state Business Operations Support groups for their review and approval. The AEPSC bill approval process for the Business Operations Support groups includes various steps. Monthly, Directors review the AEPSC departments allocating costs to their companies to determine whether it appears reasonable for each department to be allocating to that operating company. Also monthly, Directors notify AEPSC of their approval of the monthly AEPSC billing, noting any issues needing resolved as a result of their monthly review. Any issues arising from the above reviews are coordinated through the affected AEPSC department and the AEPSC Controllers department, which will be responsible for resolving issues raised by the operating companies and making appropriate adjustments. Each of the above steps is documented, including approvals, explanations of variances, and any adjustments resulting from this review and approval process. Directors are responsible for retaining documentation for a minimum of two years.

If a resolution cannot be reached among the parties, the dispute is referred to the Chief Financial Officer or another

appropriate member of executive management.

SERVICE EVALUATIONS

Internal customer input and an internal customer-oriented philosophy are necessary in order to keep AEPSC operating efficiently and at cost-competitive levels.

Internal customer surveys are used to measure performance and internal customer satis-faction. The internal customer surveys, along with the budgeting process and service level agreements, are used to seek customer input relative to the quantity, quality and value of the various services being provided by AEPSC to other groups within the AEP holding company system.

Whenever feasible, and to the extent necessary, cost levels and business practices are benchmarked against other companies both within and outside the electric utility industry.

INTERNAL AUDITING

The AEPSC Audit Services department performs periodic audits of the AEPSC billing system. The purpose of the audits is to examine the internal controls over the billing process and to ascertain that billing allocations are being performed in accordance with the approved Allocation Factors and in accordance with the Service Agreements AEPSC has with its affiliated clients.

EXTERNAL AUDITING

Annually, AEPSC provides unaudited financial statements to various banks and leasing companies. In addition, the applicable banks and leasing companies have access to AEP Consolidated financial statements, which are audited by Price Waterhouse Cooper. The

audited AEP Consolidated financial statements include an audit of various transactions through the billing system to verify accuracy of the procedures and amounts billed to affiliates.

STATE AND FEDERAL AUDITS AND REPORTING

STATE AUDITS: AEPSC is subject to periodic state affiliate and code of conduct audits, in order to comply with certain state regulatory requirements. For example, Texas requires an affiliated code of conduct audit every three years.

FERC AUDITS: Effective with the passage of the Public Utility Holding Company Act of 2005 (which became effective February 6, 2006) AEPSC is now regulated by the Federal Energy Regulatory Commission, and as such is subject to FERC oversight and audit.

FERC REPORTING: The FERC requires a detailed annual financial report for services companies, the FERC Form 60. This report contains detailed AEPSC information, including amounts billed to each affiliate company.

These periodic audits and annual reporting requirements provide additional controls governing AEPSC's accounting routines, financial transactions, and billing to affiliates.

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Section

AEPSC Billing System

Subject

Work Order Accounting

SUMMARY

AEPSC uses a work order system for the accumulation of cost on a job, project or functional basis. It includes schedules and worksheets used to account for charges billed to single and groups of associate and nonassociate companies.

COST IDENTIFICATION

As a subsidiary service company, AEPSC identifies billable costs using two separate chartfields (i.e., transaction coding blocks); namely,

- Activity (through General "G" Work Orders) and
- Work Order.

Each of these chartfields is defined elsewhere in this manual (look up "Chartfields" in the Table of Contents or the Alphabetic Subject Index to determine the applicable Document Number).

General (i.e., "G") work orders have been established to assign the benefiting location to general services that are billed by "Activity".

FUNCTION AND TYPES OF WORK ORDERS

A billable cost is derived by using a Work Order or Activity with a Benefiting Location (including "G" Work Orders). While Work Order and Activity define the nature of the service performed, the Benefiting Location identifies the company or group of companies for which the service is performed. Benefiting Location is not a chartfield, but it is an attribute of each billable Work Order. AEPSC uses the following types of Work Orders

FUNCTION AND TYPES OF WORK ORDER (Cont'd)

(billable and non-billable):

Direct – A Direct Work Order is used when the service being provided benefits a single company or company segment. The monthly cost accumulated for a Direct Work Order is billed 100% to the company for which the service was performed as designated by the benefiting Location code associated with the service.

Allocated – An Allocated Work Order is used when the service being performed benefits two or more companies or company segments. The monthly cost accumulated for an Allocated Work Order is allocated and billed to the companies for which the service is performed as designated by the Benefiting Location code associated with the service.

The AEPSC billing system uses specific company cost-causative Allocation Factors to allocate costs that are accumulated under Allocated Work Orders.

SCFringe – The SCFringe Work Order is used to accumulate the cost of labor-related overhead. Labor-related overhead includes, among other things, payroll taxes and employee benefits such as pension and medical expense.

SCFringe is charged to client companies in proportion to the distribution of AEPSC's labor dollars.

FUNCTION AND TYPES OF WORK ORDER (Cont'd)

While not part of SCFringe, it should be noted that the cost of compensated absences such as vacation and holiday pay is also charged to client companies based on the distribution of AEPSC's labor dollars.

AEPSC Departmental Overhead – Information Technology, Human Resources, and Real Estate and Workplace Services all provide services to AEPSC Departments. Therefore, the portion of an Information Technology, Human Resources, or Real Estate and Workplace Services work orders that relate to AEPSC is allocated to the AEPSC departments that benefit from the service based on number of workstations (Information Technology), number of employees (Human Resources), and occupancy (Real Estate and Workplace Services). The AEPSC departments' share of the costs is then allocated to the client companies in proportion to the labor charged by each AEPSC department to the client companies.

Internal Support Costs Overhead – The Internal Support Costs (ISC) Overhead Work Order is used to identify the expenses incurred in support of AEPSC's overall operations. ISC includes all expenses identified with work order G0000103, which has an attribute of Benefiting Location 103 (the code for AEPSC). For example, the expenses incurred in processing the payroll for AEPSC's employees and in paying AEPSC's vendors are included in ISC overhead is

allocated to client companies in proportion to the total cost charged to each company.

ACTIVITY AND WORK ORDER REQUESTS

Service requests fall into two major categories:

- Activity, and
- Work Order.

As the overseer of the budgeting process, AEPSC's Corporate Planning and Budgeting group is responsible for approving all requests for adding or deleting Activities. The Corporate Planning and Budgeting group processes all requests for opening or closing new Activities while the Regulated Accounting group processes all requests for new AEPSC Work Orders.

The ABM Activity Request Form – This form requires the following information:

Line Item	Information
Requested By	Name of requestor. Electronic requests are automatically populated with requestor's required information, date and time.
Effective Date	The requesting business unit recommends an effective date for use of the new activity.
Activity Number	The requesting business unit provides the Activity Number only when an existing activity is being

Line Item	Information
	changed.
Activity Description	The requesting business unit provides the proposed title of the new activity (e.g., "Develop Coal Delivery Forecast").
Process Group	The requesting business unit provides the name of the high-level process group to which the new activity is related (e.g., "Generate Energy").
Major Process	The requesting business unit provides the name of the high-level major process to which the new activity is related (e.g., "Procure, Produce & Deliver Fuel").
Business Process	The requesting business unit provides the name of the high-level business process to which the activity is related (e.g., "Procure Coal").
Purpose and Use	The requesting business unit provides a description of the new activity, its purpose and use.
Task List	Provide a list of all the steps and preparation undertaken to arrive at the request.
Suggested FERC Accounts	The requesting business unit provides the suggested FERC account.
Service Corp Attribution Basis	The requesting business unit recommends an Allocation Factor for use.

Line Item	Information
Cost Drivers	The requesting business unit provides the reasons for the request.

See the ILLUSTRATIONS at the end of this document for a copy of the Activity Request Change Form.

Work Order Request Form – This form requires the following information:

Line Item	Information
Recommended Title	The requesting business unit provides the recommended work order title.
Project Costing Business Unit	The requesting business unit provides the Project Costing Business Unit identification.
Budget Project	The requesting business unit provides the applicable Budget Project code.
Work Order Type	The requesting business unit provides the Work Order type.
Estimated Total Costs to be incurred by AEPSC	The requesting business unit supplies the estimated cost of the work performed.
Estimated Duration	The requesting business unit provides the start and the estimated completion date.
Description of Service(s) To Be Rendered	The requesting business unit supplies a description of the work order

Line Item	Information
	based on the nature and scope of the project to be performed.
Benefiting Location	The requesting business unit supplies the applicable benefiting location code based on the company or class of companies that will benefit from the work order. The requester can select the benefiting location code either by Name or by Number. The benefiting location will become an attribute of the work order.
Recommended Allocation Factor	The requesting business unit supplies the recommended Allocation Factor code for the work order. The Allocation Factor code identifies the proposed method of allocation for Allocated work orders. The Allocation Factor becomes an attribute of the work order. Work orders that pertain to a single company should be assigned an Allocation Factor code of "39, Direct".

Line Item	Information
Shared Services	The requesting business unit must indicate if this is a work order to be used by Human Resources, Information Technology and Real Estate and Workplace Services. If "Yes" is selected, then the requestor is required to select the appropriate department for the shared service organization. This will be used as part of the AEPSC Departmental Overhead.
Additional Remarks	The requesting business unit provides any special project or accounting instructions related to the work order or makes reference to any attachments.
Others To Be Notified When Request Is Approved	The requesting business unit provides a list of employees to be notified when the work order is opened for charges.
Are you the Sponsoring Supervisor for This Request?	The requester must indicate if he or she is the sponsoring supervisor for this work order request.
Other Reviewers	The sponsoring supervisor must approve the request. In addition, the Corporate Accounting group must accept or decline each request.

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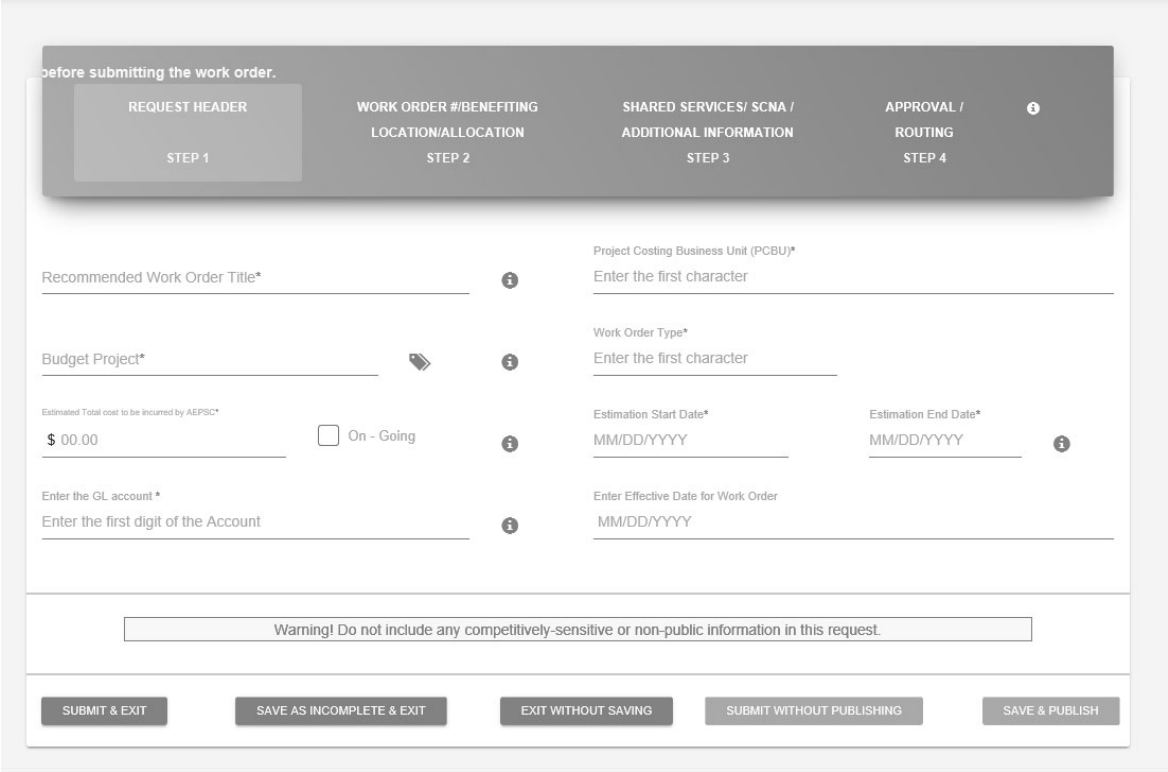
Work Order Accounting

See the ILLUSTRATIONS at the end of this document for a copy of the Work Order Request Form.



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AEPSC Billing System

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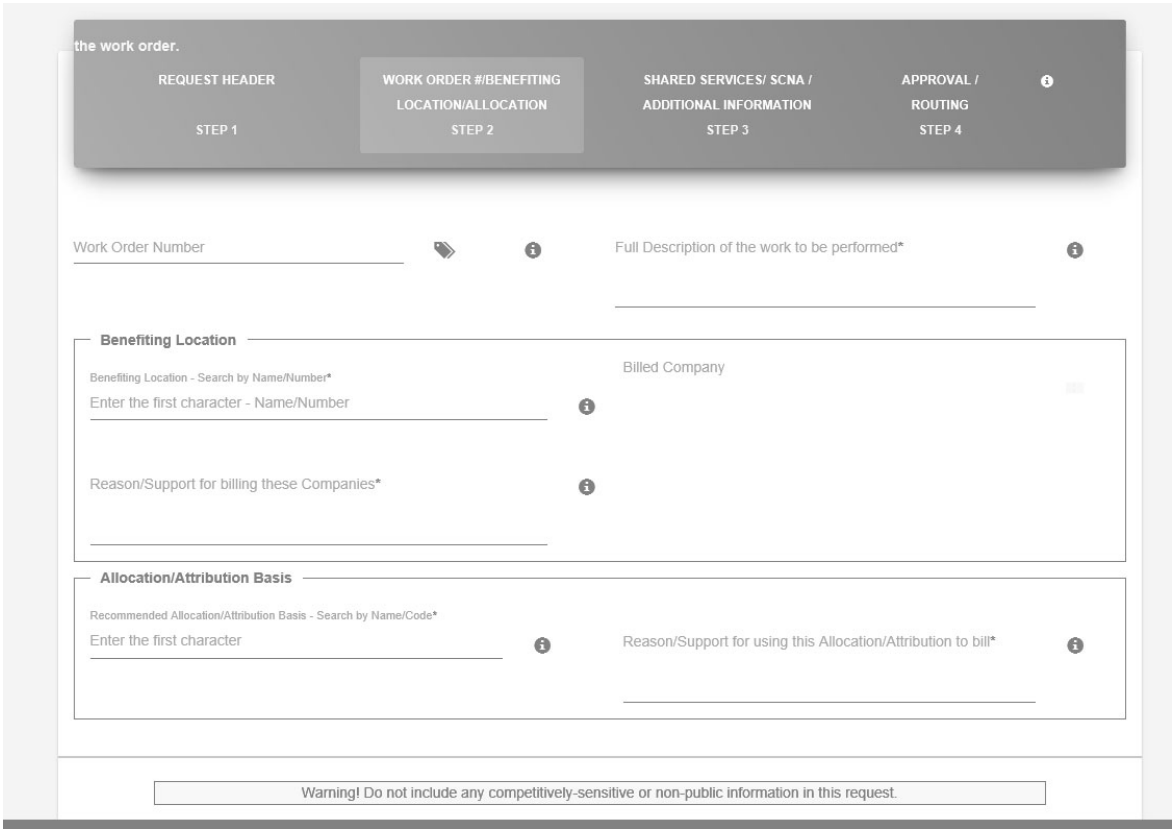
Work Order Accounting



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AEPSC Billing System

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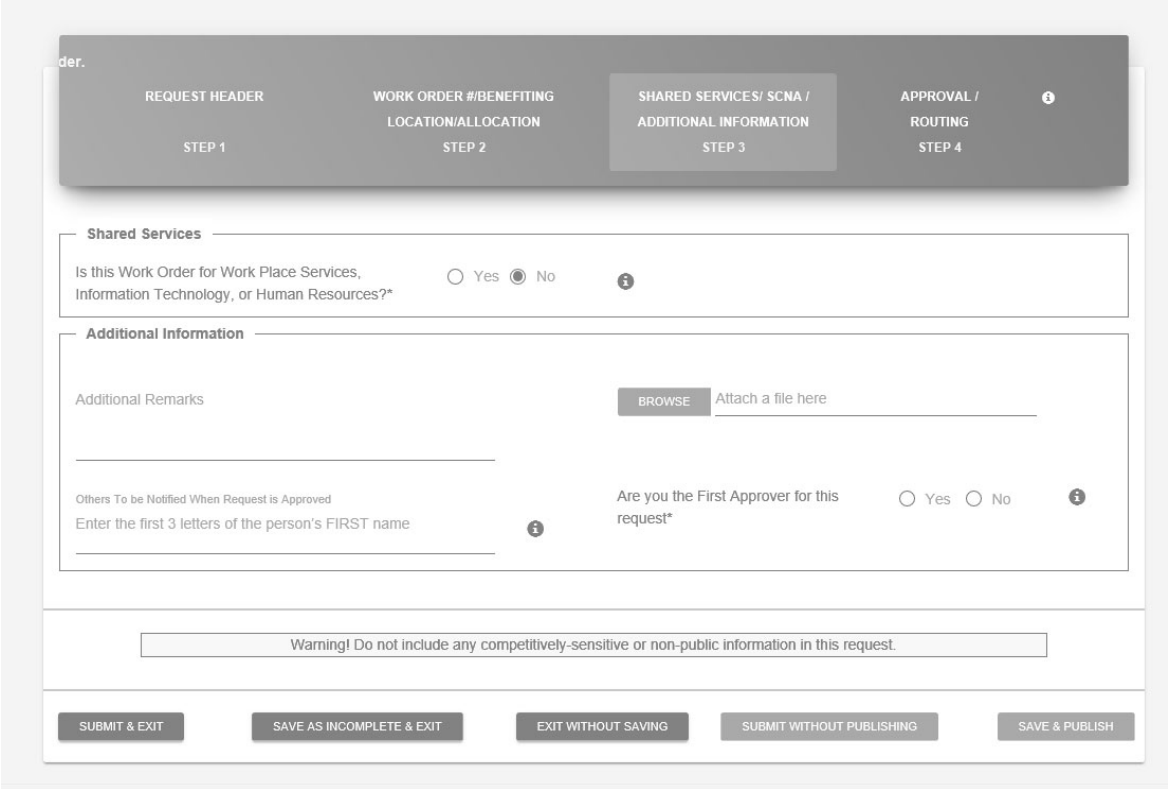
Work Order Accounting



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Document Number **03-04-04**

Cost Allocation Manual

Section

AEPSC Billing System

Subject

BILLING ALLOCATIONS

SUMMARY

Each Allocated Service ID, whether related to an Activity or a Work Order, is assigned an appropriate Allocation Factor code that, along with the Benefiting Location code, ultimately determines the dollars of cost that will be charged to each client company. Allocation Factor codes are assigned according to the nature of the services performed.

Each Direct Service ID is assigned an Allocation Factor code of "39" which is fixed at 100%.

FUNCTION OF THE ALLOCATION FACTOR CODE

The Allocation Factor code identifies the statistical factor that will be used to calculate the percentage of cost applicable to each client company. The assigned code points to a table that includes the company-specific values needed to calculate the allocation percentages.

ROLE OF REGULATED ACCOUNTING

An accounting administrator in the Regulated Accounting group has primary responsibility for ensuring that the Allocation Factor code assigned to each Allocated Service ID is relevant to the service being performed. Regulated Accounting is also responsible for ensuring that the company-specific statistical values needed for each Allocation Factor are accurate and kept up to date. The values are refreshed according to the intervals determined for each Allocation Factor (e.g., monthly, quarterly, semi-annually and annually).

The Allocation Factor assigned to each Allocated Service ID should be the most relevant cost-causative cost driver.

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Cost Allocation Manual

Section

AEPSC Billing System

Subject

BILLING ALLOCATIONS

PROCESS

The requestor of a new Activity or Work Order is required to recommend an appropriate Allocation Factor code. Requestors are in the best position to recommend an appropriate Allocation Factor code since they are intimately familiar with the work to be performed and with the inherent cost drivers. Regulated Accounting reviews all Allocation Factor code selections for reasonableness.

EXAMPLES

Examples of the appropriate use of Allocation Factors are captured in the following table:

Activity/Shared Service	Allocation Factor
191. Maintain Transmission Right-of-Way	28. Number of Transmission Pole Miles
340. Process payroll	09. Number of employees
663. Perform Stores Accounting	26. Number of Stores Transactions

LIST OF APPROVED ALLOCATION FACTORS

The APPENDIX to this manual contains a list of all the approved Allocation Factors.

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Cost Allocation Manual

Section

AEPSC Billing System

Subject

REPORTS

SUMMARY

An electronic journal entry is created by the AEPSC billing system as part of the billing process to record the accounts receivable and revenue on AEPSC's books, and to record the corresponding distribution and accounts payable on the associate companies' books (billing interface).

BILL FORMAT

The following represents a view of the monthly bill for services rendered by AEPSC to an associate company:

AUDIT TRAIL

An audit trail is maintained for all AEPSC billing system transactions starting with the source documents all the way through general ledger posting.

The AEPSC billing system produces a journal entry that is posted to each respective company's general ledger on a monthly basis. The mask for this journal entry is "SCBBILxxxx". The alpha section of the mask is constant. The numeric section of the mask is assigned the next available journal entry number each month for each company.

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Cost Allocation Manual

Section

Intercompany Billing

Subject

OVERVIEW

SUMMARY

The PeopleSoft general ledger system used by AEP allows transactions to be coded for intercompany billing.

BILLING SYSTEM

AEP's intercompany billing process automates the accounting for costs incurred by one AEP System company for the exclusive or mutual benefit of one or more affiliates.

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Cost Allocation Manual

Section

Intercompany Billing

Subject

BILLING SYSTEM

SUMMARY

Intercompany billing of O&M and capital costs automates the accounting for work performed by one company for the exclusive or mutual benefit of one or more affiliates. This process allows the performing company to incur the cost and bill it to the appropriate benefiting company or companies. All intercompany billing transactions between companies are summarized on a monthly basis, resulting in one net billing between companies.

USES

Intercompany billing is used most often to share operating expenses or when one company performs services for another company. The Affiliate Transaction Agreement, dated December 31, 1996, and the Mutual Assistance Agreement, dated July 30, 1987 provide the basis of the intercompany billing.

Costs incurred which are subject to intercompany billing can include, among other costs, O&M or capital company labor including appropriate transportation and labor fringes, purchased materials or services, materials issued from company storerooms, and rental charges for use of another company's facilities.

CODING REQUIREMENTS

The initiation of the intercompany billing process requires the proper use of chartfield values. An intercompany billing transaction is initiated whenever a benefiting location number is different than the performing company's business unit code. Benefiting location numbers can be either 100% billed or shared among multiple companies. A 100% billed and a multiple company benefiting location example follow:

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Section

Intercompany Billing

Subject

BILLING SYSTEM

CODING REQUIREMENTS (Cont'd)

Example: 100% billed Benefiting Location

The duties performed by the West Virginia Rates Department benefit the AEP customers within the state of West Virginia. Both Appalachian Power Company and Wheeling Power Company - Distribution serve customers in West Virginia. All Rates Department employees serving West Virginia are on the payroll of Appalachian Power Company.

Whenever the Rates Department performs work exclusively on a Wheeling Power Company - Distribution rate case, their labor and expenses are classified to benefiting location 210. The use of 210 benefiting location results in a 100% billing to Wheeling Power Company - Distribution. This intercompany billing establishes an accounts receivable entry for Appalachian Power Company, the performing company, and a corresponding accounts payable entry for Wheeling Power Company - Distribution, the company benefiting from the work.

Example: Shared Benefiting Location

An invoice is received for aerial patrol services performed for the Central Transmission Region. Since this work has been performed for the benefit of all five companies served by the Central Transmission Region, the processing company charges a multiple company benefiting location. This multi-company benefiting location shares the cost among the five companies served by the Central Transmission Region.

Since the invoice pertains to transmission

services, the cost incurred will be allocated among the five companies using an Allocation Factor of transmission pole miles. This intercompany billing establishes an accounts receivable entry for the performing company and a corresponding accounts payable entry for the four remaining benefiting companies.

INTERCOMPANY BILLING COST ALLOCATIONS

All intercompany billing allocations are either direct (i.e., 100%) or are allocated among the appropriate companies based on the applicable multi-company benefiting location code. Every multi-company transaction is allocated using one of the approved Allocation Factors for service company billings. The Allocation Factor must be appropriate for the function for which the cost is incurred. For example, cost incurred for the performance of transmission services would be allocated using an Allocation Factor of number of transmission pole miles.

AUDIT TRAIL

An audit trail is maintained for all intercompany billing transactions starting with the source documents all the way through general ledger posting.

The intercompany billing procedure produces journal entries that are posted to each respective company's general ledger on a monthly basis. The journal entry mask for the intercompany billing process is "INTCOMxxxx". The alpha section in each mask is constant. The numeric section of the masks is assigned the next available journal entry number each month for each company.

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Section

Intercompany Billing

Subject

BILLING SYSTEM

Any given intercompany journal entry can contain several thousand lines of data each month.

The accounts receivable and accounts payable transactions created by the intercompany billing process are assigned account numbers 1460006 and 2340027, respectively.

CASH SETTLEMENT

Intercompany billing transactions are settled through the AEP money pool among money pool participants. Non-money pool participants settle-up through cash disbursements.

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Document Number **03-06-01**

Cost Allocation Manual

Section

InterUnit Accounting

Subject

OVERVIEW

SUMMARY	The PeopleSoft general ledger and accounts payable systems used by AEP allow transactions to be recorded that pertain to two or more companies.
JOINT PAYMENTS AND JOURNAL TRANSACTIONS	InterUnit accounting can be applied to accounts payable processing or general ledger journal entry processing.

03-06-02

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Cost Allocation Manual

Section

InterUnit Accounting

Subject

JOINT PAYMENTS AND JOURNAL TRANSACTIONS

SUMMARY

InterUnit accounting automates the process of accounting for transactions that affect two or more affiliated companies. The process automatically generates the general ledger transactions applicable to each company. All InterUnit accounting transactions are summarized on a daily basis, resulting in a net amount due to and from each company, by affiliated company.

USES

InterUnit accounting can be applied to accounts payable processing, accounts receivable processing, or to general ledger journal entry processing.

InterUnit accounting is used whenever one company (i.e., business unit) processes a vendor invoice, deposits funds, or classifies journal entry transactions that pertain to one or more other affiliated companies.

The InterUnit accounting feature within the PeopleSoft software saves time, reduces processing costs, accurately creates reciprocal transactions, and provides for an efficient settlement routine. It simplifies the intercompany billing process by eliminating the need to prepare and handle paper billings. A complimentary process also summarizes and nets the daily InterUnit activity that occurs between companies.

CODING REQUIREMENTS

InterUnit accounting requires the proper use of business unit codes. An InterUnit transaction is initiated by entering a business unit code on a transaction classification line that is different from the processing company's business unit code.

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Cost Allocation Manual

Section

InterUnit Accounting

Subject

JOINT PAYMENTS AND JOURNAL TRANSACTIONS

CODING REQUIREMENTS

The uses of InterUnit accounting and the related coding requirements are illustrated by the following three examples:

Example of invoice processing through accounts payable:

An invoice is received for legal services performed for six of AEP's generating companies. Since the invoice pertains to more than one company, the invoice can be processed by one of the companies using at least six lines of accounting classification; that is, one line for each company. InterUnit accounting will be triggered for all the lines of classification that have a business unit code that is different from the processing company's business unit code.

For each line of classification with a different business unit code, the InterUnit accounting process will establish a receivable from associated companies on the processing company's books and a payable to associated companies on the applicable affiliate companies' books. In addition, the balance sheet and expense transactions actually coded on the original accounts payable voucher will automatically be posted to the books of the applicable companies based on the business unit codes that are used.

Example of receipt processed through accounts receivable:

A single wire transfer is received for materials sold by three of AEP's distribution companies. The customer

received three separate invoices, one from each distribution company, but chose to wire funds to only one of AEP's distribution companies for full payments to eliminate incurring multiple wire fees.

CODING REQUIREMENTS (Cont'd)

The Billing and Accounts Receivable section will apply payment to each distribution company invoice by reflecting the deposit company (i.e.: business unit), which receipted for the wire transfer. Two of the company invoices will have an invoicing business unit different than the deposit business unit. For these two invoices, the InterUnit accounting process will establish a receivable from associated companies on the company rendering the invoice, and a payable to associated companies on the company that deposited the funds. In addition, the bill classification will be relieved on the company that issued the bill to the customer.

Example of general ledger journal entry processing:

A single company (i.e., business unit) operates a messenger delivery service for itself and several affiliates. Corporate Services provides Accounting Services with the amounts to be billed each month to the other companies based on their actual use of the services.

Since this is a recurring transaction, an InterUnit journal entry can be pre-coded with the appropriate chartfield codes, including the applicable business unit

codes. The dollar amounts to be billed to the business units and the date of the transaction are the only variables required for journal entry preparation.

When processed, the InterUnit journal entry will record the charges on the benefiting affiliated companies' books and establish an associated company accounts payable. The

CODING REQUIREMENTS (Cont'd)

journal entry will also record the appropriate associated company accounts receivable entries and offset the original charges on the performing company's books. The debits to accounts receivable from associated companies and the credits to accounts payable to associated companies are automatically generated for each journal entry line item that has a business unit code that is different from the performing company's business unit code.

INTERUNIT ACCOUNTING

For InterUnit accounting purposes, the amount applicable to each company must be coded using separate detail lines. The amount for any transaction that pertains to two or more companies should be allocated using one of the approved Allocation Factors for service company billings. The Allocation Factor selected must be appropriate for the type of cost being allocated based on the nature of the activity or project for which the cost is incurred.

AUDIT TRAIL FEATURES

An audit trail is maintained for all InterUnit transactions starting with the source documents all the way through to the general ledger postings.

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Cost Allocation Manual

Section

InterUnit Accounting

Subject

JOINT PAYMENTS AND JOURNAL TRANSACTIONS

The InterUnit transactions processed through Accounts Payable and Billing and Accounts Receivable are posted to the general ledger through the daily distribution interfaces. InterUnit journal entries are posted directly to the general ledger.

InterUnit transactions can be viewed on-line through simple queries where the "Business Unit does not equal Business Unit_GL" for accounts payable transactions, where the "Business Unit does not equal Deposit_BU" for accounts receivable, or where the "Business

AUDIT TRAIL FEATURES (Cont'd)

Unit does not equal Business Unit_IU" for general ledger journal entries.

InterUnit accounting creates the affiliated accounts receivable and accounts payable transactions. Account numbers are assigned as follows:

1) if the accounting is generated by either journal entries or Billing and Accounts Receivable, accounts 1460001 and 2340001 reflect the reciprocal receivable and payable, or
2) if InterUnit accounting is generated by Accounts Payable, accounts 1460009 and 2340030 reflect the reciprocal receivable and payable.

AFFILIATED SETTLEMENTS

A settlement process is initiated daily for all InterUnit transactions. Corporate and General Accounting supplies a file to Treasury summarizing each company's net affiliated position for InterUnit transactions. A net payable position results in either increased short-term

borrowings or decreased short-term investments in the AEP money pool among money pool participants. A net receivable position results in either increased short-term investments or decreased short-term borrowings in the AEP money pool among money pool participants. Non-money pool participants settle through cash disbursements.

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Document Number **03-07-01**

Cost Allocation Manual

Section

Asset Transfers

Subject

OVERVIEW

SUMMARY

AEP companies, especially AEP's electric utilities, sell plant and equipment among themselves. AEP companies also sell materials and supplies to each other.

PLANT AND EQUIPMENT

Plant and equipment generally is sold "at cost" (i.e., net book value) to associate companies in the AEP holding company system.

03-07-02

MATERIALS AND SUPPLIES

Materials and supplies are generally sold to associate companies "at cost" using the selling company's average unit inventory cost.

03-07-03

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Cost Allocation Manual

Section

Asset Transfers

Subject

PLANT AND EQUIPMENT

SUMMARY

The physical integration of AEP's power plants and its many circuit miles of transmission and distribution lines and the use of common parts and equipment allow the AEP companies to achieve cost savings by combining their purchasing needs and improving their ability to respond rapidly to emergency situations throughout the entire network.

Such benefits are achieved in part through exchanges of plant and equipment among affiliated utility companies as conditions warrant. The exchanges take place either through rental arrangements (i.e., loans) or through direct sales.

GUIDELINES

Sales

Sales between affiliated regulated utility companies will be transacted at original cost less depreciation, except as permitted by any other applicable order filed with FERC or required by state rule. Sales from regulated affiliates to non-regulated affiliates are priced at higher of cost or market. Sales from non-regulated affiliates to regulated affiliates are priced at lower of cost or market. As allowed by FERC waiver, capitalized spare parts will continue to be transferred between AEP East Utility Companies and AGR at net book value.

AEP Legal-Regulatory is to be informed for the purpose of determining whether any regulatory approvals must be sought.

Loans

Rental fees for loaned property shall cover

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Asset Transfers

Subject

PLANT AND EQUIPMENT

all applicable costs. Such costs include cost of capital, depreciation, and taxes.

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Section

Asset Transfers

Subject

MATERIALS AND SUPPLIES

SUMMARY

AEP's material management groups along with procurement personnel can initiate requests to transfer materials and supplies (M&S) from one AEP storeroom to another. M&S sent from one company's storeroom to an associate company's storeroom results in a sale between companies.

MONTHLY BILLS TO ASSOCIATE COMPANIES

The company owning the part generates a Monthly bill for M&S shipped during the month to an associate company. This method is used very rarely since most transfers occur through the inter-company journal entries. Each item sold is priced "at cost" using the seller's average unit inventory cost. Stores expense is added as appropriate. All sales are recorded through associated company accounts receivable and accounts payable (i.e., Accounts 146 and 234, respectively).

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Cost Allocation Manual

Section

Introduction

Subject

OVERVIEW (DOCUMENTS)

SUMMARY	AEP's state regulatory commissions require certain documents to be maintained in connection with the transactions AEP's regulated utilities have with their affiliates. In some cases, the documents need to be maintained as part of the utility company's Cost Allocation Manual (CAM).
AFFILIATE CONTRACTS	This manual provides a brief description of all contracts and agreements AEP's regulated utilities have with their affiliates. **04-02-01**
DATABASES	Certain databases have been established for reference purposes. The databases described in this manual provide additional information concerning certain subjects in the manual. **04-03-01**
JOB DESCRIPTIONS	The Public Utilities Commission of Ohio requires the job descriptions of certain shared and transferred employees to be maintained as part of the electric utility's CAM. **04-04-01**
COMPLAINT LOG	The Public Utilities Commission of Ohio requires each electric utility to maintain a log of the complaints the utility receives in connection with the Commission's corporate separation rules. The Commission requires the electric utility to include the complaint log in its CAM.

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Cost Allocation Manual

Section

Introduction

Subject

OVERVIEW (DOCUMENTS)

04-05-01

BOARD OF DIRECTORS

The Public Utilities Commission of Ohio requires each electric utility in Ohio to keep a copy of the minutes from its board of directors meetings in its CAM.

04-06-01

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Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
OVERVIEW

SUMMARY

The AEP System's regulated utilities provide products and services to affiliates and receive products and services from affiliates under various contracts and agreements. Copies of the contracts and agreements are maintained in an electronic database that is incorporated in this manual by reference.

SERVICE AGREEMENTS

AEP's electric utilities receive services from AEPSC. The electric utilities provide incidental services to each other as well as to AEPSC.

04-02-02

MINING AND TRANSPORTATION

AEP System affiliates provide coal mining, coal preparation and coal handling services as well as transportation services to AEP's regulated utilities.

04-02-03

CONSULTING SERVICES

Engineering and consulting services are provided by AEP's regulated utilities to certain non-regulated affiliates and vice versa.

04-02-04

JOINT OPERATING AGREEMENTS

Certain AEP facilities are jointly owned and operated.

04-02-05

TAX AGREEMENT

American Electric Power Company, Inc. and its AEP System affiliates file a consolidated Federal income tax return and

share the consolidated tax liability.

04-02-06

MONEY POOL AGREEMENT

AEP and certain of its regulated subsidiaries participate in the AEP System Money Pool. The Money Pool is designed to efficiently match the available cash and short-term borrowing requirements of their participants, minimizing the need for them to borrow from external sources.

04-02-07

NONUTILITY MONEY POOL AGREEMENT

AEP, and certain of its unregulated subsidiaries participate in the AEP System Nonutility Money Pool. The Nonutility Money Pool is designed to efficiently match the available cash and short-term borrowing requirements of their participants, minimizing the need for them to borrow from external sources.

04-02-08

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Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
SERVICE AGREEMENTS

SUMMARY	AEPSC provides various services to the AEP System's regulated utilities and non-regulated affiliates under a standard service agreement with each of the companies served. The regulated utilities also provide services to each other and to AEPSC under other agreements.
AEPSC SERVICE AGREEMENT	AEPSC has a service agreement, in a standard format, with each of the AEP System companies it serves. All agreements are dated June 15, 2000, unless the client company was formed after that date. In addition APCO and Wheeling have updated service agreements dated May 15, 2008. The types of services provided by AEPSC are listed in Document Number **01-03-02** by category and description.
AEPSC SERVICE AGREEMENT WITH TRANSMISSION COMPANIES	AEPSC has a service agreement, in a standard format, with each of the AEP Transmission companies it serves. The agreements have various effective dates depending on when the client company was formed. The types of services provided by AEPSC are included in the list in Document Number **01-03-02** by category and description.
AFFILIATED TRANSACTIONS AGREEMENT	The Affiliated Transactions Agreement, dated December 31, 1996, is among Appalachian Power Company, Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011), Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company and AEPSC. This agreement covers the provision of

incidental services, the sale of goods, and use of facilities and vehicles among the participating companies.

OPERATING COMPANY SERVICE AGREEMENT WITH TRANSMISSION COMPANIES

Each Transmission company has a standard affiliate service agreement with the operating company in its jurisdiction. The agreements have various effective dates depending on when the Transmission Company was formed.

This agreement covers services in connection with the operation of each Transmission Company's transmission assets. The agreements also contain a provision appointing the operating company as agent for licensing space on the transmission company's facilities.

CSW SYSTEM GENERAL AGREEMENT

The CSW System General Agreement, effective June 1, 1999, is among AEPSC, Central Power and Light, now AEP Texas Central, Public Service Company of Oklahoma, Southwestern Electric Power Company, West Texas Utilities Company, now AEP Texas North and other CSW subsidiaries including CSW Energy, Inc., CSW International, Inc., CSW Credit, Inc., CSW Leasing, Inc., C3 Communications, Inc., CSW Energy Services, Inc., and EnerShop Inc. AEPSC is the successor of Central and South West Services, Inc.

This agreement is intended to provide written
documentation governing certain transactions between the CSW electric operating companies and by and between the CSW electric operating companies and other CSW subsidiaries to the extent such matters are

	not addressed in other written agreements.
MUTUAL ASSISTANCE AGREEMENT	The Mutual Assistance Agreement, dated July 30, 1987, is among Appalachian Power Company, Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011), Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company. This agreement allows any participating company to request emergency aid from any one or more of the other participating companies for the purpose of restoring electric service caused by natural disasters and other emergencies.
CENTRAL MACHINE SHOP AGREEMENT	The Central Machine Shop Agreement, dated January 1, 1979, is among Appalachian Power Company and the Companies affiliated with American Electric Power, Inc. This agreement covers machine shop services provided by Appalachian Power Company to affiliates within the AEP System.
SYSTEM INTEGRATION AGREEMENT	The System Integration Agreement, as amended, is among Appalachian Power Company, Kentucky Power Company, Ohio Power Company, Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011), Indiana Michigan Power Company, and their agent AEPSC; Public Service Company of Oklahoma, Southwestern Electric Power Company, and AEPSC. This agreement provides the contractual

basis for coordinated planning, operation, maintenance of the power supply resources of the AEP East Zone and the AEP West Zone to achieve economies consistent with the provision of reliable electric service and an equitable sharing of the benefits and costs of such coordinated arrangements. This agreement is intended to apply in addition to and not in lieu of the AEP Interconnection Agreement and [CSW] Operating Agreement.

Power Coordination Agreement

The Power Coordination Agreement ("PCA"), effective 1/1/2014, is among Appalachian Power Company ("APCo"), Indiana Michigan Power Company ("I&M"), Kentucky Power Company ("KPCo"), and, effective 6/1/2015, Wheeling Power Company ("WPCo" and, collectively with APCo, I&M, and KPCo, the "Operating Companies"), and American Electric Power Service Corporation ("AEPSC") as agent to APCo, I&M, KPCo, and WPCo.

This agreement provides for a contractual basis for coordinating the power supply resources of the Operating Companies to achieve economies and efficiencies consistent with the provision of reliable electric service and an equitable sharing of the benefits and costs of such coordinated arrangements. This Agreement is based on the premise that each Operating Company will maintain sufficient long-term power supply resources to meet its Internal Load requirements. Further, the PCA allows, but does not obligate, the Operating Companies 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.

Bridge Agreement	The Bridge Agreement, effective 1/1/2014, is among Appalachian Power Company ("APCo"), Indiana Michigan Power Company ("I&M"), Kentucky Power Company ("KPCo"), Ohio Power Company ("OPCo" and, collectively with APCo, I&M and KPCo, the "Operating Companies"), AEP Generation Resources Inc. ("AEP Generation Resources") and American Electric Power Service Corporation ("Agent" and, collectively with APCo, I&M, KPCo, OPCo and AEP Generation Resources, the "Parties"). This agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of the Operating Companies that extend beyond termination of the Interconnection Agreement
OPERATING AGREEMENT	The [CSW] Operating Agreement (CSW no longer exists), dated January 1, 1997, is among CSWS, Central Power and Light Company, Public Service Company of Oklahoma, Southwestern Electric Power Company and West Texas Utilities Company. A restated and amended operating agreement for Public Service Company of Oklahoma and Southwestern Electric Power Company was signed December 21, 2001. This agreement provides the contractual basis for a single interconnected electric system through the coordinated planning, construc-tion, operation, and maintenance of the above mentioned companies' electric supplies. CSWS has been designated to act as Agent for this agreement.

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Section
Affiliate Contracts with Regulated Companies

Subject
SERVICE AGREEMENTS

SYSTEM TRANSMISSION INTEGRATION AGREEMENT	The System Transmission Integration Agreement, dated June 15, 2000, is among Appalachian Power Company, Kentucky Power Company, Ohio Power Company, Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011), Indiana Michigan Power Company, and their agent AEPSC; and Public Service Company of Oklahoma, Southwestern Electric Power Company, Central Power and Light, now AEP Texas Central, West Texas Utilities, now AEP Texas North, and their agent CSWS (succeeded by AEPSC). This agreement provides the contractual basis for coordinated planning, operation and maintenance of the AEP East Zone and the AEP West Zone System Transmission Facilities to achieve economies consistent with the provision of reliable electric service and an equitable sharing of the benefits and costs of such coordinated arrangements.
TRANSMISSION AGREEMENT	The Transmission Agreement, dated April 1, 1984, is among Appalachian Power Company, Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011), Indiana Michigan Power Company, Kentucky Power Company, and Ohio Power Company (Members) and AEPSC (Agent). This agreement provides for the equitable sharing of costs incurred among the Members for their respective high-voltage and extra high-voltage transmission facilities. This agreement is administered by AEPSC.
AEP SYSTEM TRANSMISSION CENTER AGREEMENT	AEP SYSTEM TRANSMISSION AGREEMENT, dated December 1, 2009 between Ohio Power Company and the AEP West operating companies (AEP

	Texas Central Company, AEP Texas North Company, Public Service Company of Oklahoma, and Southwestern Electric Power Company). This agreement provides for the West Operating Companies to make use of the AEP Transmission Training Center facilities located in Pataskala, OH and owned by AEP Power for the training of transmission line personnel employed by the West Operating Companies.
TRANSMISSION COORDINATION AGREEMENT	This agreement, dated January 1, 1997 and revised October 29, 1999, is among Central Power and Light Company, West Texas Utilities Company, Public Service Company of Oklahoma, and Southwestern Electric Power Company. This agreement provides for the equitable sharing of costs incurred and revenues earned among the members for their respective transmission systems.
THIRD AMENDED AND RESTATED AGENCY AGREEMENT (ACCOUNTS RECEIVABLE)	This agreement, dated August 25, 2004 as amended March 22, 2006 and January 30, 2008, is among AEP Credit, Inc. and certain AEP electric companies. This agreement provides for the sale by the operating companies to AEP Credit, Inc. of accounts receivables arising from the sale and delivery of electricity, gas and other related services in the normal course of business.

AEP AMERICAN ELECTRIC POWER

Document Number **04-02-02**

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
SERVICE AGREEMENTS

THIRD AMENDED AND RESTATED PURCHASE AGREEMENT (ACCOUNTS RECEIVABLE)	This agreement, dated August 25, 2004 as amended March 22, 2006 and January 30, 2008 is among AEP Credit, Inc. and certain AEP electric companies. This agreement provides for the agent (Operating Companies) to take any and all steps on behalf of AEP Credit to collect all amounts due under any or all of the receivables arising from the sale and delivery of electricity, gas and other related services in the normal course of business.
ENERGY CONSERVATION MEASURE UTILITY/ENERGY SERVICE COMPANY AGENCY AGREEMENT	This agreement, dated December 22, 1997, is between West Texas Utilities, Inc. and EnerShop, Inc (EnerShop not longer exists). West Texas Utilities, Inc. (WTU) has signed an Energy Conservation Measures Agreement with the United States Government relating to the refurbishing and upgrading of US Government facilities located within the service territory of WTU. EnerShop is authorized as the agent for WTU in completing any Delivery/Task Orders agreed to by WTU and the US Government. These Orders are for energy conservation projects.
FRANKLIN AND INDIANA FRANKLIN PURCHASE CONTRACTS	Franklin Real Estate Company (Franklin) and Indiana Franklin Realty, Inc. (Indiana Franklin) have purchase contracts with AEP's electric utilities (various dates). The contracts provide that Franklin and Indiana Franklin (Sellers) may buy,sell,hold

	title to, or lease real estate as agents for the benefit of the respective electric utilities (i.e., each Purchaser).
INDIAN MESA INTERCONNECTION AGREEMENT	The Interconnection Agreements dated March 19, 2001, are between West Texas Utilities, now AEP Texas North and Indian Mesa Power Partners, LP (Generator). These two agreements provide for the interconnection of WTU, now AEP Texas North's transmission system to the Generator's electric generating facilities (Plant) built in two (2) phases. The interconnection of each phase of the Plant is provided by the separate agreements.
ELECTRIC TRANSMISSION TEXAS SERVICE AGREEMENT	This agreement, dated December 21, 2007 is between Electric Transmission Texas (ETT) and AEPSC. This agreement covers the provision of services by AEPSC for ETT related to (i)the evaluation and permitting of electric transmission projects by ETT; (ii) budgeting and scheduling services, the preparation of construction documents, land acquisition services, engineering services, procurement services, construction services, and the compilation of project records, relating to the construction of electric transmission projects by ETT; (iii) operation and maintenance of its electric transmission projects; (iv) legal, human resources, environmental services, payroll, cash management, financial, billing, collection, accounts-payable, risk management, regulatory affairs, accounting, tax, and other business functions.

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Affiliate Contracts with Regulated Companies

Subject
SERVICE AGREEMENTS

PATH WEST VIRGINIA TRANSMISSION COMPANY SERVICE AGREEMENT	This agreement, dated September 1, 2007 PATH) is between PATH West Virginia Transmission Company, LLC and AEP T&D Services, LLC. This agreement covers the provision of services by AEP T&D Services, LLC for PATH relating to designing, engineering, siting, acquiring right-of-way for procuring, permitting, construction, commissioning, financing, owning, operating, and maintaining certain electric transmission and interconnection facilities.

AEP AMERICAN ELECTRIC POWER

Document Number **04-02-03**

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies
Subject

MINING AND TRANSPORTATION

SUMMARY

AEP System affiliates acquire coal for and provide for transporting coal to AEP's regulated utilities. With respect to certain affiliated power plants, AEP System affiliates may provide coal mining, coal preparation and/or coal transloading services.

COAL MINING (including lignite)

The following table lists the mining agreements between AEP's electric utilities and their mining subsidiaries:

DATE	***PARTIES***
05-31-01	Southwestern Electric Power Company and Dolet Hills Lignite Company LLC.

This agreement provides that the above mentioned mining company agree to mine, extract, remove, prepare and sell the coal or lignite they mine from their lands and, in some cases, from lands owned by the electric utility. The electric utility, in turn, agrees to purchase the coal and lignite. Certain AEP mines have been closed but continue to incur mine shutdown costs.

COAL TRANSPORTATION

There are several contracts under which AEP's electric utilities receive coal transportation services from affiliates.

BARGE TRANSPORTATION

The Barge Transportation Agreement, dated May 1, 1986 and amended September 12, 2013, and amended May 9, 2019 is among Appalachian Power Company, Ohio Power Company, AEP Generating Company and Kentucky Power Company (Shippers) and the River Transportation Division of Indiana Michigan Power Company (Division).

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Section
Affiliate Contracts with Regulated Companies

Subject
MINING AND TRANSPORTATION

	This agreement provides for the Shippers to furnish and deliver coal to the Division at loading points along certain rivers and to accept delivery of such coal at designated delivery points and pay for the services of the Division in receiving, transporting and delivering such coal.
COAL TRANSFER-COOK COAL TERMINAL	The Amended and Restated Cook Coal Transfer Agreement – Cook Coal Terminal, dated December 16, 2013, is between AEP Generating Company (Operator) and Ohio Power Company, Indiana Michigan Power Company, Kentucky Power Company and Appalachian Power Company (Users). This agreement provides for the Operator to unload coal for the Users from unit trains, transfer such coal from the unloading point at the terminal, re-load such coal on barges, and perform other related services at the terminal.
RAIL CAR USE	The AEP System Rail Car Use Agreement, dated April 1, 1982, is among Indiana Michigan Power Company, Appalachian Power Company and Ohio Power Company. It was amended effective July 1, 2006 to add Public Service Company of Oklahoma and Southwestern Electric Power Company as parties to the agreement. It was amended again effective September 12, 2013 to add Kentucky Power Company as a party to the agreement. This agreement provides that coal hopper cars leased or otherwise deployed by the above parties be made available for the mutual benefit of each party without regard to lease ownership by a specific party but on the basis of proximity and availability

AEP AMERICAN ELECTRIC POWER

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Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
MINING AND TRANSPORTATION

for use, and other dispatching considerations.

RAILCAR MAINTENANCE

The Rail Car Maintenance Agreement, dated August 1, 2013, is among AEP Generating Company (Provider), Ohio Power Company, Appalachian Power Company, Kentucky Power Company, Public Service of Oklahoma Southwestern Electric Power Company and Indiana Michigan Power Company.

This agreement provides for AEP Generating Company to furnish routine, preventive and other maintenance to the railroad hopper cars owned or leased by Appalachian Power Company, Kentucky Power Company, Public Service of Oklahoma Southwestern Electric Power Company and Indiana Michigan Power Company.

The Rail Car Maintenance Facility Agreement, dated July 29, 1997, is among SWEPCO, CPL, now AEP Texas Central, PSO.

A unit train rail car maintenance facility near Alliance, Nebraska has been established. SWEPCO is the majority owner and operates the facility. The actual cost of inspection and maintenance of individual rail cars and other expenses directly assignable to a specific rail car shall be paid by the party owning the rail car. Non-assignable costs are shared based on the direct labor charges for rail cars actually repaired or inspected per party in ratio to the total direct labor charges for all cars owned by the parties repaired at the facility during the month.

AEP AMERICAN ELECTRIC POWER

Document Number **04-02-04**

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
CONSULTING SERVICES

SUMMARY

This document identifies the consulting services agreements AEP's regulated utilities have with certain non-regulated affiliates.

AEP PRO SERV, INC. formerly AEP Resources Service Company, AEP Resources Engineering & Services Company and AEP Energy Services, Inc.)

The following table lists the consulting agreements between the AEP electric utilities and AEP Pro Serv, Inc. referred to as the "Client". These agreements allow the Client to utilize certain services, properties and resources of the AEP electric utilities to sell management, technical and training services and expertise to non-affiliate companies.

DATE	***PARTIES***
04-08-1983	Indiana Michigan Power Company and AEP Pro Serv, Inc.
04-08-1983	Ohio Power Company and AEP Pro Serv, Inc.
07-07-1983	Kingsport Power Company and AEP Pro Serv, Inc.
07-07-1983	Kentucky Power Company and AEP Pro Serv, Inc.
10-03-1983	Appalachian Power Company and AEP Pro Serv, Inc.
10-03-1983	Wheeling Electric Company and AEP Pro Serv, Inc.

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Document Number **04-02-05**

Cost Allocation Manual

Section
Affiliated Contracts with Regulated Companies

Subject
JOINT OPERATING AGREEMENTS

SUMMARY

Certain other AEP facilities are jointly owned and/or operated.

PHILIP SPORN PLANT AGREEMENT

The Sporn Plant Operating Agreement, dated January 1, 2014, is between Appalachian Power Company and AEP Generation Resources Inc. ("Owners") and American Electric Power Service Corporation ("Agent").

Appalachian Power Company ("APCO")owns Sporn Unit Nos. 1 and 3) and AEP Generation Resources Inc. ("AEPGR")owns Sporn units 2, 4 and 5). The Sporn Plant retired in May 2015. Under the Agreement, APCO bills AEPGR for its share of the post-retirement costs that APCO incurs at Sporn Plant.

MITCHELL PLANT

The Mitchell Plant Operating Agreement, dated January 31, 2015, is between Kentucky Power Company and Wheeling Power Company ("Owners") and American Electric Power Service Corporation ("Agent").

Kentucky Power Company and Wheeling Power Company have an undivided ownership interest in Mitchell Plant which consists of two 800 megawatt generating units. The Owners desire that Kentucky Power Company operate and maintain Mitchell Plant.

AEP AMERICAN ELECTRIC POWER

Document Number **04-02-05**

Cost Allocation Manual

Section
Affiliated Contracts with Regulated Companies

Subject
JOINT OPERATING AGREEMENTS

EAST HVDC INTERCONNECTION AGREEMENT	This agreement, dated August 3, 1995, is among Southwestern Electric Power Company, CSW,now AEP Texas, Houston Lighting and Power Company (now Reliant Energy, HLP) and Texas Utilities Electric Company. This agreement covers certain high voltage direct current (HVDC) conversion and related alternating current transmission defined as the HVDC Interconnection located in Titus County. SWEPCO operates the facility. It owns certain of the alternating current facilities and charges the other partici-pants a facility charge based on their ownership interest in the HVDC Project. SWEPCO also bills operational and maintenance charges it incurs as the operator based on ownership interest.
OKLAUNION UNIT NO.1 CONSTRUCTION, OWNERSHIP AND OPERATING AGREEMENT (Also known as the Participation Agreement)	This agreement, dated April 26, 1985 (as amended on August 14, 1985) is among Public Service Company of Oklahoma, AEP Texas North, now AEP Texas, the Oklahoma Municipal Power Authority and the City of Brownsville, Texas. The Oklaunion Power Unit No. 1 is a 720 MW western coal fired steam generator. It is located on 1937.2 acres in Wilbarger County, Texas. This agreement is for the construction, ownership and operation of Oklaunion Power Unit 1.
OKLAUNION HVDC PROJECT CONSTRUCTION, OWNERSHIP AND OPERATING AGREEMENT	This agreement, dated September 14,1988, is among PSO, AEP Texas North Company now AEP Texas and Central and South West Services, Inc. PSO and TNC own, and PSO operates the project known as the Oklaunion HVDC Tie located in Wilbarger County, Texas.

AEP AMERICAN ELECTRIC POWER

Document Number **04-02-06**

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
TAX AGREEMENT

SUMMARY

American Electric Power Company, Inc. (AEP) joins in filing a consolidated federal income tax return with its affiliates in the AEP holding company system.

TAX AGREEMENT

The AEP System tax agreement, among other things, sets forth the companies' agreement to annually join in the filing of a consolidated federal income tax return and the method under which to allocate the consolidated tax to the system companies. This agreement permits the allocation of the benefit of current tax losses utilized to the System companies giving rise to them in determining their current tax expense.

The tax loss of AEP is allocated to its subsidiaries with taxable income. With the exception of the loss of AEP, the method of allocation approximates a separate return result for each company in the consolidated group.

AEP AMERICAN ELECTRIC POWER

Document Number **04-02-07**

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
AEP SYSTEM AMENDED AND RESTATED MONEY POOL AGREEMENT

SUMMARY

The AEP System Utility Money Pool Agreement is an arrangement whereby the participants in the Utility Money Pool lend to and borrow from each other on a short-term basis.

DESCRIPTION

The AEP System Amended and Restated Money Pool Agreement, dated November 3, 2017,is among and between AEP, American Electric Power Service Corporation, and AEP Utility Funding LLC and regulated direct and indirect operating and certain other subsidiaries each of which are signatories to the Agreement or have become signatories.

The Agreement gives participants the right to borrow from the pool and invest their excess funds in the pool.

A further description of the Utility Money Pool is contained in another section of this manual (see the Table of Contents or the Alphabetic Subject Index to find the applicable Document Number).

Date
February 22, 2018

AEP AMERICAN ELECTRIC POWER

Document Number **04-02-08**

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
AEP SYSTEM AMENDED AND RESTATED NONUTILITY MONEY POOL AGREEMENT

SUMMARY

The AEP System Nonutility Money Pool Agreement is an arrangement whereby the participants in the Nonutility Money Pool lend to and borrow from each other on a short-term basis.

DESCRIPTION OF THE AGREEMENT

The AEP System Fourth Amended and Restated Nonutility Money Pool Agreement, dated May 1, 2012, is between AEP, and American Electric Power Service Corp., AEP Nonutility Funding LLC certain and unregulated direct and indirect subsidiaries of AEP each of which are signatories to the Agreement or have become signatories.

The Agreement gives each pool participant the right to borrow from the pool and to invest excess funds in the pool.

A further description of the Nonutility Money Pool is contained in another section of this manual (see the Table of Contents or the Alphabetic Subject Index to find the applicable Document Number).

AEP AMERICAN ELECTRIC POWER

Document Number **04-03-01**

Cost Allocation Manual

Section

Databases

Subject

OVERVIEW

SUMMARY — Certain databases have been established for employee reference purposes.

CHARTFIELD VALUES — A separate database can be used to view certain chartfield values. The chartfield database contains the most current information regarding the various chartfield values and descriptions.

04-03-02

AFFLIATE AGREEMENTS — Copies of all agreements between AEP regulated utilities and their affiliates are kept in Company files.

04-03-03

AEP AMERICAN ELECTRIC POWER

Document Number **04-03-02**

Cost Allocation Manual

Section

Databases

Subject

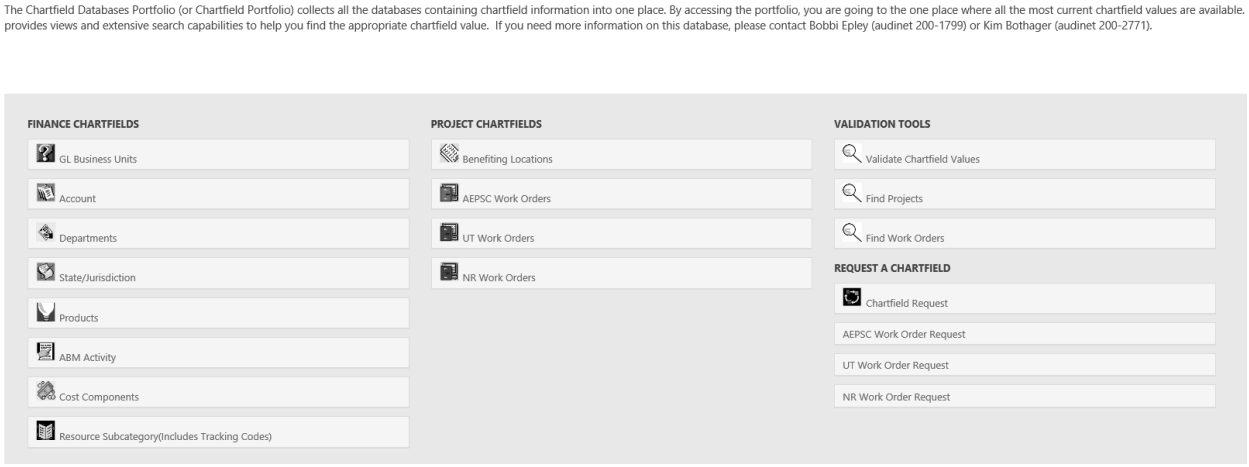
CHARTFIELD VALUES

SUMMARY

Several chartfield databases have been established for employee reference purposes. A web link provides a menu for accessing the separate databases and tools. The chartfield databases contain the most current information regarding the various chartfield values and descriptions and links to the same information regarding work orders.

INSTRUCTIONS FOR VIEWING

https://sharenow2.sp.aepsc.com/shsvcs/cfieldport/SitePages/ChartFieldHome.aspx



AEP AMERICAN ELECTRIC POWER

Document Number **04-03-03**

Cost Allocation Manual

Section

Databases

Subject

AFFILIATE AGREEMENTS

SUMMARY

An affiliated contracts Sharepoint site exists for reference purposes. A SharePoint web-link provides a method for accessing this information. The affiliated contracts Sharepoint site contains copies of the affiliated contracts.

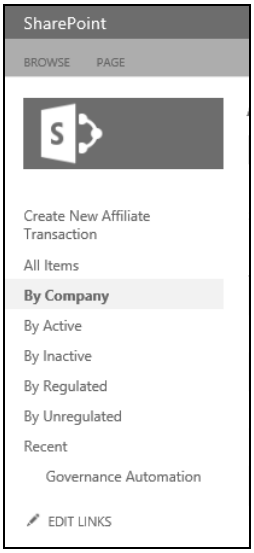
INSTRUCTIONS FOR ACCESSING SHAREPOINT

Enter the below address into web browser:

https://sharenow2.sp.aepsc.com/shsvcs/ACA/SitePages/Home.aspx

INSTRUCTIONS FOR VIEWING

To view the appropriate affiliate contract, use the category groups on the left panel and click on the name of the contract.



SECURITY ACCESS

The CAM Administrator grants access to the affiliated contracts SharePoint site on an as needed basis.

AEP AMERICAN ELECTRIC POWER

Document Number **04-04-01**

Cost Allocation Manual

Section

Job Descriptions

Subject

OVERVIEW

SUMMARY

The corporate separation rules adopted by the Public Utilities Commission of Ohio (PUCO) require the electric utility, as defined in the rules, to maintain a copy of each shared employee's job description in its Cost Allocation Manual (CAM). In addition, the CAM shall include a copy of all transferred employees' previous and new job descriptions.

The corporate separation rules define "employees" as "all full-time or part-time employees of an electric utility or its affiliates, as well as consultants, independent contractors or any other persons, performing various duties or obligations on behalf of or for an electric utility or its affiliates."

Job descriptions are not required, nor are they maintained, for consultants, independent contractors or any other persons who are not actual employees of the electric utility or its AEP affiliates.

SHARED EMPLOYEES

Job descriptions for all employees who are shared between AEP's PUCO regulated electric utilities and any affiliate that provides a competitive retail electric service, or that provides a non-electric product or service to customers, are incorporated in this manual by reference.

04-04-02

AEP AMERICAN ELECTRIC POWER

Document Number **04-04-01**

Cost Allocation Manual

Section

Job Descriptions

Subject

OVERVIEW

TRANSFERRED EMPLOYEES

The required previous and current job descriptions for employees transferred from AEP's PUCO regulated electric utilities to any affiliate that provides a competitive retail electric service, or that provides a non-electric product or service to customers, are incorporated in this manual by reference.

O4-04-03

AEP AMERICAN ELECTRIC POWER

Document Number **04-04-02**

Cost Allocation Manual

Section

Job Descriptions

Subject

SHARED EMPLOYEES (PUCO)

SUMMARY

4901:1-37-04 (A)(4) of the Public Utilities Commission of Ohio's (PUCO's) corporate separation rules states that an electric utility may not share employees and/or facilities with any affiliate, if the sharing, in any way, violates the code of conduct provisions contained in its corporate separation rules.
In addition, 4901:1-37-08 (D)(4) and 4901:1-37-04 (A) (5) of the corporate separation rules require the electric utility to maintain a copy of each shared employee's job description in its Cost Allocation Manual and to ensure that all shared employees appropriately record and charge their time based on fully allocated costs.

DEFINITION OF SHARED EMPLOYEE

In the corporate separation plans filed by Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011) (Case No. 99-1730-EL-ETP), the respondents defined a "shared employee" as:

> *Any employee of the electric utility, or any affiliate which provides a competitive retail electric service or which provides a non-electric product or service to customers (i.e., the Separate AEP Companies), or a consultant, independent contractor, or any other person performing various duties or obligations on behalf of the electric utility or the Separate AEP Companies, whose more than incidental job duties and responsibilities are divided between the electric utility and any Separate AEP Companies for other than emergency purposes.*

AEP AMERICAN ELECTRIC POWER

Document Number **04-04-02**

Cost Allocation Manual

Section

Job Descriptions

Subject

SHARED EMPLOYEES (PUCO)

PROCEDURE

For purposes of this manual,job descriptions for shared employees who are true employees of the electric utility or any Separate AEP Company are included in this manual by reference and, as such, are part of this manual.

Job descriptions are not maintained for consultants, independent contractors or other persons who are shared but are not actual employees of the electric utility or the Separate AEP Companies. However, a list of such persons will be maintained. The list will identify the name of each such person and the name of the person's actual employer. The list, which will be prepared at least every six months, is incorporated in this manual by reference and, as such, is part of this manual.

RESPONSIBILITY

AEP Service Corporation's Human Resources Department, working with AEP's various business units, will prepare, on behalf of AEP's PUCO regulated electric utilities, the required job descriptions for all shared employees; and it will also maintain the required list of other shared persons who are not actual employees.

AEP AMERICAN ELECTRIC POWER

Document Number **04-04-02**

Cost Allocation Manual

Section

Job Descriptions

Subject

SHARED EMPLOYEES (PUCO)

TIME CHARGES

AEP's time reporting systems are designed to ensure that salary and salary-related costs are properly allocated by requiring employees, using positive time reporting, to charge their time to the appropriate accounting codes. All time charges are allocated and billed on a fully allocated cost basis as defined in the PUCO's Corporate Separation rules.

[NOTE: Other state commissions have established requirements relative to shared employees. See TAB 02, Section 04 of this manual for further information.]

AEP AMERICAN ELECTRIC POWER

Document Number **04-04-03**

Cost Allocation Manual

Section

Job Descriptions

Subject

TRANSFERRED EMPLOYEES (PUCO)

SUMMARY

4901:1-37-08 (D)(6) of the Public Utilities Commission of Ohio's (PUCO's) corporate separation rules require electric utilities, as defined in the rules, to add to their Cost Allocation Manuals (CAMs) a copy of all transferred employees' previous and new job descriptions.

DEFINITION OF TRANSFERRED EMPLOYEE

A "transferred employee" is any full-time or part-time employee of the electric utility, as well as any consultant, independent contractor or any other person, who performs various duties or obligations for or on behalf of the electric utility, that transfers from the electric utility to any affiliate which provides a competitive retail electric service or which provides a non-electric product or service to customers (i.e., the Separate AEP Companies).

PROCEDURE

For purposes of this manual, previous and new job descriptions for all true employees of the electric utility that transfer to a Separate AEP Company are included in this manual by reference and, as such, are part of this manual.

Job descriptions are not maintained for consultants, independent contractors or other persons who are not true employees of the AEP System. However, a list of all such persons who transfer from the electric utility to a Separate AEP Company will be maintained. The list will identify the name of each such person and the name of the person's actual employer. The list, which will be prepared at least every six months, is incorporated in this manual by reference and, as such, is part of this manual.

AEP AMERICAN ELECTRIC POWER

Document Number **04-04-03**

Cost Allocation Manual

Section

Job Descriptions

Subject

TRANSFERRED EMPLOYEES (PUCO)

RESPONSIBILITY

AEP Service Corporation's Human Resources Department, working with AEP's various business units, will prepare, on behalf of any AEP electric utility regulated by the PUCO, the required job descriptions for all employees who transfer from the electric utility to a Separate AEP company. A list of all such persons who transfer from the electric utility to a separate AEP Company will be maintained electronically. Information stored will include the name of each such person and the name of the person's actual employer. The list, which can be prepared at any time upon request, is incorporated in this manual by reference and, as such, is part of this manual. Human Resources will also maintain the required list of other transferred persons who are not actual employees of the AEP System.

[NOTE: Other state commissions have established requirements relative to transferred employees. See TAB 02, Section 04 of this manual for further information.]

AEP AMERICAN ELECTRIC POWER

Document Number **04-05-01**

Cost Allocation Manual

Section

Complaint Log

Subject

OVERVIEW

SUMMARY

The corporate separation rules adopted by the Public Utilities Commission of Ohio require Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011) to establish a complaint procedure for issues related to their respective corporate separation plans.

COMPLAINT LOG

A log of complaints brought to the electric utility must be maintained as part of the electric utility's Cost Allocation Manual.

04-05-02

AEP AMERICAN ELECTRIC POWER

Document Number **04-05-02**

Cost Allocation Manual

Section

Complaint Log

Subject

CORPORATE SEPARATION (PUCO)

SUMMARY	4901:1-37-05 (B) (14) and 4901:1-37-08 (D)(8) of the Public Utilities Commission of Ohio's (the PUCO's) corporate separation rules require the electric utilities, as defined in the rules, to establish a complaint procedure for issues concerning compliance with the PUCO's corporate separation rules and a log of complaints brought to the utility to be included in its CAM.
RESPONSIBILITY	AEP's Chief Compliance Officer will follow the procedures for handling such complaints as set forth in the PUCO's rules and as stated in the corporate separation plans filed by Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011) and Ohio Power Company.
CAM REQUIREMENTS	The required complaint log is incorporated in this manual by reference and, as such, is part of this manual.

AEP AMERICAN ELECTRIC POWER

Document Number **04-06-01**

Cost Allocation Manual

Section

Board of Directors Minutes

Subject

OVERVIEW

SUMMARY

The corporate separation rules adopted by the Public Utilities Commission of Ohio (PUCO)
require Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011), or any successor electric utility company operating in the state of Ohio, to incorporate a copy of the minutes of each of their board of directors meetings in their Cost Allocation Manual (CAM).

COPIES

The required minutes are incorporated in this manual by reference.

04-06-02

AEP AMERICAN ELECTRIC POWER

Document Number **04-06-02**

Cost Allocation Manual

Section

Board of Directors Minutes

Subject

COPIES (PUCO)

SUMMARY	4901:1-37-08(D)(9) of the PUCO's corporate separation rules require electric utilities to incorporate their minutes of each board of directors meeting in their Cost Allocation Manual (CAM) as a structural safeguard for a minimum period of three years.
RESPONSIBILITY	AEP's Legal Department maintains the required minutes as described in the corporate separation plans filed by Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011) and Ohio Power Company.
CAM REQUIREMENTS	The required minutes are incorporated in this manual by reference and, as such, are part of this manual.

AEP AMERICAN ELECTRIC POWER

Document Number **04-07-01**

Cost Allocation Manual

Section

Tariff Provisions

Subject

Overview

SUMMARY	The corporate separation rules adopted by the Public Utilities Commission of Ohio requires Ohio Power Company to establish a procedure detailing each instance in which the electric utility exercised discretion in the application of its tariff provisions.
TARIFF DISCRETION LOG	A log detailing each instance when the electric utility exercised discretion in application of its tariff provisions must be maintained as part of the electric utility's Cost Allocation Manual.

AEP AMERICAN ELECTRIC POWER

Document Number **04-07-02**

Cost Allocation Manual

Section

Tariff Provisions

Subject

SUMMARY	4901:1-37-08 (D) (7) of the Public Utilities Commission of Ohio's (the PUCO's) corporate separation rules require the electric utilities, as defined in the rules, to establish a procedure detailing each instance in which the electric utility exercised discretion in the application of its tariff provisions and a log of such instances to be included in its CAM.
RESPONSIBILITY	AEP Ohio's VP of Regulatory and Finance maintains the required procedure and related Tariff Discretion Log.
CAM REQUIREMENTS	The required log is incorporated in this manual by reference and, as such, is part of this manual.

AEP AMERICAN ELECTRIC POWER

Document Number **99-00-01**

Cost Allocation Manual

Section

Appendix

Subject

OVERVIEW (APPENDIX)

SUMMARY

This appendix contains tables and other supplementary information that can be used for reference purposes.

GLOSSARY OF KEY TERMS

A glossary of key terms and acronyms is provided to assist the reader.

99-00-02

RECORD RETENTION REQUIREMENTS

A summary of the record retention requirements prescribed by AEP's various commissions for transactions with affiliates is maintained as part of this manual.

99-00-03

LIST OF APPROVED ALLOCATION FACTORS

An Allocation Factor defines the factor(s) that will be used to derive the percentages of cost to be billed to each company whenever costs are shared among AEP System companies through the billing process.

A list of approved Allocation Factors is maintained as part of this manual.

99-00-04

LIST OF PRIMARY ALLOCATION FACTORS BY FUNCTION

Allocation Factors are assigned to final cost objectives generally based on the nature (i.e., function) of the work performed.

A list of the primary Allocation Factors for each function is maintained as part of this manual.

99-00-05

LIST OF AFFILIATE

AEP's regulated utilities have entered into

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OVERVIEW (APPENDIX)

CONTRACTS BY COMPANY

LIST OF AFFILIATE CONTRACTS BY COMPANY (Cont'd)

various agreements with their affiliates. **TAB** 04, Section 02 of this manual contains a description of each contract.

A list of the various contracts with each regulated utility is maintained as part of this manual.

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GLOSSARY OF KEY TERMS

SUMMARY

This glossary provides definitions for key terms and abbreviations used in this manual. Unless the context in which the terms and abbreviations as used in this manual clearly indicate a different meaning as indicated in this glossary

AEP	American Electric Power Company, Inc.
AEPSC	American Electric Power Service Corporation
AEP holding company system	American Electric Power Company, Inc. (parent holding company) together with all of its subsidiaries.
AEP System	The electric utility companies, subsidiaries of American Electric Power Company, Inc. together with their subsidiary coal-mining and power generating companies as well as AEPSC.
Affiliates	While each regulatory commission has its own unique definition of the term "affiliates," as used in this manual the term generally includes American Electric Power Company, Inc. and all companies that are owned or controlled by American Electric Power Company, Inc.
Affiliate transactions	Transactions between or among affiliates for the sale and purchase of products, services and capital assets.
Allocation Factors	The cost allocation methods, factors and percentages used in the billing process to allocate costs among AEP companies.

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GLOSSARY OF KEY TERMS

Chartfields (or coding blocks)	The distinctive fields used to affix codes to transaction records generally for the purpose of identification, classification and retrieval.
Common costs	Costs that benefit both regulated and non-regulated products and services. Also see, **Joint costs.**
Cost allocator	The method or ratio used to apportion cost. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).
Cost driver	A measurable event or quantity which influences the level of cost incurred and which can be directly traced to the origin of the costs themselves.
Primary cost driver	The dominant driver of a given cost or cost pool.
Cross-subsidy	The amount of cost recovered from one class of customers or business unit that is attributable to another.
Direct costs	Costs that can be identified specifically with a given cost objective.
FERC	Federal Energy Regulatory Commission.
Fully-allocated costs (or fully-distributed	Direct costs plus an appropriate share of indirect costs attributed to a given cost

costs)	objective.
General allocator	See **Cost allocator.**
Indirect costs	Costs that cannot be identified specifically with a given cost objective. Indirect costs include, but are not limited to overhead costs, and some taxes.
Joint costs	Costs that benefit two or more cost objectives.
Non-regulated operations	Activities which produce products or services that are not subject to price regulation by regulatory authorities.
Regulated operations	Activities which produce products or services that are subject to price regulation by government authorities.
SEC	Securities and Exchange Commission.
Shareable costs	Costs that are billable to two or more companies (affiliated and non-affiliated) by mutual agreement using fixed or variable percentages.
Transfer pricing	The price or method used to transfer (or bill for) products or services delivered by one division of a company to another division, or by one affiliate to another affiliate. Transfer pricing also pertains to asset transfers and sales.

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GLOSSARY OF KEY TERMS

USoA The Uniform System of Accounts adopted by each regulatory commission (usually the Uniform System of Accounts prescribed by the FERC for public utilities and licensees subject to the provisions of the Federal Power Act).

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RECORD RETENTION REQUIREMENTS

SUMMARY

Some of AEP's commissions have prescribed minimum record retention requirements for those records that are specifically related to transactions with certain affiliates.

ARKANSAS

Arkansas Rule 4.04 requires an electric utility to maintain a record of all transactions with its competitive affiliates for at least three years following the date of each transaction.

Arkansas requirements can be found in Arkansas Public Service Commission Order 7 of Docket 06-112-R, dated May 25, 2007.

LOUISIANA

As prescribed in the Louisiana Merger Stipulation Appendix A – Affiliate Transaction Conditions 13, SWEPCO or AEPSC on behalf of SWEPCO may not make any non-emergency procurement in excess of $1 million per transaction from an unregulated affiliate other than from AEPSC except through a competitive bidding process or as otherwise authorized by this Commission. Transactions involving the Company and CSW Credit, Inc. (or its successor) for the financing of accounts receivables are exempt from this condition. Records of all such affiliate transactions must be maintained until the Company's next comprehensive retail review. In addition, at the time of the next comprehensive rate review, all such affiliate transactions that were not competitively bid shall be separately identified for the Commission by the Company. This identification shall include all transactions between the Company and AEPSC in which AEPSC acquired the goods or services from another unregulated affiliate.

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RECORD RETENTION REQUIREMENTS

OHIO	The corporate separation rules adopted by the Public Utilities Commission of Ohio (PUCO) contain a minimum retention period of three years for all information relative to transactions between the electric utility and its affiliates [4901:1-37-08(G]. As prescribed by the PUCO, all of AEP's Ohio-based electric utilities and their affiliates shall maintain all underlying affiliate transaction information for a minimum of five years.
OKLAHOMA	The Oklahoma Corporation Commission rules require utility to keep records in the form and for a period of time not less than that specified by the applicable rules of FERC or the RUS; or in the absence thereof, for two (2) years. [Chapter 165:35-1-4(a)].
TEXAS	Transactions with competitive affiliates. Unless otherwise allowed in this subsection, transactions between a utility and its competitive affiliates shall be at arm's length. A utility shall maintain a contemporaneous written record of all transactions with its competitive affiliates, except those involving corporate support services and those transactions governed by tariffs. Such records, which shall include the date of the transaction, name of affiliate involved, name of a utility employee knowledgeable about the transaction, and a description of the transaction, shall be maintained by the utility for three years. In addition to the requirements specified in paragraph (1) of this subsection, the

following provisions apply to transactions between utilities and their competitive affiliates. [§25.272(e)(2)].

TEXAS (Cont'd)

Discounts, rebates, fee waivers, or alternative tariff terms and conditions. If a utility offers its competitive affiliate or grants a request from its competitive affiliate for a discount, rebate, fee waiver, or alternative tariff terms and conditions for any product or service, it must make the same benefit contemporaneously available, on a non-discriminatory basis, to all similarly situated non-affiliates. The utility shall post a conspicuous notice on its Internet site or public electronic bulletin board for at least 30 consecutive calendar days providing the following information: the name of the competitive affiliate involved in the transaction; the rate charged; the normal rate or tariff condition; the period for which the benefit applies; the quantities and the delivery points involved in the transaction (if any); any conditions or requirements applicable to the benefit; documentation of any cost differential underlying the benefit; and the procedures by which non-affiliates may obtain the same benefit. The utility shall maintain records of such information for a minimum of three years, and shall make such records available for third party review within 72 hours of a written request, or at a time mutually agreeable to the utility and the third party. A utility shall not create any arrangement with its competitive affiliate

that is so unique that no competitor could be similarly situated to benefit from the discount, rebate, fee waiver, or alternative tariff terms and conditions. [§25.272(f)(B)].

A competitive affiliate is an affiliate that provides services or sells products in a competitive energy-related market in Texas, including telecommunications services; to the extent those services are energy-related.

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LIST OF FERC ACCEPTED ALLOCATION FACTORS

SUMMARY

The following table provides a complete list of approved Allocation Factors along with a description of the numerator and the denominator applicable to each calculation.

NO.	ALLOCATION FACTORS	NUMERATOR/DENOMINATOR	UPDATED Frequency	Month Updated
01	Number of Bank Accounts	Number of Bank Accounts by Company Total Number of Bank Accounts	Inactive	
02	Number of Call Center Telephones	Number of Call Center Phone Calls Per Company Total Number of Call Center Telephones	Inactive	
03	Number of Cell Phones/Pagers	Number of Cell Phones/Pagers Per Company Total Number of Cell Phones/Pagers	Inactive	
04	Number of Checks Printed	Number of Checks Printed Per Company Per Month Total Number of Checks Printed Per Month	Inactive	
05	Number of CIS Customer Mailings	Number of Customer Information System (CIS) Customer Mailings Per Company Total Number of CIS Customer Mailings	Monthly	
06	Number of Commercial Customers	Number of Commercial Customers Per Company Total Number of Commercial Customers	Semi-Annually	Jan & Jul
07	Number of Credit Cards	Number of Credit Cards Per Company Total Number of Credit Cards Number of Commercial	Inactive	
08	Number of Electric Retail Customers	Number of Electric Retail Customers Per Company Total Number of Electric Retail Customers	Semi-Annually	Jan & Jul
09	Number of Employees	Number of Full-Time and Part-Time Employees Per Company Total Number of Full-Time and Part-Time Employees	Monthly	
10	Number of Generating Plant Employees	Number of Generating Plant Employees Per Company Total Number of Generating Plant Employees	Inactive	
11	Number of General Ledger(GL) Transactions	Number of GL Transactions Per Company Total Number of GL Transactions	Monthly	

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NO.	ALLOCATION FACTORS	NUMERATOR/DENOMINATOR	UPDATED Frequency	Month Updated
12	Number of Help Desk Calls	Number of Help Desk Calls Per Company Total Number of Help Desk Calls	Inactive	
13	Number of Industrial Customers	Number of Industrial Customers Per Company Total Number of Industrial Customers	Semi-Annually	Jan & Jul
14	Number of JCA Transactions	Number of Lines of Accounting Distribution on Job Cost Accounting (JCA) Sub-System Per Company Total Number of Lines of Accounting Distribution on JCA Sub-System	Inactive	
15	Number of Non-UMWA Employees	Number of Non-UMWA or All Non-Union Employees Per Company Total Number of Non-UMWA or All Non-Union Employees	Inactive	
16	Number of Phone Center Calls	Number of Phone Calls Per Phone Center Per Company Total Number of Phone Center Phone Calls	Monthly	
17	Number of Purchase Orders Written	Number of Purchase Orders Written Per Company Total Number of Purchase Orders Written	Monthly	
18	Number of Radios (Base/Mobile/Handheld)	Number of Radios (Base/Mobile/Handheld) Per Company Total Number of Radios (Base/Mobile/ Handheld)	Inactive	
19	Number of Railcars	Number of Railcars Per Company Total Number of Railcars	Inactive	
20	Number of Remittance Items	Number of Electric Bill Payments Processed Per Company Per Month (non-lockbox) Total Number of Electric Bill Payments Processed Per Month (non-lockbox)	Monthly	
21	Number of Remote Terminal Units	Number of Remote Terminal Units Per Company Total Number of Remote Terminal Units	Inactive	
22	Number of Rented Water Heaters	Number of Rented Water Heaters Per Company Total Number of Rented Water Heaters	Inactive	
23	Number of Residential Customers	Number of Residential Customers Per Company Total Number of Residential Customers	Inactive	

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NO.	ALLOCATION FACTORS	NUMERATOR/DENOMINATOR	UPDATED Frequency	Month Updated
24	Number of Routers	Number or Routers Per Company Total Number of Routers	Inactive	
25	Number of Servers	Number of Servers Per Company Total Number of Servers	Inactive	
26	Number of Stores Transactions	Number of Stores Transactions Per Company Total Number of Stores Transactions	Monthly	
27	Number of Telephones	Number of Telephones Per Company (Includes all phone lines) Total Number of Telephones (Includes all phone lines)	Semi-Annually	Jan & Jul
28	Number of Transmission Pole Miles	Number of Transmission Pole Miles Per Company Total Number of Transmission Pole Miles	Annually	Apr or May (FERC Form)
29	Number of Transtext Customers	Number of Expected Transtext Customers Per Company Total Number of Expected Transtext Customers	Inactive	
30	Number of Travel Transactions	Number of Travel Transactions Per Company Per Month Total Number of Travel Transactions Per Month	Inactive	
31	Number of Vehicles	Number of Vehicles Per Company Includes Fleet and Pool Cars) Total Number of Vehicles Per Company (Includes Fleet and Pool Cars)	Annually	Jan
32	Number of Vendor Invoice Payments	Number of Vendor Invoice Payments Per Company Per Month Total Number of Vendor Invoice Payments Per Month	Monthly	
33	Number of Workstations	Number of Workstations (PCs) Per Company Total Number of Workstations (PCs)	Monthly	
34	Active Owned or Leased Communication Channels	Number of Active Owned/Leased Communication Channels Per Company Total Number of Active Owned/Leased Communication Channels	Inactive	
35	Avg Peak Load For Past Three Years	Average Peak Load for Past Three Years Per Company Total of Average Peak Load for Past Three Years	Inactive	

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NO.	ALLOCATION FACTORS	NUMERATOR/DENOMINATOR	UPDATED Frequency	Month Updated
36	Coal Company Combination	The Sum of Each Coal Company's Gross Payroll, Original Cost of Fixed Assets, Original Cost of Leased Assets, and Gross Revenues for Last Twelve Months / The Sum of the Same Factors for All Coal Companies	Inactive	
37	AEPSC Past 3 Months Total Bill Dollars	AEPSC Past Three Months Total Bill Dollars Per Company / Total AEPSC Past Three Months Bill Dollars	Monthly	
38	AEPSC Prior Month Total Bill Dollars	Total Bill Dollars AEPSC Prior Month Per Company / AEPSC Total Prior Month Bill Dollars	Inactive	
39	Direct	100% to One Company	Monthly	
40	Equal Share Ratio	One Company (1) / Total Number of Companies	Monthly	
41	Fossil Plant Combination	The Sum of (a) the Percentage Derived by Dividing the Total Megawatt Capability of All Fossil Generating Plants Per Company by the Total Megawatt Capability of All Fossil Generating Plants and (b) the Percentage Derived by Dividing the Total Scheduled Maintenance Outages of All Fossil Generating Plants Per Company for the Last Three Years by the total Scheduled Maintenance of All Fossil Generating Plants During the Same Three Years / Two (2)	Inactive	
42	Functional Department's Past 3 Months Total Bill Dollars	Functional Department's Past 3 Months Total Bill Dollars Per Company / Total Functional Department's Past 3 Months Total Bill Dollars	Inactive	
43	KWH Sales	KWH Sales Per Company / Total KWH Sales	Inactive	

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NO.	ALLOCATION FACTORS	NUMERATOR/DENOMINATOR	UPDATED Frequency	Month Updated
44	Level of Construction – Distribution	Construction Expenditures for All Distribution Plant Accounts Except Land and Land Rights, Services, Meters and Leased Property on Customers Premises, and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC Are Being Made Separately, Per Company/During the Last Twelve Months Total of the Same for All Companies	Semi-Annually	Jan & Jul
45	Level of Construction - Production	Construction Expenditures for All Production Plant Accounts Except Land and Land Rights, Nuclear Accounts, and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC are Being Made Separately, Per Company During the Last Twelve Months Total of the Same for All Companies	Semi-Annually	Jan & Jul
46	Level of Construction – Transmission	Construction Expenditures for All Transmission Plant Accounts Except Land and Land Rights and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC are Being Made Separately, Per Company During the Last Three Months Total of the Same for All Companies	Quarterly	Jan – Apr – Jul - Oct
47	Level of Construction – Total	Construction Expenditures for All Plant Accounts Except Land and Land Rights, Line Transformers Services, Meters and Leased Property on Customers' premises; and the Following General Plant Accounts: Structures and Improvements, Shop Equipment, Laboratory Equipment and Communication Equipment; and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC are Being Made Separately, Per Company During the Last Twelve Months Total of the Same for All Companies	Inactive	
48	MW Generating Capability	MW Generating Capability Per Company Total MW Generating Capability	Annually	Apr or May (FERC Form)
49	MWH's Generated	Number of MWH's Generated Per Company Total Number of MWH's Generated	Semi-Annually	Jan & Jul

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NO.	ALLOCATION FACTORS	NUMERATOR/DENOMINATOR	UPDATED Frequency	Month Updated
50	Current Year Budgeted Salary Dollars	Current Year Budgeted AEPSC Payroll Dollars Billed Per Company Total Current Year Budgeted AEPSC Payroll Dollars Billed	Inactive	
51	Past 3 Mo. MMBTU's Burned (All Fuel Types)	Past Three Months MMBTU's Burned Per Company (All Fuel Types) Total Past Three Months MMBTU's Burned (All Fuel Types)	Quarterly	Jan – Apr – Jul – Oct
52	Past 3 Mo. MMBTU's Burned (Coal Only)	Past Three Months MMBTU's Burned Per Company (Coal Only) Total Past Three Months MMBTU's Burned (Coal Only)	Quarterly	Jan – Apr – Jul – Oct
53	Past 3 Mo. MMBTU's Burned (Gas Type Only)	Past Three Months MMBTU's Burned Per Company (Gas Type Only) Total Past Three Months MMBTU's Burned (Gas Type Only)	Quarterly	Jan – Apr – Jul – Oct
54	Past 3 Mo. MMBTU's Burned (Oil Type Only)	Past Three Months MMBTU's Burned Per Company (Oil Type Only) Total Past Three Months MMBTU's Burned (Oil Type Only)	Inactive	
55	Past 3 Mo. MMBTU's Burned (Solid Fuels Only)	Past Three Months MMBTU's Burned Per Company (Solid Fuels Only Total Past Three Months MMBTU's Burned (Solid Fuels Only)	Quarterly	Jan – Apr – Jul – Oct
56	Peak Load/Avg # Cust/KWH Sales Combination	Average of Peak Load, # of Retail Customers, and KWH Sales to Retail Customers Per Company Total of Average of Peak Load, # of Retail Customers, and KWH Sales to Retail Customers	Inactive	
57	Tons of Fuel Acquired	Number of Tons of Fuel Acquired Per Company Total Number of Tons of Fuel Acquired	Semi-Annually	Jan & Jul
58	Total Assets	Total Assets Amount Per Company Total Assets Amount	Monthly	
59	Total Assets Less Nuclear Plant	Total Assets Amount Less Nuclear Assets Per Company Total Assets Amount Less Nuclear Assets	Inactive	

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NO.	ALLOCATION FACTORS	NUMERATOR/DENOMINATOR	UPDATED Frequency	Month Updated
60	Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or Other Indirect Costs	Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or Other Indirect Costs Per Company Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or Other Indirect Costs	Annually	
61	Total Fixed Assets	Total Fixed Assets Amount Per Company Total Fixed Assets Amount	Monthly	
62	Total Gross Revenue	Total Gross Revenue Last Twelve Months Per Company Total Gross Revenue Last Twelve Months	Inactive	
63	Total Gross Utility Plant (Including CWIP)	Total Gross Utility Plant Amount Per Company (Including CWIP) Total Gross Utility Plant Amount (Including CWIP)	Monthly	
64	Total Peak Load	Total Peak Load Per Company Total Peak Load	Monthly	
65	Hydro MW Generating Capability	Hydro MW Generating Capability per Company Total Hydro MW Generating Capability	Annually	Apr or May (FERC Form)
66	Number of Forest Acres	Number of Forest Acres Per Company Total Number of Forest Acres	Inactive	
67	Number of Banking Transactions	Number of Banking Transactions Per Company Total Number of Banking Transactions	Quarterly	Jan – Apr – Jul – Oct
68	Number of Dams	Number of Dams Per Company Total Number of Dams	Inactive	
69	Number of Licenses Obtained	Number of Licenses Obtained per Company Total Number of Licenses	Inactive	
70	Number of Non-Electric OAR Invoices	Number of Non-Electric OAR Invoices Per Company Total Number of Non-Electric OAR Invoices	Semi-Annually	Jan & Jul
71	Number of Transformer Transactions	Number of Transformer Transactions Per Company Total Number of Transformer Transactions	Inactive	

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NO.	ALLOCATION FACTORS	NUMERATOR/DENOMINATOR	UPDATED Frequency	Month Updated
72	Tons of FGD Material	Tons of FGD Material Per Company Total Tons of FGD Material	Inactive	
73	Tons of Limestone Received	Tons of Limestone Received Per Company Total Tons of Limestone Received	Inactive	
74	Total Assets/Total Revenues/Total Payroll	Total Assets + Total Revenues + Total Payroll Per Company Total Assets + Total Revenues + Total Payroll	Inactive	
75	Total Leased Assets	Total Leased Assets Per Company Total Leased Assets	Inactive	
76	Number of Banking Transactions	Number of Banking Transactions by Company Total Number of Banking Transactions	Inactive	
77	Power Transactions to All Markets	Power Transactions by Company Total Number of Power Transactions	Inactive	
78	Power Transactions to ERCOT Market	Power Transactions to ERCOT Market by Company Total Number of Power Transactions to ERCOT Market	Inactive	
79	Trans (commdts) to All Markets	Trans (commdts) to all Markets by Company Total Number of Trans (commdts) to all Markets	Inactive	
80	Trans (commdts) to ERCOT Market	Trans (commdts) to ERCOT Markets by Company Total Number of Trans (commdts) to ERCOT Markets	Inactive	

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LIST OF PRIMARY ALLOCATION FACTORS BY FUNCTION

SUMMARY

The following table identifies the primary Allocation Factors that are associated with the listed functions.

GROUP/FUNCTION	***PRIMARY ALLOCATION FACTORS***
Audit Services	Total Assets, 100% to One Company
Chief Administrative Officer Administration	Total Assets
Chief Executive Officer Administration	Total Assets, 100% to One Company
Chief Security Officer Administration	Total Assets, Number of Employees
Chief Financial Officer Administration	Total Assets, 100% to One Company
Commercial Operations	Total Peak Load, 100% to One Company
Corporate Accounting	Total Assets, 100% to One Company, Number of GL Transactions, Total Fixed Assets, Total Gross Utility Plant
Corporate Communications	Total Assets
Corporate Human Resources	Number of Employees, 100% to One Company, AEPSC Past 3 Month Total Bill
Corporate Planning and Budgeting	Total Assets, 100% to One Company, Number of Electric Retail Customers, MW Generating Capability
Customer & Distribution Services	100% to One Company, Number of Electric Retail Customers, Number of Phone Center Calls, Number of CIS Customer Mailings
Distribution, Customer Ops, and Regulatory Services Administration	Total Assets, 100% to One Company
Energy Supply Administration	100% to One Company
Environment and Safety	MW Generating Capability, 100% to One Company, Number of Employees, Total Assets
Federal Affairs	Total Assets

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LIST OF PRIMARY ALLOCATION FACTORS BY FUNCTION

GROUP/FUNCTION	***PRIMARY ALLOCATION FACTORS***
Fossil & Hydro Generation	100% to One Company, MW Generating Capability
Generation Administration	MW Generating Capability, 100% to One Company
Generation Business Services	MW Generating Capability, 100% to One Company, Level of Construction-Production
Generation Engineering and Technical Services - Engineering Services	100% to One Company, MW Generating Capability
Generation Engineering and Technical Services – Project and Construction	100% to One Company, Level of Construction-Production
Information Technology	100% to One Company, Number of Workstations, Number of Electric Retail Customers, Total Assets, AEPSC Bill Less Indirect and Interest, Level of Construction-Transmission
Investor Relations	Total Assets
Legal	100% to One Company, Total Assets, Total Fixed Assets, Number of Employees
Real Estate & Workplace Services	Total Assets, 100% to One Company, Number of Electric Retail Customers, Number of Employees, Level of Construction-Transmission
Regulated Commercial Operations	Total Peak Load, MWH's Generation, 100% to One Company
Regulatory Services	Total Assets, 100% to One Company, Number of Trans Pole Miles
Risk and Strategic Initiatives	100% to One Company, Total Assets, AEPSC Past 3 Months Total Bill, Total Fixed Assets
Security and Aviation	Number of Employees, AEPSC Past 3 Months Total Bill, Total Gross Utility Plant, 100% to One Company
Supply Chain & Fleet	Number of Purchase Orders, 100% to One

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GROUP/FUNCTION	***PRIMARY ALLOCATION FACTORS***
Operations	Company. Total Assets, Number of Stores Transactions, MW Generating Capability
Transmission Administration	100% to One Company, Number of Transmission Poles Miles
Transmission Asset Strategy and Policy	Number of Transmission Pole Miles, 100% to One Company, Level of Construction-Transmission
Transmission Field Services	100% to One Company, Number of Transmission Pole Miles
Transmission Grid Development & Portfolio Services	Level of Construction-Transmission, Number of Transmission Pole Miles, 100% to One Company, Total Assets
Transmission-Engineering and Project Services	100% to One Company, Level of Construction-Transmission
Treasury	Total Assets, AEPSC Past 3 Months Total Bill, 100% to One Company

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LIST OF AFFILIATE CONTRACTS BY COMPANY

SUMMARY

The following table is a listing of the affiliate contracts with each electric utility in the AEP System.

COMPANY NAME	*DATE*	*CONTRACT*
AEP Texas (formerly AEP Texas Central Company and AEP Texas North Company)	04/26/85	Oklaunion Unit No. 1 Construction ownership and Operating Agreement
	09/14/88	Oklaunion HVDC Project Construction, Ownership and Operating Agreement
	07/01/93	Rail Car Lease Agreement(West)
	01/01/97	CSW Operating Agreement
	07/29/97	Rail Car Maintenance Facility Agreement (West)
	12/22/97	Energy Conservation Measure Utility/Energy Service Company Agency Agreement
	03/26/99	Electric Service Contract between Frontera General Limited Partners and Central Power and Light.
	03/30/99	Interconnection Agreement Between CP&L and Frontera Generation Limited
	06/01/99	CSW System General Agreement
	10/29/99	Transmission Coordination Agreement (West) Regulated Companies
	06/15/00	American Electric Power Company, Inc. and its Consolidated Affiliated Tax Agreement regarding methods of allocated Consolidated Income Tax
	06/15/00	AEPSC Service Agreement with Central Power and Light
	06/15/00	AEPSC Service Agreement with West Texas Utilities Company
	06/16/00	Amended and Restated Purchase Agreement Between CSW Credit, Inc. and Affiliate (West) Companies
	06/26/01	Interconnection Agreement (ERCOT Generation) between AEPTN & PSO
	10/30/01	Construction Agreement/Trent Wind Farm LP
	12/18/02	AEP System Utility Money Pool Agreement

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LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	*DATE*	*CONTRACT*
AEP Texas (formerly AEP Texas Central Company and AEP Texas North Company) (Cont'd)	11/16/04	Interconnection Agreement Between AEP Texas North and PSO
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/05	AEP System Tax Agreement
	01/01/05	American Electric Power Company, Inc. and it's Consolidated Affiliated Tax Agreement regarding methods of allocated consolidated Income Tax
	05/25/07	Power Purchase and Sale Agreement between AEP Texas North and AEP Energy Partners (fna CSW Power Marketing Inc.)
	12/01/09	AEP System Transmission Center Agreement
	03/29/10	Amended and Restated Interconnection Agreement (AEP Texas North)
	03/29/10	Amended and Restated Interconnection Agreement (AEP Texas Central)
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC
	08/08/24	Amended and Restated Central Machine Shop Agreement
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC
Appalachian Power Company	08/11/41	Land Purchase Contract between APCo and the Franklin Real Estate Company
	11/25/70	Purchase Agreement between APCO and Indiana Franklin Realty Inc.
	12/01/76	Indenture Between APCo and Cedar Coal
	03/01/78	Indenture Between APCo and Southern Appalachian Coal Company
	06/01/78	Racine Hydro Operating Agreement
	01/01/79	Central Machine Shop Agreement
	04/01/82	AEP Railcar Use Agreement
	04/01/82	Railcar Maintenance Agreement

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LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	*DATE*	*CONTRACT*
Appalachian Power Company (Cont'd)	10/03/83	Agreement Between Appalachian Power and AEP Pro Service (Formerly AEP Energy Services
	04/01/84	Transmission Agreement
	05/01/86	Barge Transportation Agreement and Appendix A
	07/30/87	Mutual Assistance Agreement
	12/31/96	Affiliated Transactions Agreement (East Companies)
	03/06/97	Agreement Between Appalachian Power and AEP Energy Services Inc.
	06/15/00	American Electric Power and its consolidated Affiliated Tax Agreements regarding methods of allocating consolidated income taxes
	06/16/00	Purchase Agreement Between CSW Credit and its affiliate client companies
	12/18/02	AEP System Utility Money Pool Agreement
	05/04/04	Arrangement for the use of the Amos Simulator
	08/25/04	Third Amended and Restated Purchase Agreement between AEP Credit and Appalachian Power
	08/25/04	Third Amended and Restated Agency Agreement Between AEP Credit and Appalachian Power
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/05	AEP Co, Inc. and its Consolidated Affiliate Tax agreement regarding methods of Allocating Consolidated Income Taxes.
	03/22/06	Amendment No. 1 to the Third Amended and Restated Purchase Agreement between AEP Credit and Appalachian Power
	03/22/06	Amendment No. 1 to the Third Amended and Restated Agency Agreement between AEP Credit and Appalachian Power
	07/01/06	Amendment No. 1 and Consent to AEP System Rail Car Use Agreement
	01/30/08	Amendment No. 2 to the Third Amended and Restated Purchase Agreement between AEP Credit and Appalachian Power

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Appalachian Power Company (Cont'd)	01/30/08	Amendment No. 2 to the Third Amended and Restated Agency Agreement between AEP Credit and Appalachian Power
	11/13/08	Amended and Restated Interconnection Agreement Between Appalachian Power Company and Kingsport Power Company
	02/12/12	Executed Notice of Intent by Ohio Power Company to Terminate Sporn Plant Operating Agreement
	01/22/13	Service Agreement between Appalachian Power and AEP Appalachian Transmission Company, Inc.
	04/24/13	Appalachian Power and AEP West Virginia Transmission Service Agreement "2013 Agreement"
	08/01/13	Railcar Maintenance Agreement
	09/12/13	Amendment No. 2 to AEP System Rail Car Use Agreement
	09/12/13	Amended and Restated Urea Handling Agreement
	09/12/13	Amendment No. 1 to Barge Transportation Agreement
	12/16/13	Amended and Restated Cook Coal Terminal Transfer Agreement
	12/31/13	Termination of Racine Hydro Project Operating
	01/01/14	Affiliated Transactions Agreement for Sharing Capitalized Spare Parts
	01/01/14	Affiliated Transactions Agreement for Sharing Materials and Supplies
	01/01/14	Sporn Plant Operating Agreement
	01/01/14	Simulator Lease Agreement
	01/01/14	Assignment of Central Machine Shop Agreement date January 1, 1979
	01/01/14	Power Coordination Agreement
	10/29/15	Homeserve Service Agreement between AEPSC and Appalachian Power
	04/21/16	APCo sale of Caterpillar Backhoe to SWEPCO
	11/21/16	Services and Property Use Agreement between Appalachian Power and Transource WV

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Appalachian Power Company (Cont'd)	12/20/16	Joint License Agreement between Appalachian Power and AEP Appalachian Transmission Company, Inc.
	10/16/17	AEPSC and APCO Services Agreement
	11/29/17	APCO and AEP Ohio Transmission Company Transmission Asset Sharing Agreement
	10/19/18	Service Agreement with Appalachian Power and AEP West Virginia Transmission Company
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC
	05/09/19	Amended and Restated Urea Handling Agreement Amendment No.1
	05/09/19	Amended and Restated Rail Car Maintenance Agreement Amendment No.1
	05/09/19	Affiliated Transactions Agreement for Sharing Capitalized Spare Parts Amendment No.1
	05/09/19	Barge Transportation Agreement Amendment No.2
	05/09/19	Amended and Restated Cook Coal Terminal Transfer Agreement Amendment No.1
	05/09/19	Affiliated Transactions Agreement for Sharing Materials and Supplies Amendment No.1
	04/23/20	Addendum to Homeserve Service Agreement
	05/13/21	Affiliated Transactions Agreement for Sharing Transmission Assets
	05/13/21	Affiliated Transactions Agreement for Sharing Materials, Equipment, Supplies and Capitalized Spare Parts
	01/20/22	Addendum to Joint License Agreement between Appalachian Power and AEP Appalachian Transmission Company, Inc.
	09/01/22	Amendment No. 3 to AEP System Rail Car Use Agreement
	09/01/22	Amended and Restated Urea Handling Agreement Amendment No.2
	09/01/22	Barge Transportation Agreement Amendment No.3
	09/01/22	Amended and Restated Rail Car Maintenance Agreement Amendment No.2

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Appalachian Power Company (Cont'd)	02/10/22	Addendum to Services and Property Use Agreement between Appalachian Power and Transource WV
	12/13/22	AEPSC and APCO Services Agreement
	04/10/23	Service Agreement with Appalachian Power and AEP West Virginia Transmission Company
	08/08/24	Amended and Restated Central Machine Shop Agreement
	08/08/24	Amended and Restated Cook Coal Terminal Transfer Agreement Amendment No.2
	08/08/24	Amendment to Affiliated Transaction Agreement
	08/08/24	Affiliated Transactions Agreement for Sharing Capitalized Spare Parts Amendment No.2
	08/08/24	Affiliated Transactions Agreement for Sharing Materials and Supplies Amendment No.2
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC
Indiana Michigan Power Company	04/30/48	Purchase Contract between Indiana Franklin Realty, Inc.
	04/04/50	Purchase Contract between The Franklin Real Estate Company.
	01/01/79	Central Machine Shop Agreement/Appalachian Power
	04/01/82	AEP Railcar Use Agreement
	04/01/82	Railcar Maintenance Agreement
	04/08/83	Agreement Between Indiana Michigan Power and AEP ProServ
	04/01/84	Transmission Agreement
	05/01/86	Barge Transportation Agreement & Appendix A
	07/30/87	Mutual Assistance Agreement
	09/27/96	Agreement Between Indiana Michigan Power and AEP Energy Services, Inc.(Formerly AEP Energy Solutions
	06/21/96	AEP Modification No. 1 AEP System Intermin Allowance Agreement

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COMPANY NAME	*DATE*	*CONTRACT*
Indiana Michigan Power Company (Cont'd)	12/31/96	Affiliated Transactions Agreement 1996
	06/15/00	AEPSC Service Agreement with Indiana Michigan Power Company
	06/16/00	Purchase Agreement Between CSW Credit and it's Affiliate Client Companies Indiana Michigan Power Company
	04/21/04	Agency Agreement between CSW Credit, Inc. and Indian Michigan Power Company
	05/04/04	Unit Power Agreement Amendment No 1 between I&M and AEP
	05/04/04	Unit 2 Operating Agreement between I&M and AEG
	08/25/04	Third Amended and Restated Purchase Agreement
	08/25/04	Third Amended and Restated Agency Agreement
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/05	AEP Co. Inc. and it's Consolidated Affiliated Tax Agreement regarding methods of Allocating Consolidated Income Taxes
	07/01/06	Amendment No 1 & Consent to AEP System Railcar Use Agreement
	05/16/07	Indiana Michigan Power Company & AEP Generating Company Operation and Maintenance Agreement
	02/15/11	Transmission Service Agreement between Indiana Michigan Power Company and AEP Indiana Michigan Transmission Company
	02/15/11	Joint License Agreement between Indiana Michigan Power Company and AEP Indiana Michigan Transmission Company
	08/01/13	Rail Car Maintenance Agreement
	09/12/13	Amendment No. 1 to Barge Transportation Agreement
	09/12/13	Amendment No. 2 to AEP System Rail Car Use
	12/16/13	Amended and Restated Urea Handling Agreement
	12/16/13	Amended and Restated Cook Coal Terminal Transfer Agreement

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Indiana Michigan Power Company (Cont'd)	01/01/14	Affiliated Transactions Agreement for Sharing Capitalized Spare Parts
	01/01/14	Affiliated Transactions Agreement for Sharing Materials and Supplies
	01/01/14	Urea Handling Agreement (AEP Generation Resources)
	01/01/14	Power Coordination Agreement
	05/22/14	System Transmission Integration Agreement Termination
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC
	05/09/19	Amended and Restated Urea Handling Agreement Amendment No.1
	05/09/19	Amended and Restated Rail Car Maintenance Agreement Amendment No.1
	05/09/19	Affiliated Transactions Agreement for Sharing Capitalized Spare Parts Amendment No.1
	05/09/19	Barge Transportation Agreement Amendment No.2
	05/09/19	Amended and Restated Cook Coal Terminal Transfer Agreement Amendment No.1
	05/09/19	Affiliated Transactions Agreement for Sharing Materials and Supplies Amendment No.1
	05/13/21	Affiliated Transactions Agreement for Sharing Transmission Assets
	05/13/21	Affiliated Transactions Agreement for Sharing Materials, Equipment, Supplies and Capitalized Spare Parts
	09/01/22	Amendment No. 3 to AEP System Rail Car Use Agreement
	09/01/22	Amended and Restated Urea Handling Agreement Amendment No.2
	09/01/22	Amended and Restated Rail Car Maintenance Agreement Amendment No.2
	08/08/24	Amended and Restated Central Machine Shop Agreement
	08/08/24	Amended and Restated Cook Coal Terminal Transfer Agreement Amendment No.2
	08/08/24	Amendment to Affiliated Transaction Agreement

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COMPANY NAME	*DATE*	*CONTRACT*
Indiana Michigan Power Company (Cont'd)	08/08/24	Affiliated Transactions Agreement for Sharing Capitalized Spare Parts Amendment No.2
	08/08/24	Affiliated Transactions Agreement for Sharing Materials and Supplies Amendment No.2
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC
Kentucky Power Company	06/07/63	Purchase Contract between KPCO and The Franklin Real Estate Company
	03/31/75	Purchase Contract between KPCO and Indiana Franklin Realty, Inc.
	01/01/79	Central Machine Shop Agreement/Appalachian Power
	04/01/84	Transmission Agreement
	07/30/87	Mutual Assistance Agreement
	09/27/96	Agreement between Kentucky Power and AEP Energy Services, Inc.
	12/31/96	Affiliated Transactions Agreement (East Companies)
	11/18/97	Agreement between Kentucky Power and AEP Communications, LLC
	01/01/98	Master Site Agreements (East) With AEP Operating Companies
	06/15/00	AEP Co. Inc. and it's Consolidated Affiliated Tax Agreement regarding methods of Allocating Consolidated Income Taxes
	06/15/00	AEPSC Service Agreement with Kentucky Power
	06/16/00	Purchase Agreement between AEP Credit and it's Affiliate Client Companies
	12/18/02	AEP System Utility Money Pool Agreement
	05/04/04	Arrangement for the Use of the Amos Simulator
	08/25/04	Third Amended and Restated Purchase Agreement Between AEP Credit and Kentucky Power
	08/25/04	Third Amended and Restated Agency Agreement Between AEP Credit and Kentucky Power

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COMPANY NAME	*DATE*	*CONTRACT*
Kentucky Power Company (Cont'd)	12/09/04	AEP System Amended and Restated Money Pool Agreement
	01/01/05	American Electric Power Company, Inc. and it's Consolidated Affiliated Tax Agreement regarding methods of Allocating Consolidated Income Taxes
	08/01/13	Railcar Maintenance Agreement
	09/12/13	Amendment No. 1 to Barge Transportation Agreement
	09/12/13	Amendment No. 2 to AEP System Rail Car Use
	12/16/13	Amended and Restated Urea Handling Agreement
	12/16/13	Amended and Restated Cook Coal Terminal Transfer Agreement
	01/01/14	Affiliated Transactions Agreement for Sharing Capitalized Spare Parts
	01/01/14	Affiliated Transactions Agreement for Sharing Materials and Supplies
	01/01/14	Mitchell Coal Pile Run-Off Agreement
	01/01/14	Power Coordination Agreement
	01/31/15	Mitchell Plant Operating Agreement between Wheeling Power, Kentucky Power, and AEPSC
	02/27/15	Service Agreement between Kentucky Power Company and AEP Kentucky Transmission Company, Inc.
	02/27/15	Joint License Agreement between Kentucky Power Company and AEP Kentucky Transmission Company, Inc.
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC
	05/09/19	Amended and Restated Urea Handling Agreement Amendment No.1
	05/09/19	Amended and Restated Rail Car Maintenance Agreement Amendment No.1
	05/09/19	Affiliated Transactions Agreement for Sharing Capitalized Spare Parts Amendment No.1
	05/09/19	Barge Transportation Agreement Amendment No.2
	05/09/19	Amended and Restated Cook Coal Terminal Transfer Agreement Amendment No.1

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Kentucky Power Company (Cont'd)	05/09/19	Affiliated Transactions Agreement for Sharing Materials and Supplies Amendment No.1
	05/13/21	Affiliated Transactions Agreement for Sharing Transmission Assets
	05/13/21	Affiliated Transactions Agreement for Sharing Materials, Equipment, Supplies and Capitalized Spare Parts
	09/01/22	Amendment No. 3 to AEP System Rail Car Use Agreement
	09/01/22	Amended and Restated Urea Handling Agreement Amendment No.2
	09/01/22	Amended and Restated Rail Car Maintenance Agreement Amendment No.2
	08/08/24	Amended and Restated Central Machine Shop Agreement
	08/08/24	Amended and Restated Cook Coal Terminal Transfer Agreement Amendment No.2
	08/08/24	Amendment to Affiliated Transaction Agreement
	08/08/24	Affiliated Transactions Agreement for Sharing Capitalized Spare Parts Amendment No.2
	08/08/24	Affiliated Transactions Agreement for Sharing Materials and Supplies Amendment No.2
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC
Kingsport Power Company	01/01/72	Purchase Contract Between KGPCO and Indiana Franklin Realty, Inc.
	07/30/87	Mutual Assistance Agreement
	09/27/96	Agreement Between Kingsport Power Company and AEP Energy Services
	12/31/96	Affiliate Transactions Agreement (East Companies)
	01/01/98	Master Site Agreement (East) with AEP Operating Companies

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Kingsport Power Company (Cont'd)	06/15/00	AEP Co, Inc and it's Consolidated Affiliate Tax Agreement regarding methods of Allocating Consolidated Income Tax
	06/15/00	AEPSC Service Agreement with Kingsport Power
	06/16/00	Purchase Agreement Between CSW Credit and Affiliate Client Companies
	12/18/02	AEP System Utility Money Pool Agreement
	08/25/04	Third Amended and Restated Purchase Agreement Between AEP Credit and Kingsport Power
	08/25/04	Third Amended and Restated Agency Agreement Between AEP Credit and Kingsport Power
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/05	American Electric Power Company, Inc. and it's Consolidated Affiliate Tax Agreement Regarding methods of Allocating Consolidated Income Taxes
	11/13/08	Amended and Restated Interconnection Agreement Between Appalachian Power Company and Kingsport Power Company
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC
	05/13/21	Affiliated Transactions Agreement for Sharing Transmission Assets
	05/13/21	Affiliated Transactions Agreement for Sharing Materials, Equipment, Supplies and Capitalized Spare Parts
	08/08/24	Amendment to Affiliated Transaction Agreement
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC
Ohio Power Company	08/11/41	Land Purchase Contract/Franklin Real Estate Company
	11/25/70	Purchase Contract/Indiana Franklin Realty, Inc.
	04/01/84	Transmission Agreement

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Ohio Power Company (Cont'd)	07/30/87	Mutual Assistance Agreement
	06/21/96	AEP Modifications No. 1 AEP System Interim Allowance Agreement
	09/27/96	Agreement between Ohio Power Company and AEP Energy Services
	12/31/96	Affiliated Transactions Agreement (East Companies)
	01/01/98	Master Site Agreement (East) with AEP Operating Companies
	06/15/00	American Electric Power Company, Inc. and its Consolidated Affiliate Tax Agreement regarding Methods of Allocating Consolidated Income Taxes
	06/15/00	AEPSC Service Agreement with Ohio Power
	06/16/00	Purchase Agreement Between AEP Credit Inc. and Affiliate Client Companies
	12/18/02	AEP System Utility Money Pool Agreement
	08/25/04	Third Amended and Restated Purchase Agreement
	08/25/04	Third Amended and Restated Agency Agreement
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/05	AEP Co, Inc and It's Consolidated Affiliate Tax Agreement regarding methods of Allocating Consolidated Income Taxes
	12/01/09	Transmission Center Agreement
	01/01/11	Transmission Service Agreement between Ohio Power Company and AEP Ohio Transmission Company
	01/01/11	Joint License Agreement between Ohio Power Company and AEP Ohio Transmission Company
	02/12/12	Executed Notice of Intent by Ohio Power Company to Terminate Sporn Plant Operating Agreement
	03/27/13	Service Agreement between Ohio Power Company and AEP West Virginia Transmission Company
	12/31/14	Affiliated Transactions Agreement for Sharing Materials and Supplies

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Ohio Power Company (Cont'd)	01/01/14	Assignment of Central Machine Shop Agreement dated January 1, 1979
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC
	05/09/19	Affiliated Transactions Agreement for Sharing Materials and Supplies Amendment No.1
	05/13/21	Affiliated Transactions Agreement for Sharing Transmission Assets
	05/13/21	Affiliated Transactions Agreement for Sharing Materials, Equipment, Supplies and Capitalized Spare Parts
	08/08/24	Amended and Restated Central Machine Shop Agreement
	08/08/24	Amendment to Affiliated Transaction Agreement
	08/08/24	Affiliated Transactions Agreement for Sharing Materials and Supplies Amendment No.2
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC
	11/15/24	Asset Purchase Agreement with AEP Development Services, LLC
Public Service Company of Oklahoma	04/26/85	Oklaunion Unit No. 1 Construction, Ownership and Operating Agreement
	09/14/88	Oklaunion HVDC Project Construction, Ownership and Operating Agreement
	07/01/93	Rail Car Lease Agreement(West)
	08/03/95	East HVDC Interconnection Agreement/West Regulated Companies
	01/01/97	CSW Operating Agreement
	06/01/99	CSW System General Agreement
	10/29/99	Transmission Coordination Agreement(West)
	06/15/00	American Electric Power Company, Inc. and its Consolidated Affiliate Tax Agreements
	06/15/00	AEPSC Service Agreement with Public Service Company of Oklahoma

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Public Service Company of Oklahoma (Cont'd)	06/16/00	Amended and Restated Agency Agreement Between CSW Credit and its Affiliates
	06/16/00	Amended and Restated Purchase Agreement Between CSW Credit and it's Affiliates Operating Agreement-PSO, SWEPCO, AEPSC
	12/21/01	AEP System Utility Money Pool Agreement
	07/25/03	Second Amended and Restated Agency Agreement between AEP Credit and Public Service Company of Oklahoma
	07/25/03	Second Amended and Restated Purchase Agreement between AEP Credit and Public Service Company of Oklahoma
	08/25/04	Third Amended and Restated Purchase Agreement
	08/25/04	Third Amended and Restated Agency Agreement
	11/16/04	Interconnection Agreement (ERCOT Generation) between AEPTN & PSO.
	12/09/04	AEP System Amended and Restated Money Pool Agreement
	01/01/05	American Electric Power Company, and it's Consolidated Tax Affiliates
	02/10/05	Operating Agreement PSO, SWEPCO and AEPSC
	07/01/06	Amendment No 1 and consent to AEP System Rail Car Use Agreement
	12/01/09	AEP System Transmission Center Agreement
	01/01/10	Transmission Service Agreement between Public Service Company of Oklahoma and AEP Oklahoma Transmission Company
	01/01/10	Joint License Agreement between Public Service Company of Oklahoma and AEP Oklahoma Transmission Company
	08/01/13	Rail Car Maintenance Agreement
	09/12/13	Amendment No. 2 to AEP System Rail Car Use Agreement
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC
	05/09/19	Amended and Restated Rail Car Maintenance Agreement Amendment No.1
	04/14/21	Sundance Wind Facilities Operating Agreement

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Public Service Company of Oklahoma (Cont'd)	05/13/21	Affiliated Transactions Agreement for Sharing Materials, Equipment, Supplies and Capitalized Spare Parts
	09/10/21	Maverick Wind Facilities Operating Agreement
	03/18/22	Traverse Wind Facilities Operating Agreement
	09/01/22	Amendment No. 3 to AEP System Rail Car Use Agreement
	09/01/22	Amended and Restated Rail Car Maintenance Agreement Amendment No.2
	08/08/24	Amended and Restated Central Machine Shop Agreement
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC
Southwestern Electric Power Company	07/01/93	Rail Car Lease Agreement (West)
	08/03/95	East HVDC Interconnection Use and Maintenance Agreement
	01/01/97	CSW Operating Agreement
	06/01/99	CSW System General Agreement
	07/08/99	Memorandum of Understanding (West) Between C3 Communications, Public Service Company,
	10/29/99	Transmission Coordination Agreement (West)
	06/15/00	American Electric Power Company, Inc. and its Consolidated Affiliates Tax Agreements
	06/15/00	AEPSC Service Agreement with Southwest Power Electric
	06/16/00	Amended and Restated Purchase Agreement Between CSW and Affiliate (West) Companies
	05/31/01	Lignite Mining Agreement
	12/21/01	Operating Agreement PSO, SWEPCo, AEPSC
	08/06/02	Interconnection Agreement Between SWEPCo and Eastex Cogeneration LP
	12/18/02	AEP System Utility Money Pool Agreement
	07/25/03	Second Amended and Restated Agency Agreement Between AEP Credit and SWEPCo

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Southwestern Electric Power Company (Cont'd)	07/25/03	Second Amended and Restated Purchase Agreement Between AEP Credit and SWEPCo
	08/25/04	Third Amended and Restated Purchase Agreement Between AEP Credit and Southwestern Electric Power
	08/25/04	Third Amended and Restated Agency Agreement Between AEP Credit and Southwestern Electric Power
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/05	American Electric Power Company, Inc. and Its Consolidated Affiliated Tax Agreements
	02/10/05	Operating Agreement PSO, SWEPCO, AEPSC
	07/01/06	Amendment No 1 and Consent to AEP System Rail Car Use
	12/01/09	AEP System Transmission Center Agreement
	12/29/09	Amended and Restated Lignite Mining Agreement
	05/06/11	Transmission Service Agreement between Southwestern Electric Power Company and AEP Southwestern Transmission Company
	05/06/11	Joint License Agreement between Southwestern Electric Power Company and AEP Southwestern Transmission Company
	08/01/13	Rail Car Maintenance Agreement
	09/12/13	Amendment No. 2 to AEP System Rail Car Use
	12/31/13	Assignment, Assumption and Consent Agreement of Rail Car Assets
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC
	05/09/19	Amended and Restated Rail Car Maintenance Agreement Amendment No.1
	04/14/21	Sundance Wind Facilities Operating Agreement
	05/13/21	Affiliated Transactions Agreement for Sharing Materials, Equipment, Supplies and Capitalized Spare Parts
	09/10/21	Maverick Wind Facilities Operating Agreement
	03/18/22	Traverse Wind Facilities Operating Agreement

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Southwestern Electric Power Company (Cont'd)	09/01/22	Amendment No. 3 to AEP System Rail Car Use Agreement
	09/01/22	Amended and Restated Rail Car Maintenance Agreement Amendment No.2
	08/08/24	Amended and Restated Central Machine Shop Agreement
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC
Wheeling Power Company	08/11/41	Land Purchase Contract/The Franklin Real Estate Company
	07/30/87	Mutual Assistance Agreement
	12/31/96	Affiliated Transactions Agreement (East Companies)
	01/09/97	Agreement between Wheeling Power Company and AEP Energy Services, Inc.
	03/01/98	Pole Attachment License Agreement/AEP Communications LLC
	06/15/00	AEP System Tax Agreement
	12/18/02	AEP System Utility Money Pool Agreement
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/05	American Electric Power Company, and it's Consolidated Tax Affiliates
	05/15/08	Agreement between Wheeling Power Company and AEPSC
	01/22/13	Service Agreement between Wheeling Power Company and AEP West Virginia Transmission Company, Inc.
	12/18/14	Agreement of Representation for EPA Allowances between AEPSC and Wheeling Power
	01/31/15	Mitchell Plant Operating Agreement between Wheeling Power, Kentucky Power and AEPSC
	06/01/15	Power Coordination Agreement
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC

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Wheeling Power Company (Cont'd)	05/13/21	Affiliated Transactions Agreement for Sharing Materials, Equipment, Supplies and Capitalized Spare Parts
	09/01/22	Amendment No. 3 to AEP System Rail Car Use Agreement
	09/01/22	Amended and Restated Urea Handling Agreement Amendment No.2
	09/01/22	Barge Transportation Agreement Amendment No.3
	09/01/22	Amended and Restated Rail Car Maintenance Agreement Amendment No.2
	08/08/24	Amended and Restated Central Machine Shop Agreement
	08/08/24	Amended and Restated Cook Coal Terminal Transfer Agreement Amendment No.2
	08/08/24	Amendment to Affiliated Transaction Agreement
	08/08/24	Affiliated Transactions Agreement for Sharing Capitalized Spare Parts Amendment No.2
	08/08/24	Affiliated Transactions Agreement for Sharing Materials and Supplies Amendment No.2
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC
Electric Transmission Texas	12/21/07	Electric Transmission Texas Service Agreement (AEPSC)
	03/29/10	Amended and Restated Interconnection Agreement (AEP Texas North)
	03/29/10	Amended and Restated Interconnection Agreement (AEP Texas Central)
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance.
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC

AEP AMERICAN ELECTRIC POWER

Document Number **99-00-06**

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	*DATE*	*CONTRACT*
PATH West Virginia Transmission Company	09/01/07	PATH West Virginia Transmission Company Service Agreement
AEP Appalachian Transmission Company	01/22/13	Service Agreement between Appalachian Power Company and AEP Appalachian Transmission Company, Inc.
	12/20/16	Joint License Agreement between Appalachian Power Company and AEP Appalachian Transmission Company, Inc.
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC
	05/13/21	Affiliated Transactions Agreement for Sharing Transmission Assets
	01/20/22	Addendum to Joint License Agreement between Appalachian Power and AEP Appalachian Transmission Company, Inc.
	08/08/24	Amended and Restated Central Machine Shop Agreement
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC
AEP Indiana Michigan Transmission Company	02/15/11	Transmission Company Services Agreement between AEP Indiana Michigan Transmission Company and Indiana Michigan Power Company
	02/15/11	Joint License Agreement between AEP Indiana Michigan Transmission Company and Indiana Michigan Power Company
	02/15/11	Service Agreement between AEP Indiana Michigan Transmission Company and American Electric Power Service Corporation
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC
	05/13/21	Affiliated Transactions Agreement for Sharing Transmission Assets

AEP AMERICAN ELECTRIC POWER

Document Number **99-00-06**

Cost Allocation Manual

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Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	*DATE*	*CONTRACT*
AEP Indiana Michigan Transmission Company (Cont'd)	08/08/24	Amended and Restated Central Machine Shop Agreement
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC
AEP Kentucky Transmission Company	02/27/15	Service Agreement between Kentucky Power Company and AEP Kentucky Transmission Company, Inc.
	02/27/15	Joint License Agreement between Kentucky Power Company and AEP Kentucky Transmission Company, Inc.
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC
	05/13/21	Affiliated Transactions Agreement for Sharing Transmission Assets
	08/08/24	Amended and Restated Central Machine Shop Agreement
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC
AEP Ohio Transmission Company	01/01/11	Transmission Company Services Agreement between AEP Ohio Transmission Company and Ohio Power Company
	01/01/11	Transmission Company Services Agreement between AEP Ohio Transmission Company and Columbus Southern Power Company
	01/01/11	Joint License Agreement between AEP Ohio Transmission Company and Ohio Power Company
	01/01/11	Joint License Agreement between AEP Ohio Transmission Company and Columbus Southern Power Company

AEP AMERICAN ELECTRIC POWER

Document Number **99-00-06**

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Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	*DATE*	*CONTRACT*
AEP Ohio Transmission Company (Cont'd)	01/01/11	Service Agreement between AEP Ohio Transmission Company and American Electric Power Service Corporation
	11/29/17	APCO and AEP Ohio Transmission Company Transmission Asset Sharing Agreement
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC
	05/13/21	Affiliated Transactions Agreement for Sharing Transmission Assets
	08/08/24	Amended and Restated Central Machine Shop Agreement
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC
AEP Oklahoma Transmission Company	01/01/10	Transmission Company Services Agreement between AEP Oklahoma Transmission Company and Public Service Company of Oklahoma
	01/01/10	Joint License Agreement between AEP Oklahoma Transmission Company and Public Service Company of Oklahoma
	10/27/10	Service Agreement between AEP Oklahoma Transmission Company and American Electric Power Service Corporation
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC
	05/13/21	Affiliated Transactions Agreement for Sharing Materials, Equipment, Supplies and Capitalized Spare Parts
	08/08/24	Amended and Restated Central Machine Shop Agreement
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC

AEP AMERICAN ELECTRIC POWER

Document Number **99-00-06**

Cost Allocation Manual

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LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	*DATE*	*CONTRACT*
AEP Southwestern Transmission Company	05/06/11	Transmission Company Services Agreement between AEP Southwestern Transmission Company and Southwestern Electric Power
	05/06/11	Joint License Agreement between AEP Southwestern Transmission Company and Southwestern Electric Power Company
	05/06/11	Service Agreement between AEP Southwestern Transmission Company and AEPSC
	08/08/24	Amended and Restated Central Machine Shop Agreement
AEP West Virginia Transmission Company	01/22/13	Service Agreement between Wheeling Power and AEP West Virginia Transmission Company,Inc.
	03/27/13	Service Agreement between Ohio Power and AEP West Virginia Transmission Company
	04/24/13	Service Agreement with Appalachian Power and AEP West Virginia Transmission Company "2013 Agreement"
	01/22/13	Service Agreement between AEPSC and AEP West Virginia Transmission Company, Inc.
	10/19/18	Service Agreement with Appalachian Power and AEP West Virginia Transmission Company
	04/02/19	Amended and Restated Subscription Agreement with Grid Assurance LLC
	05/13/21	Affiliated Transactions Agreement for Sharing Transmission Assets
	04/10/23	Service Agreement with Appalachian Power and AEP West Virginia Transmission Company
	08/08/24	Amended and Restated Central Machine Shop Agreement
	11/12/24	Amended and Restated Subscription Agreement with Grid Assurance LLC No.2
	11/12/24	Amended and Multi-Subscriber Addendum to the Amended and Restated Subscription Agreement with Grid Assurance LLC
Transource Energy, LLC	04/03/12	Service Agreement between Transource Energy, LLC and AEPSC
	07/01/16	Service Agreement between Transource West Virginia, LLC and Transource Energy

AEP AMERICAN ELECTRIC POWER

Document Number **99-00-06**

Cost Allocation Manual

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Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	*DATE*	*CONTRACT*
Transource Energy, LLC (Cont'd)	09/26/16 01/23/18	Service Agreement between Transource Energy, LLC and Transource Maryland, LLC Service Agreement between Transource Pennsylvania, LLC and Transource Energy, LLC
Transource Maryland, LLC	09/26/16	Service Agreement between Transource Energy, LLC and Transource Maryland, LLC
Transource Missouri, LLC	12/27/13	Service Agreement between Transource Missouri, LLC and Transource Energy, LLC.
Transource Pennsylvania, LLC	01/23/18	Service Agreement between Transource Pennsylvania, LLC and Transource Energy, LLC
Transource West Virginia, LLC	07/01/16 11/21/16 02/10/22	Service Agreement between Transource WV and Transource Energy Services and Property Use Agreement between Appalachian Power and Transource WV Addendum to Services and Property Use Agreement between Appalachian Power and Transource WV

Commonwealth of Kentucky
Michael G. Adams, Secretary of State

Michael G. Adams
Secretary of State
P. O. Box 718
Frankfort, KY 40602-0718
(502) 564-3490
http://www.sos.ky.gov

Certificate of Existence

Authentication number: 342365
Visit https://web.sos.ky.gov/ftshow/certvalidate.aspx to authenticate this certificate.

I, Michael G. Adams, Secretary of State of the Commonwealth of Kentucky, do hereby certify that according to the records in the Office of the Secretary of State,

KENTUCKY POWER COMPANY

KENTUCKY POWER COMPANY is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B, whose date of incorporation is July 21, 1919 and whose period of duration is perpetual.

I further certify that all fees and penalties owed to the Secretary of State have been paid; that Articles of Dissolution have not been filed; and that the most recent annual report required by KRS 14A.6-010 has been delivered to the Secretary of State.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 25th day of August, 2025, in the 234th year of the Commonwealth.

Michael G. Adams
Secretary of State
Commonwealth of Kentucky
342365/0028317

0028317.09 vmiller ASN

Michael G. Adams
Kentucky Secretary of State
Received and Filed:
11/12/2021 11:22 AM
Fee Receipt: $20.00

COMMONWEALTH OF KENTUCKY
MICHAEL G. ADAMS, SECRETARY OF STATE

Division of Business Filings
Business Filings
P.O. Box 718,
Frankfort, KY 40602
(502) 564-3490
www.sos.ky.gov

Certificate of Assumed Name
(Domestic or Foreign Business Entity)

ASN

Pursuant to the provisions of KRS 365, the undersigned applies to assume a name and, for that purpose, submits the following statement:

1. The assumed name is: Kentucky Power

2. The name of the business entity (and in the case of general partnership, the partners) that is/are adopting the assumed name:

Kentucky Power Company
Name must be identical to the name on record with the Secretary of State.)

3. The "real name" is **(you must check one):**

☐ a Domestic General Partnership	☐ a Foreign General Partnership
☐ a Domestic Limited Liability Partnership	☐ a Foreign Limited Liability Partnership
☐ a Domestic Limited Partnership	☐ a Foreign Limited Partnership
☐ a Domestic Business Trust	☐ a Foreign Business Trust
☒ a Domestic Corporation	☐ a Foreign Corporation
☐ a Domestic Limited Liability Company	☐ a Foreign Limited Liability Company
☐ a Domestic Statutory Trust	☐ a Foreign Statutory Trust
☐ a Domestic Limited Cooperative Association	☐ a Foreign Limited Cooperative Association
☐ a Domestic Unincorporated Non-profit Association	☐ a Foreign Unincorporated Non-profit Association

4. The business is organized and existing in the state or country of KENTUCKY

5. The mailing address is:

1 RIVERSIDE PLAZA	COLUMBUS	OH	43215
Street Address or Post Office Box Numbers	**City**	**State**	**Zip**

I declare under penalty of perjury under the laws of Kentucky that the forgoing is true and correct.

Robin S. Richey	Robin S. Richey	Authorized Representativ	November 9, 2021
Authorized Party Signature	**Printed Name**	**Title**	**Date**

(7/20)

KY011 - 09-01-2020 Wolters Kluwer Online

0028317.09 vmiller ASN

Michael G. Adams
Kentucky Secretary of State
Received and Filed:
11/12/2021 11:22 AM
Fee Receipt: $20.00

COMMONWEALTH OF KENTUCKY
MICHAEL G. ADAMS, SECRETARY OF STATE

Division of Business Filings
Business Filings
P.O. Box 718,
Frankfort, KY 40602
(502) 564-3490
www.sos.ky.gov

Certificate of Assumed Name
(Domestic or Foreign Business Entity)

ASN

Pursuant to the provisions of KRS 365, the undersigned applies to assume a name and, for that purpose, submits the following statement:

1. The assumed name is: AEP Kentucky Power

2. The name of the business entity (and in the case of general partnership, the partners) that is/are adopting the assumed name:

Kentucky Power Company
Name must be identical to the name on record with the Secretary of State.)

3. The "real name" is (you must check one):

[ ] a Domestic General Partnership	[ ] a Foreign General Partnership
[ ] a Domestic Limited Liability Partnership	[ ] a Foreign Limited Liability Partnership
[ ] a Domestic Limited Partnership	[ ] a Foreign Limited Partnership
[ ] a Domestic Business Trust	[ ] a Foreign Business Trust
[X] a Domestic Corporation	[ ] a Foreign Corporation
[ ] a Domestic Limited Liability Company	[ ] a Foreign Limited Liability Company
[ ] a Domestic Statutory Trust	[ ] a Foreign Statutory Trust
[ ] a Domestic Limited Cooperative Association	[ ] a Foreign Limited Cooperative Association
[ ] a Domestic Unincorporated Non-profit Association	[ ] a Foreign Unincorporated Non-profit Association

4. The business is organized and existing in the state or country of KENTUCKY

5. The mailing address is:

1 RIVERSIDE PLAZA	COLUMBUS	OH	43215
Street Address or Post Office Box Numbers	City	State	Zip

I declare under penalty of perjury under the laws of Kentucky that the forgoing is true and correct.

Robin S. Richey	Robin S. Richey	Authorized Representativ	November 9, 2021
Authorized Party Signature	Printed Name	Title	Date

(7/20)

KY011 -09.01/2020 Wolters Kluwer Online

0028317.09	vmiller ASN
Michael G. Adams **Kentucky Secretary of State** Received and Filed: 2/18/2021 10:16 AM Fee Receipt: $20.00	

COMMONWEALTH OF KENTUCKY
MICHAEL G. ADAMS, SECRETARY OF STATE

Division of Business Filings
Business Filings
P.O. Box 718,
Frankfort, KY 40602
(502) 564-3490
www.sos.ky.gov

Certificate of Assumed Name
(Domestic or Foreign Business Entity)

ASN

Pursuant to the provisions of KRS 365, the undersigned applies to assume a name and, for that purpose, submits the following statement:

1. The assumed name is: American Electric Power.
2. The name of the business entity (and in the case of general partnership, the partners) that is/are adopting the assumed name:

Kentucky Power Company

Name must be identical to the name on record with the Secretary of State.)

3. The "real name" is **(you must check one)**:

☐ a Domestic General Partnership	☐ a Foreign General Partnership
☐ a Domestic Limited Liability Partnership	☐ a Foreign Limited Liability Partnership
☐ a Domestic Limited Partnership	☐ a Foreign Limited Partnership
☐ a Domestic Business Trust	☐ a Foreign Business Trust
☒ a Domestic Corporation	☐ a Foreign Corporation
☐ a Domestic Limited Liability Company	☐ a Foreign Limited Liability Company
☐ a Domestic Statutory Trust	☐ a Foreign Statutory Trust
☐ a Domestic Limited Cooperative Association	☐ a Foreign Limited Cooperative Association
☐ a Domestic Unincorporated Non-profit Association	☐ a Foreign Unincorporated Non-profit Association

4. The business is organized and existing in the state or country of Kentucky.
5. The mailing address is:

1 RIVERSIDE PLAZA COLUMBUS, OH 43215

Street Address or Post Office Box Numbers | **City** | **State** | **Zip**

I declare under penalty of perjury under the laws of Kentucky that the forgoing is true and correct.

Heather Paarlberg — Heather Paarlberg — Secretary — 2/17/2021

Authorized Party Signature | **Printed Name** | **Title** | **Date**

(7/20)

P.S.C. KY. NO. 14
CANCELLING P.S.C. KY. NO. 13

T

Kentucky Power Company

1645 Winchester Avenue
Ashland, KY 41101
www.kentuckypower.com

Rates, Terms, and Conditions for Furnishing
Electric Service

Applicable to the Entire Territory Served by Kentucky Power Company In: Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Johnson, Knott, Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike, and Rowan Counties.

Filed with the Kentucky Public Service Commission

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On and After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

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Continued on Sheet 1-2 T

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On and After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

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Terms and Conditions of Service

1. Application

Applications may be made in writing, online, or via telephone for customers who wish to have the Company provide electric service. Requests for service are to be made in the Customer's legal name by telephone or online at: www.kentuckypower.com. The Company has the right to reject any request for service based on 807 KAR 5:006 Section 15 and associated tariffs. T

The Company may require verification of ownership of property, lease, applicant's identity, or other requested information.

A copy of the tariffs and standard terms and conditions under which service is to be rendered to the Customer will be furnished upon request and the Customer shall elect upon which tariff applicable to his service his application shall be based. A copy of the tariff is also available online at www.kentuckypower.com.

If the Company requires a written agreement from a Customer before service will be commenced, a copy of the agreement will be furnished to the Customer upon request.

When the Customer desires delivery of energy at more than one point, a separate agreement may be required for each separate point of delivery. Service delivered at each point of delivery will be billed separately under the applicable tariff.

2. Inspection

The Customer is responsible for the proper installation and maintenance of the customer's wiring and electrical equipment and the customer shall at all times be responsible for the character and condition thereof. The Company has no obligation to undertake inspection thereof and in no event shall be responsible therefore. However, the Company may disconnect or refuse to connect service if the customer's wiring is deemed unsafe by the Company.

Company may also require a new state electrical inspection should tampering, illegal use or theft of service be the basis for disconnection service.

Where a Customer's premises are located in a municipality or other governmental subdivision where inspection laws or ordinances are in effect, the Company may withhold furnishing service to new installations until the Company has received evidence that the inspection laws or ordinances have been complied with.

Where a Customer's premises are located outside of an area where inspection service is in effect, the Company may require the delivery by the Customer to the Company of an agreement duly signed by the owner and/or tenant of the premises authorizing the connection to the wiring system of the Customer and assuming responsibility therefore. No responsibility shall attach to the Company because of any waiver of this requirement.

3. Service Connections

Service connections will be provided in accordance with 807 KAR-5:041, Section 10.

The Customer should in all cases consult the Company before the Customer's premises are wired to determine the location of Company's point of service connection.

Continued on Sheet 2-2

Terms and Conditions of Service Continued

Service Connections Continued

The Company will, when requested to furnish service, designate the location of its service connection. The Customer's wiring must, except for those cases listed below, be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto. When service is from an overhead system, the Customer's wiring must extend at least 18 inches beyond the building. Where Customers install service entrance facilities which have capacity and layout specified by the Company and/or install and use certain equipment specified by the Company, the Company may supply or offer to own certain facilities on the Customer's side of the point where the service wires attach to the building
All inside wiring must be grounded in accordance with the requirements of the National Electrical Code or the requirements of any local inspection service authorized by a state or local authority.

When a Customer desires that energy be delivered at a point or in a manner other than that designated by the Company, the Customer shall pay the additional cost of same.

4. Deposits

Prior to providing service or at any time thereafter, the Company may require a cash deposit or other guaranty acceptable to the Company to secure payment of bills except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection. Service may be refused or discontinued for failure to pay the requested deposit. Upon request from a residential customer the deposit will be returned after 18 months if the customer has established a satisfactory payment record; but commercial deposits will be retained by the Company during the entire time that the account remains active.

A. Interest

Interest will be paid on all sums held on deposit at the rate indicated in KRS 278.460. The interest will be applied by the Company as a credit to the Customer's bill or will be paid to the Customer on an annual basis. If the deposit is refunded or credited to the Customer's bill prior to the deposit anniversary date, interest will be paid or credited to the Customer's bill on a pro-rated basis.

The Company will not pay interest on deposits after discontinuance of service to the Customer. Retention of any deposit or guaranty by the Company prior to final settlement is not a payment or partial payment of any bill for service. The Company shall have a reasonable time in which to obtain a final reading and to ascertain that the obligations of the Customer have been fully performed before being required to return any deposits.

B. Criteria for Waiver of Deposit Requirement

The Company may waive any deposit requirement based upon the following criteria, which may be considered by the Company cumulatively:

i. Satisfactory payment history with the Company, which may be established by paying all bills by due date, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments and having no energy diversion or theft of service;
ii. Satisfactory payment history with another utility acceptable to the Company;
iii. Another customer with satisfactory payment history is willing to sign as a guarantor for an amount equal to the required deposit; or
iv. Providing evidence of other collateral acceptable to Company.

Continued on Sheet 2-3

Terms and Conditions of Service Continued

C. Method of Determination – Calculated Deposits

a. Deposit amounts paid by residential customers shall not exceed a calculated amount based upon actual usage data of the Customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the average bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the Customer's actual or estimated annual bill.

b. Deposit amounts paid by commercial and industrial customers shall not exceed a calculated amount based upon actual usage data of the customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the typical bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the customer's actual or estimated annual bill.

D. Additional or Supplemental Deposit Requirement

An additional or supplemental deposit may be required if the Customer does not maintain a satisfactory credit criteria or payment history. If a change in usage or classification of service has occurred, the customer may be required to pay an additional deposit up to 2/12 of the annual usage. The Customer will receive a message on the bill informing the Customer that if the account is not current by the specified date listed an additional or supplemental deposit will be charged to the account the next time the account is billed. T

i. Satisfactory payment history is defined as paying all bills by due date, having no disconnections for nonpayment, having no defaulted credit arrangements, having no returned payments and having no meter diversion or theft of service.

ii. A nonresidential customer does not maintain satisfactory credit criteria when its credit score at any national independent credit rating service falls to a level that is deemed to present a risk of nonpayment, including but not limited to: below a "BB+" level at Standard and Poor's or below "Ba1" at Moody's. If a nonresidential customer is not rated by a national independent credit rating service, its credit may be evaluated by using credit scoring services, public record financial information, or financial scoring and modeling services, and if it is deemed that the customer presents a risk of nonpayment, a deposit may be required.

E. Recalculation of Customer Deposit

When a deposit is held longer than 18 months, the Customer may request that the deposit be recalculated based on the Customer's actual usage. If the amount of deposit on the account differs from the recalculated amount by more than $10.00 for a residential Customer or 10 percent for a non-residential Customer, the Company may collect any underpayment and shall refund any overpayment. No refund will be made if the Customer's bill is delinquent at the time of the recalculation.

5. Payments

Bills will be rendered by the Company to the Customer monthly or in accordance with the tariff selected applicable to the Customer's service.

A. Equal Payment Plan (Budget)

Nonresidential customers with accounts that are current and that maintain satisfactory credit criteria per paragraph 4(D) above and all residential customers have the option of paying a fixed amount each month under the Company's Equal Payment Plan. The monthly payment amount will be based on one-twelfth of the Customer's estimated annual usage. The payment amount is subject to periodic review and adjustment during the budget year to more accurately reflect actual usage. The normal plan period is 12 months, which may commence April through December.

Continued on Sheet 2-4

Terms and Conditions of Service Continued

Equal Payment Plan (Budget) Continued T

In the last month of the plan (the "settle-up month") if the actual usage during the plan period exceeds the amount billed, the Customer will be billed for the balance due. If an overpayment exists, the amount of overpayment will either be refunded to the Customer or credited to the last bill of the period. If a Customer discontinues service with the Company under the Equal Payment Plan, any amounts not yet paid shall become payable immediately.

If a Customer fails to pay bills as rendered under the Equal Payment Plan, the Company reserves the right to revoke the plan, restore the Customer to regular billing, require immediate payment of any deficiency, and require a cash deposit or other guaranty to secure payment of bills.

Customers currently enrolled in the Equal Payment Plan whose settle-up month falls within the period December through February may elect to change their settle-up month to November or March if their Equal Payment Plan account is current.

If a customer who is currently enrolled in the Equal Payment Plan elects to take service under Tariff N.M.S. II, such customer will be removed from the Equal Payment Plan and restored to regular billing. Additionally, if a customer who is currently enrolled in the Equal Payment Plan elects to take service under Tariff FlexPay, such customer will be removed from the Equal Payment Plan and billed on a pay as they use basis. T

B. Average Monthly Payment Plan

The Average Monthly Payment Plan (AMP Plan) is available to all residential customers and nonresidential customers with accounts that are current and that maintain satisfactory credit criteria per paragraph 4(D) above.

The AMP Plan is designed to allow the Customer to pay an average amount each month based upon the actual billed amounts during the past twelve (12) months. The average payment amount is based upon the current month's total bill plus the eleven (11) preceding months. That result is divided by the total billing days associated with the billings to determine a per day average. The daily average amount is multiplied by thirty (30) to determine the current month's payment under the AMP Plan. At the next billing period, the oldest month's billing history is removed, the current month's billing is added and the total is again divided by the total billing days associated with the billings to determine a per day average. Again the daily average amount is multiplied by thirty (30) to find the new average payment amount. The average monthly payment amount is calculated each and every month in this manner.

If a customer who is currently enrolled in the AMP Plan elects to take service under Tariff N.M.S. II, such customer will be removed from the AMP Plan and restored to regular billing. Additionally, if a customer who is currently enrolled in the AMP Plan elects to take service under Tariff FlexPay, such customer will be removed from the AMP Plan and billed on a pay as they use basis. T

Continued on Sheet 2-5

Terms and Conditions of Service Continued

Average Monthly Payment Plan Continued T

The difference between the actual billings and the AMP Plan billings will be carried in a deferred balance. Both the debit and credit differences will accumulate in the deferred balance for the duration of the AMP Plan year, which is twelve (12) consecutive billing months. At the end of the AMP Plan year (anniversary month), the current month's billing plus the eleven (11) preceding month's billing is summed and divided by the total billing days associated with the billings to determine a per day average. That result is multiplied by thirty (30) to calculate the AMP Plan's monthly payment amount. In addition, the net accumulated deferred balance is divided by 12. This result is added or subtracted to the calculated average payment amount starting with the next billing of the new AMP plan year and will be used in the average payment amount calculation for the remaining AMP plan year. Settlement occurs only when participation in the AMP Plan is terminated. This happens if any account is final billed, if the customer requests termination, or at the Company's discretion when the customer fails to make two or more consecutive monthly payments on an account by the due date. The deferred balance (debit or credit) is then applied to the billing now due.

In such instances where sufficient billing history is not available, an AMP Plan may be established by using the actual billing history available throughout the first AMP Plan year.

C. All Payments

All bills are due and payable within twenty-one (21) days after their mailing date. Failure to receive a bill will not entitle a Customer to any discount or to the remission of any charges for non-payment within the time specified. The word "month" as used herein and in the tariffs is hereby defined to be the elapsed time between 2 successive meter readings approximately 30 days apart.

In the event of the stoppage of or the failure of any meter to register the full amount of energy consumed, the Customer will be billed for the period based on an estimated consumption of energy in a similar period of like use.

Delayed Payment Charge

The tariffs of the Company are met if the account of the Customer is paid within the time limit specified in the tariff applicable to the Customer's service. Residential customers are not subject to a delayed payment charge. On all non-residential accounts not so paid, an additional charge of 5% of the unpaid balance will be applied. Any one delayed payment charge billed against the Customer for non-payment of bill or any one forfeited discount applied against the Customer for non-payment of bill may be remitted, provided the Customer's previous accounts are paid in full and provided no delayed payment charge or forfeited discount has been remitted under this clause during the preceding six months. T

6. Payment Arrangements

In accordance with 807 KAR 5:006 Section 14(2), Kentucky Power shall negotiate and accept reasonable payment arrangements at the request of a residential customer who has received a termination notice for failure to pay. Payment arrangements will include the following reasonable provisions:

a. Partial Payment Plans are available up to the day prior to the termination date printed on a customer's termination notice.
b. Partial Payment Plans are available only for current balances and balances up to 30 days in arrears.
c. Any balance more than 30 days in arrears must be paid in full at least one business day prior to the date the Partial Payment Plan is established.
d. Customers with delinquent or otherwise unsatisfied Partial Payment Plans may not be eligible for a Partial Payment Plan.

Continued on Sheet 2-6

Terms and Conditions of Service Continued

Payment Arrangements Continued T

e. Unpaid deposit amounts are not eligible for inclusion in a Partial Payment Plan.
f. Company reserves the right to refuse unverifiable third-party pledges toward a customer's obligations under a Partial Payment Plan.
g. Customer shall be advised, in writing or by telephone, the date and the amount of payment(s) due. Service may be terminated without additional notice if the Customer fails to meet the obligations of the agreed plan.
h. It is the responsibility of the customer presenting the Medical Certificate to contact the Company to negotiate a payment arrangement based upon the customer's ability to pay. The payment arrangement shall require that the account become current no later than October 15.
i. Customers presenting Certification from the Cabinet for Health and Family Services must do so during the initial 10 day termination notice period. As a condition of the 30-day extension, the customer shall exhibit good faith by entering into a payment arrangement.

7. Underground Service

When a real estate developer desires an underground distribution system within the property which he is developing or when a Customer desires an underground service, the real estate developer or the Customer as the case may be, shall pay the Company the difference between the anticipated cost of the underground facilities so requested and the cost of the overhead facilities which would ordinarily be installed in accordance with 807 KAR 5:041, Section 21, and the Company's underground service plan as filed with the Public Service Commission. Upon receipt of payment, the Company will install the underground facilities and will own, operate and maintain the same.

Please see Tariff Sheet No. 14-1 for the underground differential cost schedule.

8. Company's Liability

The Company will use reasonable diligence in furnishing a regular and uninterrupted supply of energy, but does not guarantee uninterrupted service. The Company shall not be liable for damages in case such supply should be interrupted or fail by reason of an event of Force Majeure. Force Majeure consists of an event or circumstance which prevents Company from providing service, which event or circumstance was not anticipated, which is not in the reasonable control of, or the result of negligence of, the Company, and which, by the exercise of due diligence, Company is unable to overcome or avoid or cause to be avoided. Force Majeure events includes acts of God, the public enemy, accidents, labor disputes, orders or acts of civil or military authority, breakdowns or injury to the machinery, transmission lines, distribution lines or other facilities of the Company, or extraordinary repairs.

Unless otherwise provided in a contract between the Company and Customer, the point at which service is delivered by Company to Customer, to be known as "delivery point," shall be the point at which the Customer's facilities are connected to the Company's facilities. The metering device is the property of the Company. The meter base, connection, grounds and all associated internal parts inside the meter base are customer owned and are the responsibility of the customer to install and maintain. The Company shall not be liable for any loss, injury, or damage resulting from the Customer's use of their equipment or occasioned by the energy furnished by the Company beyond the delivery point.

Any new installation, upgrade or other modification of an existing meter installation shall be made using only Company-supplied or Company-approved meter bases. A list of Company-approved meter bases and specifications can be found on the Company's website at: www.kentuckypower.com.

Continued on Sheet 2-7

Terms and Conditions of Service Continued

Company's Liability Continued

The Customer shall provide and maintain suitable protective devices on their equipment to prevent any loss, injury or damage that might result from single phasing conditions or any other fluctuation or irregularity in the supply of energy. The Company shall not be liable for any loss, injury or damage resulting from a single phasing condition or any other fluctuation or irregularity in the supply of energy which could have been prevented by the use of such protective devices. The Company shall not be liable for any damages, whether direct, incidental or consequential, including, without limitation, loss of profits, loss of revenue, or loss of production capacity occasioned by interruptions, fluctuations, or irregularity in the supply of energy.

The Company is not responsible for loss or damage caused by the disconnection or reconnection of its facilities. The Company is not responsible for loss or damages caused by the theft or destruction of Company facilities by a third party.

The Company will provide and maintain the necessary line or service connections, transformers (when same are required by conditions of contract between the parties thereto), meters and other apparatus, which may be required for the proper measurement of and protection to its service. All such apparatus shall be and remain the property of the Company.

9. Customer's Liability

In the event of loss or injury to the property of the Company through misuse by, or the negligence of, the Customer or the employees of the same, the cost of the necessary repairs or replacement thereof shall be paid to the Company by the Customer.

Customers will be responsible for tampering with, interfering with, or breaking the seals of meters, or other equipment of the Company installed on the Customer's premises. The Customer hereby agrees that no one except the employees of the Company shall be allowed to make internal or external adjustments to any meter or any other piece of apparatus, which shall be the property of the Company.

The Company shall have the right at all reasonable hours to enter the premises of the Customer for the purpose of installing, reading, removing, testing, replacing or otherwise disposing of its apparatus and property, and the right of entire removal of the Company's property in the event of the termination of the contract for any cause. The Company may assess charges based on electric usage and damages to all Company equipment.

10. Extension of Service

The electric facilities of the Company shall be extended or expanded to supply electric service to all residential Customers and small commercial Customers which require single phase line where the installed transformer capacity does not exceed 25 KVA in accordance with 807 KAR 5:041, Section 11.

The electric facilities of the Company shall be extended or expanded to supply electric service to Customers other than those named in the above paragraph when the estimated revenue is sufficient to justify the estimated cost of making such extensions or expansions as set forth below.

Continued on Sheet 2-8

Terms and Conditions of Service Continued

Extension of Service Continued

For services to be delivered to Commercial, Industrial, Mining and multiple housing project Customers up to and including estimated demands of 500 KW requiring new facilities, the Company will: (a) where the estimated revenue for one year exceeds the estimated installed cost of new local facilities required, provide such new facilities at no cost to the Customer; (b) where the estimated revenue for one year is less than the installed cost of new local facilities required, the Customer will be required to pay a contribution in aid of construction equal to the difference between the installed cost of the new facilities required to service the load and the estimated revenue for one year; (c) if the Company has reason to question the financial stability of the Customer and/or the life of the operation is uncertain or temporary in nature, such as construction projects, oil and gas well drilling, sawmills and mining operations, the Customer shall pay a contribution in aid of construction, consisting of the estimated labor cost to install and remove the facilities required plus the cost of unsalvageable material, before the facilities are installed.

For service to be delivered to Customers with demand levels higher than those specified above, the annual cost to serve the Customer's requirements shall be compared with the estimated revenue for one year to determine if a contribution in aid of construction, and/or a special minimum and/or other arrangement may be necessary. The annual cost to serve shall be the sum of the following components:

i. The annual fixed costs of the generation, transmission and distribution facilities related to the Customer's requirements. These fixed costs will be calculated at 21.95% of the value to be based on the year-end embedded investment depreciated in all similar facilities of the Company.
ii. The annual energy cost based on the latest available production costs related to the Customer's estimated annual energy use requirements.
iii. The annual fixed costs of the new local facilities necessary to provide the service requested calculated at 21.95% of the installed cost of such facilities.

If the estimated revenue for one year is greater than the cost to serve as describe herein, the Company may provide any new local facilities required at no cost to the Customer. If the estimated revenue for one year is less than the cost to serve as described herein, the Company will require the Customer to pay a contribution in aid of construction equal to the difference between the annual cost to serve as calculated and the estimated revenue for one year divided by 21.95%, but in no case to exceed the installed cost of the new facilities required. If, however, the annual cost to serve excluding the cost of new facilities paid for by the Customer exceeds the estimated revenue for one year, the Company, will, in addition to a contribution in aid of construction, require a special minimum or other arrangement to compensate the Company for such deficiency in venue.

Except where service is rendered in accordance with 807 KAR 5:041, Section 11, as described herein, the Company may require the Customer to execute an Advance and Refund Agreement where the Company reasonably questions the longevity of the service or the estimated energy use and demand requirements provided by the Customer. Under the Advance and Refund Agreement, the Customer shall pay the company the estimated total installed cost of the required new facilities which advance could be refunded over a five year period under certain circumstances. Over the five year period the Customer' electric bill would be credited each month up to the amount of 1/60th of the total amount advanced.

11. Extension of Service to Mobile Home

The electrical facilities of the Company will be extended or expanded to supply electric service to mobile homes in accordance with 807 KAR 5:041, Section 12.

Continued on Sheet 2-9

Terms and Conditions of Service Continued

12. Location and Maintenance of Company Equipment

The Company shall have the right to construct its poles, lines and circuits on the property, and to place its transformers and other apparatus on the property or within the building of the Customer, at a point or points convenient for such purposes, as required to serve such Customer, and the Customer shall provide suitable space for the installation of necessary measuring instruments so that the latter may be protected from injury by the elements or through the negligence or deliberate acts of the Customer or of any employee of the same.

13. Billing Form

Pursuant to 807 KAR 5:006, Section 7, copies of the billing forms used by the Company are shown on Sheet Nos. 2-17 thru 2-26. T

14. Rate Schedule Selection

The Company will explain to the Customer, at the beginning of service or upon request, the Company's rates available to the Customer. Company will assist Customer in the selection of the rate schedule best adapted to Customer's service requirements, provided, however, that Company does not assume responsibility for the selection or that Customer will at all times be served under the most favorable rate schedule.

Customer may change their initial rate schedule selection to another applicable rate schedule at any time by either written notice to Company and/or by executing a new contract for the rate schedule selected, provided that the application of such subsequent selection shall continue for 12 months before any other selection may be made. In no case will the Company refund any monetary difference between the rate schedule under which service was billed in prior periods and the newly selected rate schedules.

15. Monitoring Usage

At least once quarterly the Company will monitor the usage of each customer according to the following procedure:

a. The Customer's monthly usage will be compared with the usage of the corresponding period of the previous year.
b. If the monthly usage for the two periods is substantially the same or if any difference is known to be attributed to unique circumstances, such as unusual weather conditions, common to all customers, no further review will be made.
c. If the monthly usage is not substantially the same and cannot be attributed to a readily identified common cause, the Company will compare the Customer's monthly usage records for the 12-month period with the monthly usage for the same months of the preceding year.
d. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, the company will contact the Customer to determine whether there have been changes that explain the increased or decreased usage.
e. Where the deviation is not otherwise explained, the Company will test the Customer's meter to determine whether it shows an average error greater than 2 percent fast or slow.
f. The Company will notify the Customer of the investigation, its findings, and any refunds or back billing in accordance with 807 KAR 5:006, Section 11(4) and (5).

In addition to the quarterly monitoring, the Company will immediately investigate usage deviations brought to its attention as a result of its on-going meter reading, billing processes, or customer inquiry.

Continued on Sheet 2-10

Terms and Conditions of Service Continued

16. Use of Energy by Customer

The tariffs for electric energy given herein are classified by the character of use of such energy and are not available for service except as provided herein.

Upon the expiration of an electric service contract, if required by the terms of the tariff, the Customer may elect to renew the contract upon the same or another tariff published by the Company available to the Customer and applicable to the Customer's requirements, except that in no case shall the Company be required to maintain transmission, switching or transformation equipment different from or in addition to that generally furnished to other Customers receiving electrical supply under the terms of the tariff elected by the Customer.

The service connections, transformers, meters and appliances supplied by the Company for each Customer have a definite capacity and no additions to the equipment, or load connected thereto, will be allowed except by consent of the Company.

D

The Customer shall install only motors, apparatus or appliances which are suitable for operation with the character of the service supplied by the Company, and which shall not be detrimental to same, and the electric energy must not be used in such a manner as to cause unprovided-for voltage fluctuations or disturbances in the Company's transmission or distribution system. The Company shall be the sole judge as to the suitability of apparatus or appliances, and also as to whether the operation of such apparatus or appliances is or will be detrimental to its general service.

No attachment of any kind whatsoever may be made to the Company's lines, poles, cross arms, structures or other facilities without the express written consent of the Company.

All apparatus used by the Customer shall be of such type as to secure the highest practicable commercial efficiency, power factor and the proper balancing of phases. Motors which are frequently started or motors arranged for automatic control must be of a type to give maximum starting torque with minimum current flow, and must be of a type, and equipped with controlling devices, approved by the Company. The Customer agrees to notify the Company of any increase or decrease in his connected load

The Company will not supply service to Customers who have other sources of electrical energy supply except under tariffs that specifically provide for same.

The Customer shall not be permitted to operate generating equipment in parallel with the Company's service except with express written consent of the Company.

Resale of energy will be permitted only with express written consent by the Company.

17. Residential Service

Except as otherwise provided in these tariffs, individual residences shall be served individually with single-phase secondary service under the applicable residential service tariff. Customer may not take service for 2 or more separate residences through a single point of delivery under any tariff. Exclusions may be allowed pursuant to 807 KAR 5:046 (Prohibition of master metering).

Continued on Sheet 2-11

Terms and Conditions of Service Continued

Residential Service Continued T

The residential service tariff shall cease to apply to that portion of a residence which becomes regularly used for business, professional, institutional or gainful purposes, which requires three phase service or primary service or which requires service to motors in excess of 10 HP each. Under these circumstances, Customer shall have the choice of: (1) separating the wiring so that the residential portion of the premises is served through a separate meter under the residential service tariff, and the other uses as enumerated above are served through a separate meter or meters under the applicable general service tariff; or (2) taking the entire service under the applicable general service tariff.

Detached building or buildings, actually appurtenant to the residence, such as a garage, stable or barn, may be served by an extension of the Customer's residence wiring through the residence meter and under the applicable residential service tariff.

18. Denial or Discontinuance of Service

The Company reserves the right to refuse or discontinue service to any customer if the customer is indebted to the Company for any service theretofore rendered at any location. Service will not be supplied or continued to any premises if at the time of application for service the Applicant is merely acting as an agent or person or former customer who is indebted to the Company for service previously supplied at the same, or other premises, until payment of such indebtedness shall have been made.

D

Unpaid balances of previously rendered Final Bills may be transferred to any account for which Customer has responsibility and may be included on initial or subsequent bills for the account to which the transfer was made. Such transferred Final Bills, if unpaid, will be a part of the past due balance of the account to which they are transferred. When there is no lapse in service, such transferred Final Bills will be subject to Company's collections and disconnect procedures in accordance with 807 KAR 5:006, Section 15(1)(f). Final Bills transferred following a lapse in service will not be subject to disconnection unless: (1) such service was provided pursuant to a fraudulent application submitted by Customer; (2) Customer and Company have entered into a contractual agreement which allows for such a disconnection; or (3) the current account is subsequently disconnected for service supplied at that point of delivery, at which time, all unpaid and past due balances must be paid prior to reconnect.

Residential disconnections are limited to the hours of 8:00 a.m. through 5:00 p.m. Monday through Thursday and 8:00 a.m. through noon on Friday.

Residential service will not be disconnected for 24 hours following when temperatures are forecast to be 32 degrees or below or 95 degrees or higher.

Continued on Sheet 2-12

Terms and Conditions of Service Continued

19. Special Charges

a. Reconnection and Disconnect Charges

In cases where the Company has discontinued service as herein provided for, the Company reserves the right to assess a reconnection charge pursuant to 807 KAR 5:006, Section 9 (3)(b), payable in advance, in accordance with the following schedule. However, those Customers qualifying for Winter Hardship Reconnection under 807 KAR 5:006 Section 16 shall be exempt from the reconnect charges.

Reconnect for nonpayment during regular hours for non-remote reconnection meters	$54.11	I T
Reconnect at the end of the day (no "Call Out" required) for non-remote reconnection meters	$137.20	
Reconnect for nonpayment when a "Call Out" is required prior to 8:00 p.m. for non-remote reconnection meters (A "Call Out" is when an employee must be called in to work on overtime basis to make the reconnect trip. Reconnection for nonpayment will not be made when a "Call Out" after 8:00 p.m. is required)	$137.20	
Reconnect for nonpayment when double time is required (Sunday and Holiday) for non-remote reconnection meters	$178.75	T
Reconnect for nonpayment for meters with remote reconnection capability	$0.00	N
Termination or field trip	$54.11	I

The reconnection charge for all Customers where service has been disconnected for fraudulent use of electricity will be the actual cost of the reconnection.

b. Meter Read Check

Pursuant to 807 KAR 5:006, Section 9(3)(d) in cases where a customer requests a meter be reread, and the second reading shows the original reading was correct, the Customer will be charged a fee of $54.11 to cover the handling cost. I

c. Returned Check Charge

In cases where a customer pays by check, which is later returned as unpaid by the bank for any reason, the Customer will be charged a fee of $6.60 to cover the handling costs. R

d. Meter Test Charge

Where test of a meter is made upon written request by the Customer pursuant to 807 KAR 5:006, Section 19, the Customer will be charged $74.88 if such test shows that the meter was not more than two percent (2%) fast. I

e. Work Performed on Company's Facilities at Customer's Request

Whenever, at the request and for the benefit of the Customer, work is performed on the Company's facilities, including the relocation, or replacement of the Company's facilities, the Customer shall pay to the Company in advance of the Company undertaking the work the estimated total cost of such work. This cost shall be itemized by major categories and shall include the Company's overheads and shall be credited with the net value of any salvageable material. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the Customer.

Continued on Sheet 2-13

Terms and Conditions of Service Continued

Special Charges Continued

Reasonable notice of not less than three working days shall be given to the Company for all requested work except for the covering of the Company's lines. Notice of any request for the Company to cover its lines shall be given at least two days in advance. The Company will endeavor to comply with all timely requests, but work may be delayed because of demands on the Company's personnel and equipment.

If the cost, as calculated above, is $500 or less for covering the Company's distribution facilities no charge will be imposed. All costs in excess of $500 for covering the Company's distribution facilities shall be paid by the Customer, in advance of the Company undertaking the work. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the customer.

20. Refunds to Residential Customers

The Company may make a refund to residential customers by one of the following means: a credit to the Customer's bill, a prepaid card, or a check or electronic funds transfer (EFT).

The Company acting through its customer service representative shall fully address and resolve any customer complaints or disputes related to: (a) the accuracy of the names and last known addresses of the customer to receive prepaid cards; (b) the effective delivery and receipt of the prepaid cards; and (c) the amount of any refunds.

21. Alerts and Subscriptions

Kentucky Power offers an optional Mobile Alert Service for customers through which participating customers can elect to receive notifications from the Company via e-mail or text message. The Company provides billing and payment alerts and alerts relating to outages. These alerts are supplemental to standard communications from the Company and to the extent any discrepancies exist between the information contained in the mobile alerts and the information contained in standard communications from the Company, the information in the standard communications from the Company shall prevail.

Customers interested in receiving mobile alerts from Kentucky Power may sign up for the service through the Company's website at www.kentuckypower.com. The full terms and conditions of participating in the Kentucky Power Mobile Alert Service are included on the Company's website. Customers wishing to participate in Kentucky Power's Mobile Alert Service and to receive alerts via e-mail should add communications@kentuckypower-aep.com and communications@aep-email.com to the customer's email address book or spam filter to avoid alert communications from Kentucky Power being directed to spam. Customers are advised to contact their e-mail service provider for instructions on how to add addresses to an address book or spam filter if needed. T

E-mail addresses from which alerts are sent through the Mobile Alert Service are used for sending e-mails only. Any e-mails sent to those addresses will not be received by the Company and the Company will not respond. Any electronic communication to the Company should be sent to Communications@kentuckypower-mail.com.

There is no charge from the Company for the Mobile Alert Service; however, message and data rates may apply. Customers are advised to verify message and data rates with their cellular and internet service providers.

Information regarding the types of alerts and the Mobile Alert Service in general are provided below.

Continued on Sheet 2-14

Terms and Conditions of Service Continued

Alerts and Subscriptions Continued

Billing and Payment Alerts

Billing and payment alerts provided through Kentucky Power's Mobile Alert Service are in addition to regular billing statements, payment notifications, disconnect notices, or other standard communications sent by Kentucky Power or its third party partners as required by law, regulation, or tariff filed by Kentucky Power or its subsidiaries. These alerts are not a replacement for any regular billing statement, payment notifications, disconnect notices, or other standard communications. In the event of a discrepancy between the information provided in a billing or payment alert provided through the Mobile Alert Service and the information provided in the Company's standard communication, the information in the standard communication shall prevail.

Kentucky Power shall not have any liability for any delay or failure to deliver a billing or payment alert or for any mistakes or errors in any billing or payment alert provided through the Mobile Alerts Service.

Outage Alerts

Kentucky Power provides alerts relating to system outages through its Mobile Alert Service. Outage alerts will be sent when the Company has evidence of an outage at a subscribed address. Due to variations in equipment from one area to another, it is possible that the accuracy of outage alerts will vary from one area to another. Recipients shall consider any outage related information as guidance and not as an absolute guarantee. Kentucky Power will send outage related notifications based upon available information and does not guarantee that the notifications will be without error.

Planned outages and short-duration outages will normally not generate an outage-related notification. During large-scale outage events, the frequency and timeliness of outage updates may be impacted.

Kentucky Power shall not have any liability for any delay or failure to deliver an outage-related notification.

General

Kentucky Power does not warrant or guarantee that alerts will be sent or received, and Kentucky Power shall not be responsible for any lost or misdirected messages.

Customers electing to participate in Kentucky Power's Mobile Alert Service authorize the Company to contact them via their elected communication method with transactional messages pertaining to the service. Participation in the Mobile Alert Service shall be considered as affirmative consent to receive the related messages should these messages ever be classified as commercial in nature.

Kentucky Power shall not have any liability under any theory of recovery, whether in contract or tort, for any loss or damages due to delay or failure to deliver an alert through the Mobile Alert Service. Without limiting the previous sentence, Kentucky Power disclaims any liability, expressed or implied, for indirect or consequential damages arising from a customer's subscription to Kentucky Power's Mobile Alert Service.

Customer agrees not to publish, copy, communicate to the public, edit, retransmit, or amend any data received as part of Kentucky Power's Mobile Alert Service. The data communicated via the Mobile Alert Service is provided for the participating customer's personal non-commercial use only and may not be used for any other purpose.

Continued on Sheet 2-15

Terms and Conditions of Service Continued

Alerts and Subscriptions Continued

Personal information and data ("Personal Data") provided by customers when using Kentucky Power's Mobile Alert Service will only be used by Kentucky Power and its suppliers and contractors for Mobile Alert Service-related purposes. Data other than Personal Data may be aggregated and used by the Company for the purpose of undertaking market research or in facilitating reviews, developments and improvements to Kentucky Power's Mobile Alert Service.

Customers participating in the Mobile Alert Service may discontinue a portion of or all alerts at any time by modifying their alert subscription or by unsubscribing entirely. Customers wishing to modify or unsubscribe from the Mobile Alert Service may do so at the Company's website: www.kentuckypower.com or by contacting Kentucky Power's Customer Operations Centers at 1-800-572-1113. Kentucky Power will process a request to unsubscribe from the Mobile Alert Service within ten days of receiving the request. Kentucky Power is authorized to send a communication to a customer requesting to unsubscribe from the Mobile Alert Service to confirm the request.

The terms and conditions the Company's Mobile Alert Service shall be governed by applicable state law.

Customers electing to participate in the Company's Mobile Alert Service agree to the terms and conditions of the service and further agree that the terms and conditions may be updated from time to time. The Company will provide customers participating in the Mobile Alert Service with updated terms and conditions as they become effective. Customers participating in the Mobile Alert Service must take affirmative action to withdraw from the service if the customer does not agree with any new or updated term or condition of service. Failure to withdraw after an updated term and condition is provided by the Company means that the customer accepts the new or updated terms and conditions.

Additional Terms and Conditions for E-mail Alerts
If a customer sends an email to Kentucky Power with questions or comments, Kentucky Power may use the customer's e-mail address and other personal information included in the correspondence in order to respond. If a customer provides the Company with an e-mail address in order to receive alerts, Kentucky Power may use that e-mail address to send the customer other types of information.

A customer may unsubscribe from receiving e-mail alerts by clicking the "Unsubscribe" link near the bottom of an e-mail alert.

Additional Terms and Conditions for Text Message Alerts
Customers may elect to receive text alerts through Kentucky Power's Mobile Alert Service. For text alerts, message and data rates may apply consistent with the customer's mobile phone service agreement. Kentucky Power assumes no responsibility for any service charges received from customer's mobile phone service providers for text alerts received through the Mobile Alert Service. Kentucky Power is not responsible for and will not be liable for any breach of the terms of an agreement between a customer electing to receive text alerts through the Mobile Alert System and that customer's mobile phone service provider or for any mistake that may arise in the billing process.

To receive text alerts from the Company through the Mobile Alert Service, the customer must be the owner or legitimate user of the mobile phone registered or have the express consent of the owner or legitimate user. Customers electing to receive text alerts from the Company through the Mobile Alert Service are responsible for providing and maintaining a mobile phone and ensuring connection to a mobile network capable of receiving the text alerts.

Continued on Sheet 2-16

Terms and Conditions of Service Continued

Alerts and Subscriptions Continued T

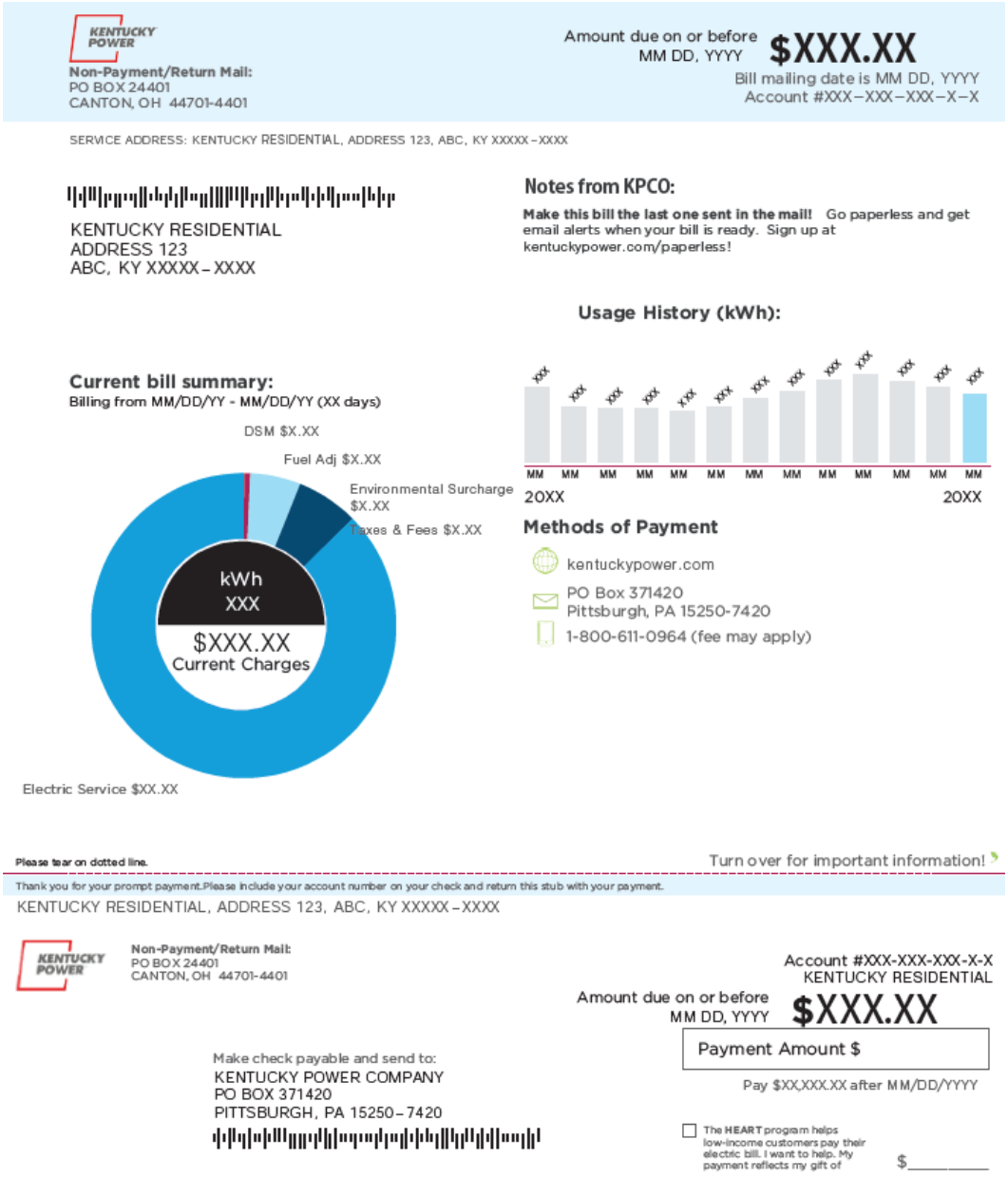
Customers electing to receive text alerts through the Mobile Alert Service acknowledge that the text alerts may, at any time, be adversely affected by problems with the mobile phone network including, without limitation, interference to the network coverage. Kentucky Power shall not be responsible or liable for any loss, damage, or expense incurred directly or indirectly by customers electing to receive text alerts through the Mobile Alert Service as a result of any difficulties experienced by any cellular phone service provider.

In the event a customer electing to receive text alerts through the Mobile Alert Service changes mobile phone service providers or telephone number, that customer is required to subscribe again to receive text alerts. If no alerts are sent or received for eighteen months, a customer's opt-in to that offering will expire. A customer must opt-in again to the program in order to receive alerts.

Kentucky Power may discontinue text alerts at any time. Customers electing to receive text alerts through the Mobile Alert Service will receive text alerts from 23711. Customers may unsubscribe from text alerts by texting STOP to 23711 and may obtain assistance via text by texting HELP to 23711.

Continued on Sheet 2-17

Terms and Conditions of Service Continued



Continued on Sheet 2-18

Terms and Conditions of Service Continued

KENTUCKY POWER

Service Address:

KENTUCKY RESIDENTIAL
ADDRESS 123
ABC, KY XXXXX–XXXX
Account #XXX-XXX-XXX-X-X

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XXX.XX
Payment 02/07/22 - Thank You		-XXX.XX
Previous Balance Due	**$**	X.XX
Current KPCO Charges		
Tariff XXX - Residential Service XX/XX/XX		
Rate Billing	$	XXX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-XX.XX
Fuel Adj @ X.XXXXX Per kWh		XX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
DSM Adj @ X.XXXXX Per kWh		XX.XX
Residential Energy Assistance @ $X.XX		XX.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Renewable Power Option Rider		XX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Generation Rider $X.XXXXX/kWh		XX.XX
Envrionmental Adj. X.XXXXX%		XX.XX
School Tax		XX.XX
City's Franchise Fee		XX.XX
State Sales Tax		XX.XX
Current Balance Due	**$**	XXX.XX
Homeserve Warranty Service	$	XX.XX

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
XXXXX	Actual	XXXXX	Actual	XXX	XXX kWh
Service Period XX/XX – XX/XX					Multiplier 1
Next scheduled read date should be between MM DD and MM DD .					

Notes from KPCO:

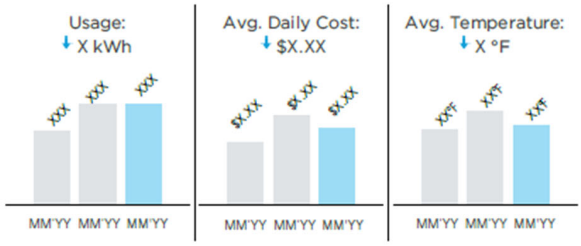
Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1–800–572–1113.

Homeserve USA is optional. Homeserve USA is not the same as KPCO and is not regulated by the KY Public Service Commission. A customer does not have to buy the Warranty Service in order to continue to receive quality regulated services from KPCO.

www.kyelectricalprotectionplan.com

Usage Details:

↑↓Values reflect changes between current month and previous month.



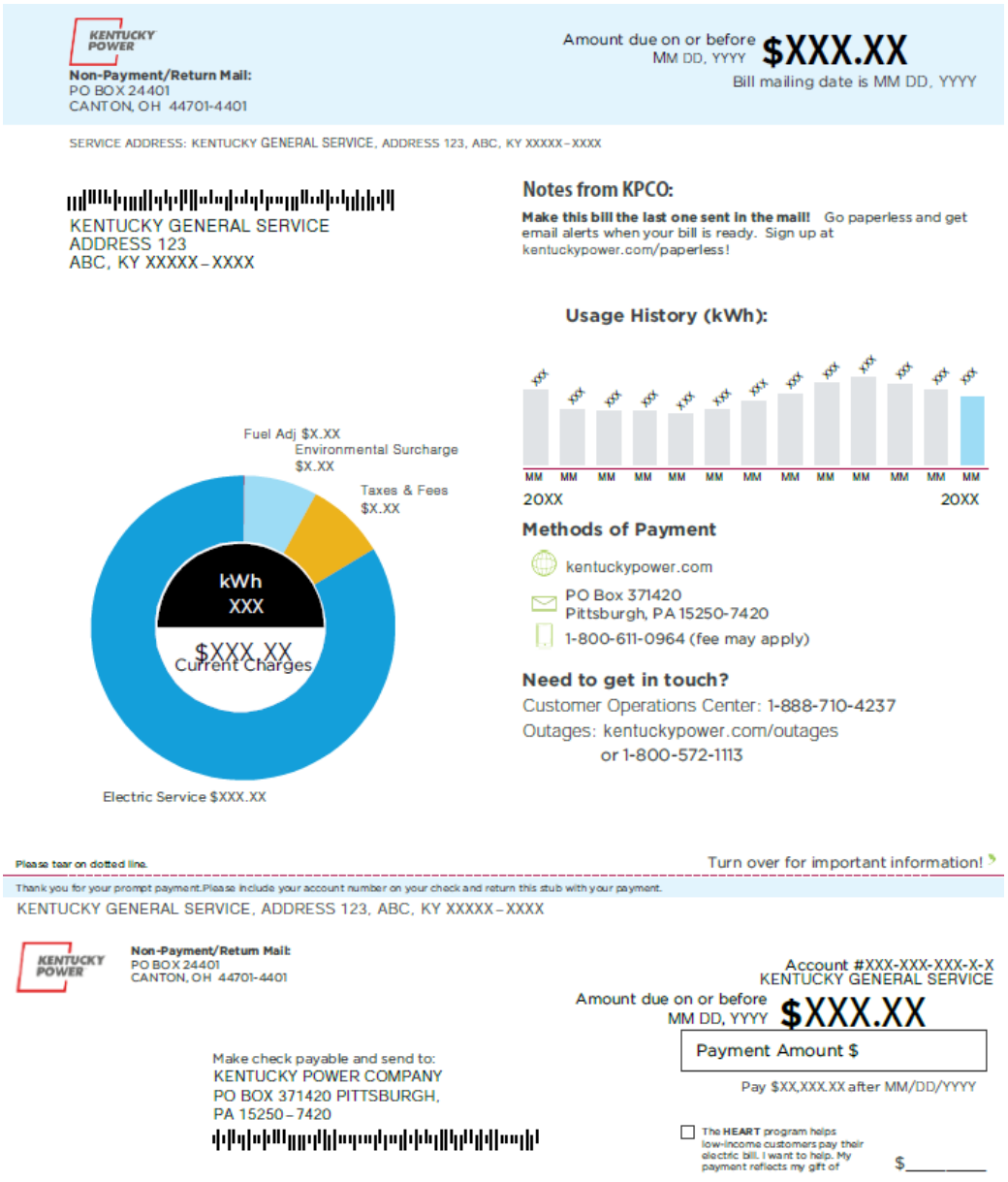
Total usage for the past 12 months: X,XXX kWh

Average (Avg.) monthly usage: XXX kWh

N

Continued on Sheet 2-19

Terms and Conditions of Service Continued



Continued on Sheet 2-20

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S.Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued

KENTUCKY POWER

Service Address:

KENTUCKY GENERAL SERVICE
ADDRESS 123
ABC, KY XXXXX – XXXX

Account #XXX-XXX-XXX-X-X

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XX.XX
Payment XX/XX/XX - Thank You		-XX.XX
Previous Balance Due	**$**	**X.XX**
Current KPCO Charges		
Tariff XXX - General Service XX/XX/XX		
Rate Billing	$	XX.XX
Demand Charge		XX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-XX.XX
Fuel Adj @ X.XXXXX Per kWh		XX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
DSM Adj @ X.XXXXX Per kWh		XX.XX
Kentucky Economic Development Surcharge @ $X.XX		XX.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Renewable Power Option Rider		XX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Generation Rider $X.XXXXX/kWh		XX.XX
Envrionmental Adj. X.XXXXX%		XX.XX
School Tax		XX.XX
City's Franchise Fee		XX.XX
State Sales Tax		XX.XX
Current Balance Due	**$**	**XX.XX**

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
XXX	Actual	XXX	Actual	XXX	XXX kWh
Service Period XX/XX - XX/XX					Multiplier 1
Next scheduled read date should be between MM DD and MM DD.					

Notes from KPCO:

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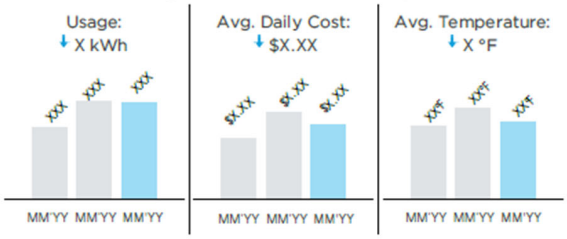
Usage Details:

↑↓Values reflect changes between current month and previous month.



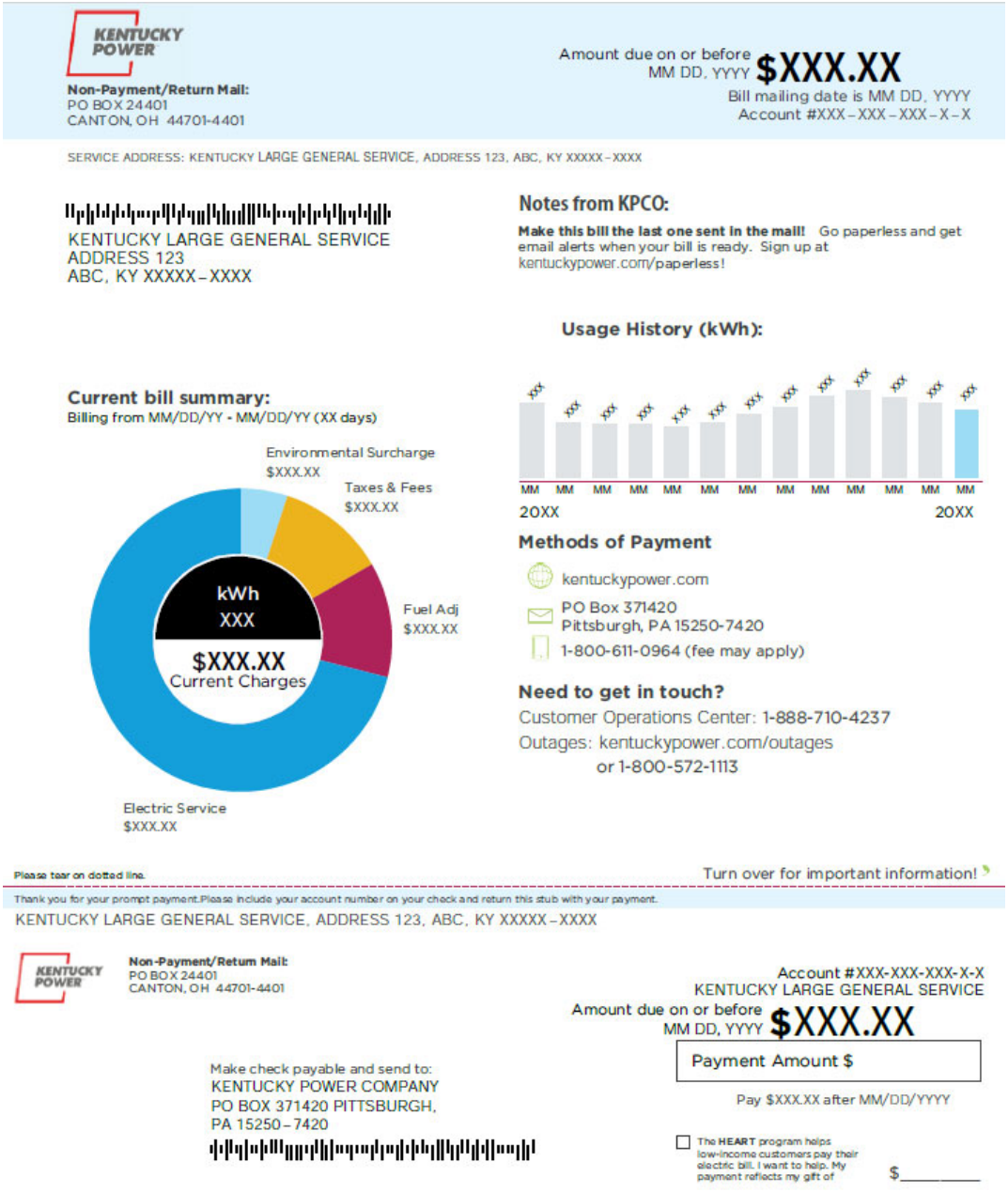
Total usage for the past 12 months: XXX kWh

Average (Avg.) monthly usage: XXX kWh

N

Continued on Sheet 2-21

Terms and Conditions of Service Continued



Continued on Sheet 2-22

DATE OF ISSUE: August 29, 2025
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ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued

KENTUCKY POWER

Service Address:

KENTUCKY LARGE GENERAL SERVICE
ADDRESS 123
ABC, KY XXXXX – XXXX
Account #XXX-XXX-XXX-X-X

Billed Usage MM/YY				
Usage	Power Factor	Power Factor Constant	Meter Location Comp.	Billed Usage
XXX	-	-	-	XXXX kWh
XXX	-	-	-	XXX kW
XXX	-	-	-	XXX.XXX KVA

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XXX.XX
Payment XX/XX/XX - Thank You		-XXX.XX
Previous Balance Due	**$**	XX.XX
Current Charges		
Tariff XXX - Large General Service XX/XX/XX		
Rate Billing	$	XXX.XX
Demand Charge		-XXX.XX
Economic Development Rider - IBDD		-XXX.XX
Economic Development Rider - SBDD		-XXX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-XXX.XX
Fuel Adj @ X.XXXXX Per kWh		XXX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
DSM Adj @ X.XXXXX Per kWh		XXX.XX
Kentucky Economic Development Surcharge @ $X.XX		X.XX
Purchased Power Adj. $X.XXXXX/kWh		XXX.XX
Renewable Power Option Rider		XXX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Generation Rider $X.XXXXX/kWh		XX.XX
Envrionmental Adj. X.XXXXX%		XXX.XX
School Tax		XXX.XX
City's Franchise Fee		XXX.XX
State Sales Tax		XXX.XX
Current Balance Due	**$**	**XXX.XX**

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
X	X	X.XXX	Actual	X	X kVAR
X	X	X.XXX	Actual	X.XXX	XXX.XX kW
XXXXX	Actual	XXXXX	Actual	XXX	XXX,XXX kWh
Service Period MM/DD - MM/DD				Multiplier XXX	
Next scheduled read date should be between MM DD and MM DD.					

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

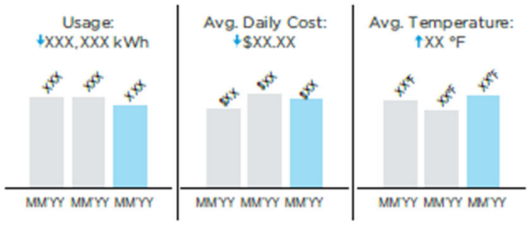
Notes from Kentucky Power:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/acclunt/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1 – 800 – 572 – 1113.

Due date does not apply to previous balance due.

Usage Details:

↑↓Values reflect changes between current month and previous month.

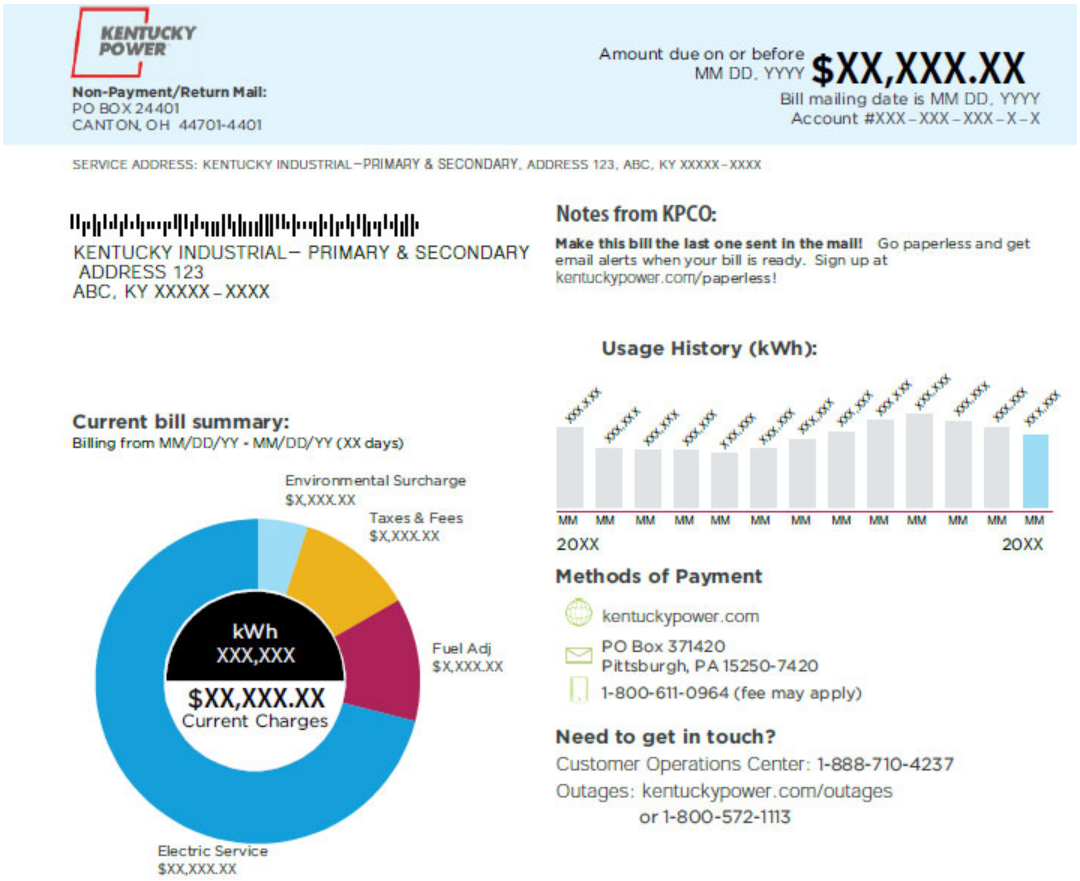


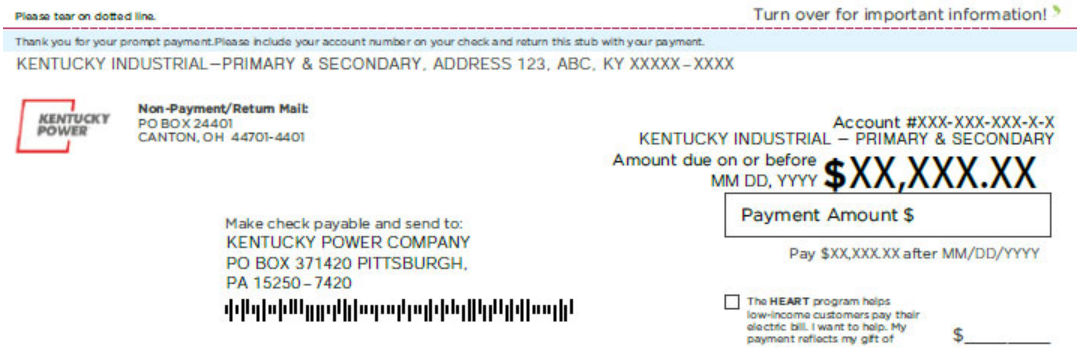
Total usage for the past 12 months: XXX kWh
Average (Avg.) monthly usage: XXX kWh

N

Continued on Sheet 2-23

Terms and Conditions of Service Continued





Continued on Sheet 2-24

T

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued

T

KENTUCKY POWER

Service Address:

KENTUCKY INDUSTRIAL–PRIMARY & SECONDARY

ADDRESS 123
ABC, KY XXXXX–XXXX

Account #XXX-XXX-XXX-X-X

Billed Usage MM/YY				
Usage	Power Factor	Power Factor Constant	Meter Location Comp.	Billed Usage
XXX.XXX	-	-	-	XXX.XXX kWh
XXX.XXX	-	-	-	XXX.XXX kW On-Pk
XXX.XXX	-	-	-	XXX.XXX kW Off-Pk
Contract Capacity = X,XXX.X				High Prev Demand = X,XXX.X On-Pk High Prev Demand = X,XXX.X Off-Pk

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XX,XXX.XX
Payment XX/XX/XX - Thank You		-XX,XXX.XX
Previous Balance Due	**$**	**XX.XX**
Current Charges		
Tariff XXX - Industrial General Service XX/XX/XX		
Rate Billing	$	XX,XXX.XX
Demand Charge		-X,XXX.XX
Economic Development Rider - IBDD		-X,XXX.XX
Economic Development Rider - SBDD		-X,XXX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-X,XXX.XX
Fuel Adj @ X.XXXXX Per kWh		X,XXX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
Kentucky Economic Development Surcharge @ $X.XX		X.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Purchased Power Adj. $X.XXXXX/kW		X,XXX.XX
Renewable Power Option Rider		X,XXX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Generation Rider $X.XXXXX/kW		XX.XX
City's Franchise Fee		X,XXX.XX
State Sales Tax		X,XXX.XX
Total Balance Due	**$**	**XX,XXX.XX**

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
X	X	X.XXX	Actual	X	X kVAR
X	X	X.XXX	Actual	X.XXX	XXX.XX kW On-Pk
XXXXX	Actual	XXXXX	Actual	XXX	XXX,XXX kWh
X	X	X.XXX	Actual	X.XX	XXX.X kW Off-Pk
X	X	X.XXX	Actual	X.XXX	XXX.XX kVAR
Service Period MM/DD - MM/DD					Multiplier XXX
Next scheduled read date should be between MM DD and MM DD.					

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

Notes from Kentucky Power:

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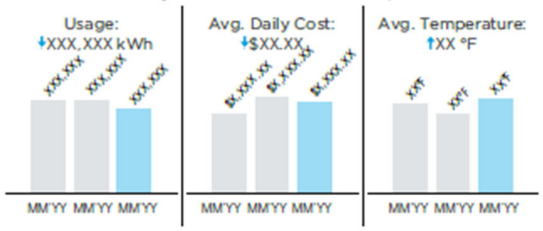
Due date does not apply to previous balance due.

Usage Details:

↑↓Values reflect changes between current month and previous month.



Total usage for the past 12 months: X,XXX,XXX kWh

Average (Avg.) monthly usage: XXX,XXX kWh

N

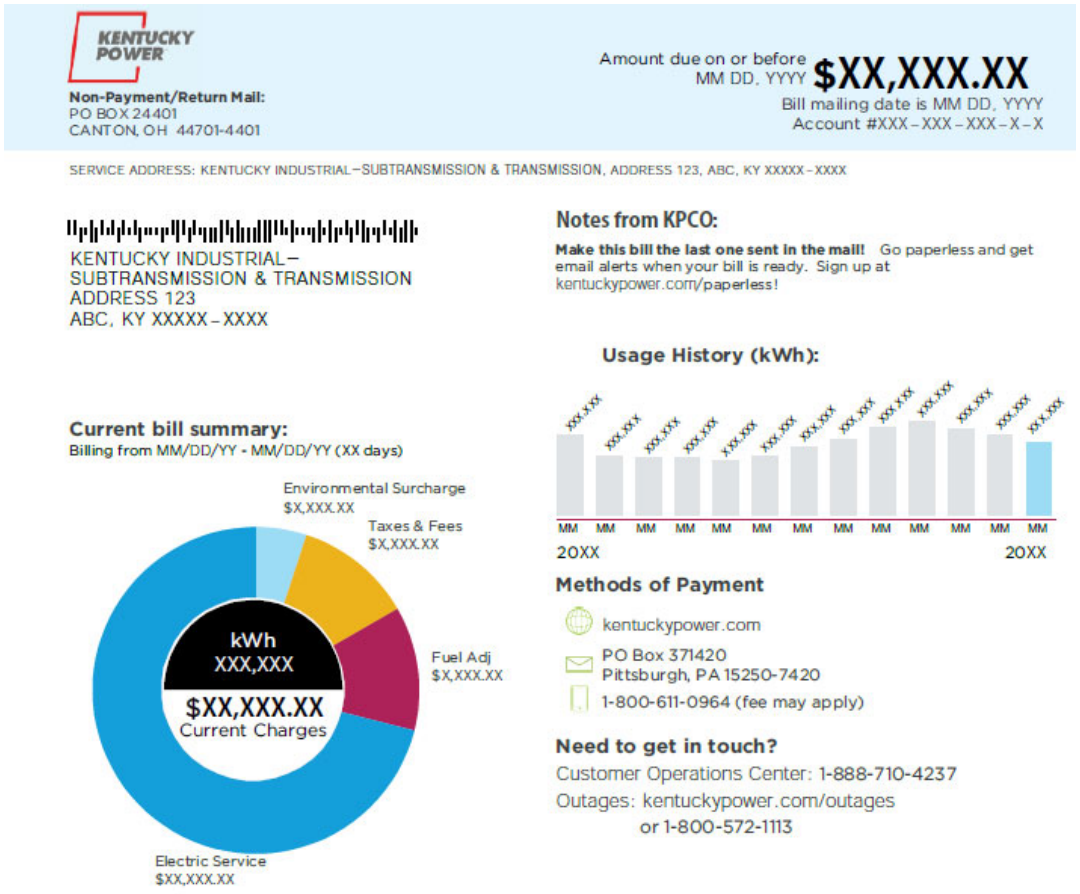
Continued on Sheet 2-25

T

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued

T



Continued on Sheet 2-26

T

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued

T

KENTUCKY POWER

Service Address:

KENTUCKY INDUSTRIAL –

SUBTRANSMISSION AND TRANSMISSION
ADDRESS 123
ABC, KY XXXXX – XXXX

Account #XXX-XXX-XXX-X-X

Billed Usage MM/YY				
Usage	Power Factor	Power Factor Constant	Meter Location Comp.	Billed Usage
XXX.XXX	-	-	-	XXX.XXX kWh
XXX.XXX	-	-	-	XXX.XXX kW On-Pk
XXX.XXX	-	-	-	XXX.XXX kW Off-Pk
Contract Capacity = X,XXX.X				High Prev Demand = X,XXX.X On-Pk High Prev Demand = X,XXX.X Off-Pk

Previous Charges		
Total Amount Due At Last Billing	$	XX,XXX.XX
Payment XX/XX/XX - Thank You		-XX,XXX.XX
Previous Balance Due	**$**	**XX.XX**

Current Charges		
Tariff XXX - Industrial General Service XX/XX/XX		
Rate Billing	$	XX,XXX.XX
Demand Charge		-X,XXX.XX
Economic Development Rider - IBDD		-X,XXX.XX
Economic Development Rider - SBDD		-X,XXX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-X,XXX.XX
Fuel Adj @ X.XXXXX Per kWh		X,XXX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
Kentucky Economic Development Surcharge @ $X.XX		X.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Purchased Power Adj. $X.XXXXX/kW		X,XXX.XX
Renewable Power Option Rider		X,XXX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Generation Rider $X.XXXXX/kW		XX.XX
City's Franchise Fee		X,XXX.XX
State Sales Tax		X,XXX.XX
Total Balance Due	**$**	**XX,XXX.XX**

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
X	X	X.XXX	Actual	X	X kVAR
X	X	X.XXX	Actual	X.XXX	XXX.XX kW On-Pk
XXXXX	Actual	XXXXX	Actual	XXX	XXX,XXX kWh
X	X	X.XXX	Actual	X.XX	XXX.X kW Off-Pk
X	X	X.XXX	Actual	X.XXX	XXX.XX kVAR
Service Period MM/DD - MM/DD					Multiplier XXX
Next scheduled read date should be between MM DD and MM DD .					

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

Notes from Kentucky Power:

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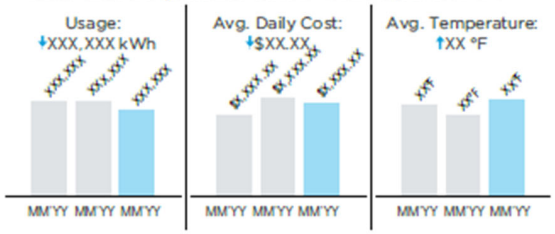
Due date does not apply to previous balance due.

Usage Details:

↑↓Values reflect changes between current month and previous month.



Total usage for the past 12 months: X,XXX,XXX kWh

Average (Avg.) monthly usage: XXX,XXX kWh

N

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In Case No.: 2025-00257 Dated XXXX XX, XXXX

Capacity and Energy Control Program

Introduction
Kentucky Power Company's Capacity and Energy Control Program outlines the procedures the Company will follow in the event of an emergency that threatens the continued reliable operation of bulk power supply system. Notwithstanding any provisions of this Capacity and Energy Control Program, the Company shall have the right to take whatever steps, with or without notice and without liability on Company's part, that Company believes necessary, in whatever order consistent with good utility practices and not on an unduly discriminatory basis, to preserve system integrity and to prevent the collapse of Company's electric system or interconnected electric network or to restore service following an outage. Such actions will be taken giving priority to maintaining service to Company's retail and full requirements customers relative to other sales whenever feasible and as allowed by law. The Company's Capacity and Energy Control Program consists of three sets of procedures:

I. Procedures During Abnormal System Frequency
II. Capacity Deficiency Program
III. Energy Emergency Control Program

Specific details regarding the Company's Capacity and Energy Control Program are included in the Company's Emergency Operating Plan ("EOP"). A copy of the Company's current EOP is on file with the Kentucky Public Service Commission in Administrative Case No. 345. Where this tariff diverts from the Company's EOP, the EOP Plan shall govern.

I. AEP/PJM Procedures During Abnormal System Frequency (EOP Section IV)

a. Purpose
Precautionary procedures are required to meet emergency conditions such as system separation and operation at subnormal frequency. In addition, the coordination of these emergency procedures with neighboring companies is essential. The AEP/PJM program described below provides procedures for reducing the consumption of electric energy on the Company's system in the event of a period of abnormal system frequency.

b. AEP/PJM Procedures
From 59.8 – 60.2 Hz, to the extent practicable, the Company will utilize all operating and emergency reserves. The manner of utilization of these reserves depends on the behavior of the System during the emergency.

For rapid frequency decline, the Company will utilize capacity that is on-line and automatically responsive to frequency (spinning reserve) and such measures as interconnection assistance and automatic load reductions to arrest the decline in frequency.

If the frequency decline is gradual, the Generation/Production Optimization Group, particularly in the deficient area, will invoke non-automatic procedures involving operating and emergency reserves. These efforts will continue until the frequency decline is arrested or until automatic load-shedding devices operate at subnormal frequencies. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities. At 59.75 Hz, the Company will suspend Automatic Generation Control (AGC) and notify Interruptible Customers to drop load.

Continued on Sheet 3-2

Capacity and Energy Control Program Continued

If at any time the decline in area frequency is arrested below 59.5 Hz, the Company will evaluate whether the area should manually shed an additional 5% of its initial load. If, after five minutes, shedding 5% of load has not returned the area frequency to 59.5 Hz or above, the area shall manually shed an additional 5% of its remaining load and continue to repeat in five-minute intervals until 59.5 Hz is reached. These steps must be completed within the time constraints imposed upon the operation of generating units that are discussed in the EOP subsection titled, "Isolation of Coal-fired Generating Units."

Automatic Load Shedding Program details are located in Section IV of the Company's EOP.

II. Capacity Deficiency Program (EOP Section III)

a. Purpose
The purpose of the Capacity Deficiency Program is to provide a plan for full utilization of emergency capacity resources and for orderly reduction in the aggregate customer demand on the American Electric Power (AEP) East/PJM Eastern System in the event of a capacity deficiency. A capacity deficiency is a shortage of generation versus load and can be caused by generating unit outages and/or extreme internal load requirements.

b. AEP East/PJM Procedures
There are three general levels of emergency actions for capacity deficiencies:

- Alerts - issued in advance of the operating day for elevated awareness and to give time for advanced preparations.
- Warnings - issued real time, typically preceding, and with an estimated time/window for a potential future action.
- Actions - issued real time and requires PJM and/or Member response. PJM actions are consistent with NERC and RFC EOP standards.

The Company may also issue an Advisory, one or more days in advance of the operating day during which a capacity deficiency may occur, that are general in nature and are for elevated awareness only. No preparations or actions are required in response to an Advisory.

Alerts

Voluntary Customer Load Curtailment Alert
The purpose of the Voluntary Customer Load Curtailment Alert is to alert members of the probable future need to implement a voluntary customer load curtailment. It is implemented whenever the estimated operating reserve capacity indicates a probable future need for voluntary customer load curtailment.

Real Time Emergency Procedures (Warnings and Actions)

Warnings
Warnings are issued in real time during present operations to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM RTO. Generally, a warning precedes an associated action. The intent of warnings is to keep all affected system personnel aware of the forecast and/or actual status of the PJM RTO.

Continued on Sheet 3-3

Capacity and Energy Control Program Continued

Actions
The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain system reliability. These measures involve:

- loading generation that is restricted for reasons other than cost
- recalling non-capacity backed off-system sales
- purchasing emergency energy from participants / surrounding pools
- load relief measures

The Company's EOP includes a nine-step warning and action procedure during capacity deficiency conditions.

c. Priority Levels
For the purpose of these capacity deficiency procedures, the following Priority Levels for loads have been established:

I. Essential Health and Safety Uses – to be given special consideration in these procedures shall, insofar as the situation permits, include the following types of use:

a. Hospitals, which shall be limited to institutions providing medical care to patients.

b. Life Support Equipment, which shall be limited to kidney machines, respirators, and similar equipment used to sustain the life of a person.

c. Police Stations and Government Detention Institutions, which shall be limited to essential uses required for police activities and the operation of facilities used for the detention of persons.

d. Fire Stations, which shall be limited to facilities housing mobile fire-fighting apparatus.

e. Communication Services, which shall be limited to essential uses required for telephone, telegraph, television, radio and newspaper operations, and operation of state and local emergency services.

f. Water and Sewage Services, which shall be limited to essential uses required for the supply of water to a community, flood pumping and sewage disposal.

g. Transportation and Defense-related Services, which shall be limited to essential uses required for the operation, guidance control and navigation of air, rail and mass transit systems, including those uses essential to the national defense and operation of state and local emergency services. These uses shall include essential services such as street, highway and signal-lighting.

Although, when practical, these types of uses will be given special consideration when implementing the manual load- shedding provisions of this program, any customer may be affected by rotating or unplanned outages and should install emergency generation equipment if continuity of service is essential. Where the emergency is system-wide in nature, consideration will be given to the use of rotating outages as operationally practicable. In case of customers supplied from two utility sources, only one source will be given special consideration. Also, any other customers who, in their opinion, have critical equipment should install emergency generation equipment.

Continued on Sheet 3-4

Capacity and Energy Control Program Continued

Priority Levels Continued

Company maintains lists of customers with life support equipment and other critical needs for the purpose of curtailments and service restorations. Company, lacking knowledge of changes that may occur at any time in Customer's equipment, operation, and backup resources, does not assume the responsibility of identifying customers with priority needs. It shall, therefore, be Customer's responsibility to notify Company if Customer has critical needs.

II. Critical Commercial and Industrial Uses – Except as described in Section C.III below, these uses shall include commercial or industrial operations requiring regimented shutdowns to prevent conditions hazardous to the general population, and to energy utilities and their support facilities critical to the production, transportation, and distribution of service to the general population. Company shall maintain a list of such customers for the purpose of curtailments and service restoration.

III. Residential Use – Residential use during certain weather conditions (for example severe winter weather) will receive precedence over critical commercial and industrial uses. The availability of Company service personnel and the circumstances associated with the outage will also be considered in the restoration of service.

IV. Non-critical commercial and industrial uses.

V. Nonessential Uses – The following and similar types of uses of electric energy shall be considered nonessential for all customers:

a. Outdoor flood and advertising lighting, except for the minimum level to protect life and property, and a single illuminated sign identifying commercial facilities when operating after dark.

b. General interior lighting levels greater than minimum functional levels.

c. Show-window and display lighting.

d. Parking lot lighting above minimum functional levels.

e. Energy use to lower the temperature below 78 degrees during operation of cooling equipment and above 65 degrees during operation of heating equipment.

f. Elevator and escalator use in excess of the minimum necessary for non-peak hours of use.

g. Energy use greater than that which is the minimum required for lighting, heating, or cooling of commercial or industrial facilities for maintenance cleaning or business-related activities during non-business hours.

Non-jurisdictional customers will be treated in a manner consistent with the curtailment procedures contained in the service agreement between the parties or the applicable tariff.

Continued on Sheet 3-5

Capacity and Energy Control Program Continued

d. Curtailment Procedures
In the event Company's load exceeds internal generation, transmission, or distribution capacity, or other system disturbances exist, and internal efforts have failed to alleviate the problem, including emergency energy purchases, the following steps may be taken, individually or in combination, in the order necessary as time permits:

1. Customers having their own internal generation capacity will be curtailed, and customers on interruptible contracts will be curtailed for the maximum hours and load allowable under their contract. Nothing in this procedure shall limit Company's rights under the Contract Service – Interruptible Power Tariff or the Alternate Feed Service Rider.

2. Power output will be maximized at Company's generating units.

3. Company use of energy at its generating stations will be reduced to a minimum.

4. Company's use of electric energy in the operation of its offices and other facilities will be reduced to a minimum.

5. The Kentucky Public Service Commission will be advised of the situation.

6. An appeal will be made to customers through the news media and/or personal contact to voluntarily curtail as much load as possible. The appeal will emphasize the defined priority levels as set forth above.

7. Customers will be advised through the use of the news media and personal contact that load interruption is imminent.

8. Implement procedures for interruption of selected distribution circuits.

e. Service Restoration Procedures
Where practical, priority uses will be considered in restoring service and service will be restored in the order I through V as defined under Priority Levels described above. However, because of the varieties of unpredictable circumstances which may exist or precipitate outages, it may be necessary to balance specific individual needs with infrastructure needs that affect a larger population. When practical, Company will attempt to provide estimates of repair times on its website to aid customers in assessing the need for alternative power sources and temporary relocations.

III. Energy Emergency Control Program (EOP Section V)

a. Introduction
The purpose of this plan is to provide for the reduction of the consumption of electric energy on the American Electric Power Company System in the event of a severe coal fuel shortage, such as might result from a general strike, or severe weather.

b. Procedures
In the event of a potential severe coal shortage, such as one resulting from a general coal strike, the following steps will be implemented. These steps will be carried out to the extent permitted by contractual commitments or by order of the regulatory authorities having jurisdiction. For further information, see EOP Section V.

With regard to mandatory curtailments, the Company proposes to monitor compliance after the fact. A customer exceeding his electric allotment would be warned to curtail his usage or face, upon continuing noncompliance and upon one day's actual written notice, disconnection of electric service for the duration of the energy emergency.

Standard Nominal Voltages

The voltage available to any individual customer shall depend upon the voltage of the Company's lines serving the area in which customer is provided service.

Electric service provided under the Company's rate schedules will be 60 hertz alternating current delivered from various load centers at nominal voltages and phases as available in a given location as follows:

Secondary Distribution Voltages

Residential Service

Single phase 120/240 volts three wire or 120/208 volts three wire on network system.

General Service - All Except Residential

Single-phase 120/240 volts three wire or 120/208 volts three wire on network system. Three-phase 120/208 volts four wire on network system, 120/240 volts four wire, 240 volts three wire, 480 volts three wire and 277/480 volts four wire, Single-phase 480 volts two wire, and Single-phase 240/480 volts three wire.

Primary Distribution Voltages

The Company's primary distribution voltage levels at load centers are 2,400; 4,160Y; 7,200; 12,470Y; 19,900 and 34,500Y.

Subtransmission Line Voltages

The Company's sub transmission voltage levels are 34,500; 46,000; and 69,000.

Transmission Line Voltages

The Company's transmission voltage levels are 138,000; 161,000; 345,000; and 765,000.

Tariff R.S.
(Residential Service)

Availability of Service
Available for full domestic electric service through 1 (one) meter to individual residential customers including rural residential customers engaged principally in agricultural pursuits.

Rate *(Tariff Codes 015, 017, 022)*

Service Charge*		
Tier 1 (0-2,000 kWh)	$26.00	per month
Tier 2 (over 2,000 kWh)	$40.00	per month
Energy Charge**		
Block 1 (0-600 kWh)	15.750¢	per kWh
Block 2 (over 600 kWh)	12.606¢	per kWh

*Customers will only be charged either the Tier 1 or Tier 2 service charge based on the customer's total energy usage for the billing period.

** Customers will be charged the Block 1 energy charge for all usage up to 600 kWh and the Block 2 energy charge for all usage above 600 kWh for the billing period.

T I I

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 33
Decommissioning Rider	Sheet No. 34
Securitized Surcharge Rider	Sheet No. 35
Federal Tax Cut Tariff	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

N T

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. Residential customers are not subject to a delayed payment charge. T

Volunteer Departments *(Tariff Code 024)*
Volunteer Fire Departments may qualify pursuant to KRS 278.172 for this tariff but will be required to provide a completed Form 990 and update it annually.

Continued on Sheet 5-2

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Tariff R.S. Continued
(Residential Service)

Storage Water Heating Provision
This provision is withdrawn except for the present installations of current customers receiving service hereunder at premises served prior to April 1, 1997.

If the customer installs a Company approved storage water heating system which consumes electrical energy only during off-peak hours as specified by the Company and stores hot water for use during on-peak hours, the following shall apply:

Tariff Code			
012	For Minimum Capacity of 80 gallons, the last 300 kWh of use in any month shall be billed at	9.317¢	per kWh
013	For Minimum Capacity of 100 gallons, the last 400 kWh of use in any month shall be billed at	9.317¢	per kWh
014	For Minimum Capacity of 120 gallons or greater, the last 500 kWh of use in any month shall be billed at	9.317¢	per kWh

These provisions, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For purpose of this provision, the on-peak billing period is defined as 7:00A.M. to 9:00P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00PM to 7:00AM for all weekdays and all hours of Saturday and Sunday.

The Company reserves the right to inspect at all reasonable times the storage water heating system and devices which qualify the residence for service under the storage water heater provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgment the availability conditions of this provision are being violated, it may discontinue billing the Customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge, and the adjustment clauses as stated in the Adjustment Clauses section.

Load Management Water-Heating Provision *(Tariff Code 011)*
For residential customers who install a load management water-heating system which consumes electrical energy during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 kWh of use in any month shall be billed at 9.317¢ per kWh.

This provision, however, shall in no event apply to the first 200 kWh used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For the purpose of this provision, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Continued on Sheet 5-3

Tariff R.S. Continued
(Residential Service)

Load Management Water Heating Provision Continued

The Company reserves the right to inspect at all reasonable times the load management water-heating system(s) and devices which qualify the residence for service under the Load Management Water-Heating Provision. If the Company finds that, in its sole judgment, the availability conditions of this provision are being violated; it may discontinue billing the Customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge, and the adjustment clauses as stated in the Adjustment Clauses section.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service.

This service is available to rural domestic customers engaged principally in agricultural pursuits where service is taken through one meter for residential purposes as well as for the usual farm uses outside the home, but it is not extended to operations of a commercial nature or operations such as processing, preparing or distributing products not raised or produced on the farm, unless such operation is incidental to the usual residential and farm uses.

The Company shall have the option of reading meters monthly or bimonthly and rendering bills accordingly. When bills are rendered bimonthly, the minimum charge and the quantity of KWH in each block of the rates shall be multiplied by two.

Pursuant to 807 KAR 5:041, Section 11, paragraph (1), of Public Service Commission Regulations, the Company will make an extension of 1,000 feet or less to its existing distribution line without charge for a prospective permanent residential customer served under this R.S.Tariff. Pursuant to 807 KAR 5:041 Section 12 extensions of up to 150 feet for a mobile home are provided without charge.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP or by special agreement. T

Continued on Sheet 5-4

Tariff R.S.-L.M.-T.O.D.
(Residential Service Load Management Time of Day)

Availability of Service
Available to customers eligible for Tariff R.S. (Residential Service) who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours.

Households eligible to be served under this tariff shall be metered through a multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods.

Rate *(Tariff Codes 028, 030, 032, 034)*

Service Charge	$ 29.00	per month	I
Energy Charge			
All kWh used during on-peak billing period	19.962¢	per kWh	
All kWh used during off-peak billing period	9.317¢	per kWh	

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Conservation and Load Management Credit
For the combination of an approved electric thermal storage space heating system and water heater, both of which are designed to consume electrical energy only between the hours of 9:00P.M. and 7:00A.M. for all days of the week, each residence will be credited 0.745¢ per kWh for all energy used during the off-peak billing period, for a total of 60 monthly billing periods following the installation and use of these devices in such residence.

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26	
Demand-Side Management Adjustment Clause	Sheet No. 28	
System Sales Clause	Sheet No. 29	
Fuel Adjustment Clause	Sheet No. 30	
Purchase Power Adjustment	Sheet No. 31	
Generation Rider	Sheet No. 32	N
Environmental Surcharge	Sheet No. 33	T
Decommissioning Rider	Sheet No. 34	
Securitized Surcharge Rider	Sheet No. 35	
Federal Tax Cut Tariff	Sheet No. 36	
City's Franchise Fee	Sheet No. 37	
School Tax	Sheet No. 38	

Continued on Sheet 5-5

Tariff R.S.-L.M.-T.O.D. Continued
(Residential Service Load Management Time of Day)

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. Residential customers are not subject to a delayed payment charge. T

Separate Metering Provision
Customers who use electric thermal storage space heating and water heaters which consume energy only during off-peak hours specified by the Company, or other automatically controlled load management devices such as space and/or water heating equipment that use energy only during off-peak hours specified by the Company, shall have the option of having these approved load management devices separately metered. The service charge for the separate meter shall be $4.45 per month. I

Separate Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service. Existing customers may initially choose to take service under this tariff without satisfying any requirements to remain on their current tariff for at least 12 months.

The Company reserves the right to inspect at all reasonable times the energy storage and load management devices which qualify the residence for service and for conservation and load management credits under this tariff, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds, that in its sole judgment, the availability conditions of this tariff are being violated; it may discontinue billing the Customer under this tariff and commence billing under the appropriate Residential Service Tariff.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP or by special agreement with the Company. T

Continued on Sheet 5-6

Tariff R.S.-T.O.D.
(Residential Service Time of Day)

Availability of Service
Available for residential electric service through a multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods to individual residential customers, including residential customers engaged principally in agricultural pursuits. Availability is limited to the first 1,000 customers applying for service under this tariff.

Rate *(Tariff Code 036)*

Service Charge	$ 29.00	per month	I
Energy Charge			
All kWh used during on-peak billing period	19.962¢	per kWh	
All kWh used during off-peak billing period	9.317¢	per kWh	

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26	
Demand-Side Management Adjustment Clause	Sheet No. 28	
System Sales Clause	Sheet No. 29	
Fuel Adjustment Clause	Sheet No. 30	
Purchase Power Adjustment	Sheet No. 31	
Generation Rider	Sheet No. 32	N
Environmental Surcharge	Sheet No. 33	T
Decommissioning Rider	Sheet No. 34	
Securitized Surcharge Rider	Sheet No. 35	
Federal Tax Cut Tariff	Sheet No. 36	
City's Franchise Fee	Sheet No. 37	
School Tax	Sheet No. 38	

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. Residential customers are not subject to a delayed payment charge. T

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

Continued on Sheet 5-7

Tariff R.S.-T.O.D.2
(Experimental Residential Service Time of Day 2)

Availability of Service
Available on a voluntary, experimental basis to individual residential customers for residential electric service through a multi-register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff.

Rate *(Tariff Code 027)*

Service Charge	$ 29.00	per month	I
Energy Charge			
All kWh used during Summer on-peak billing period	20.702¢	per kWh	
All kWh used during Winter on-peak billing period	17.881¢	per kWh	
All kWh used during off-peak billing period	12.980¢	per kWh	

For the purpose of this tariff, the on-peak and off-peak billing periods shall be defined as follows:

Months Approximate Percent (%) of Annual Hours	**On-Peak** 16%	**Off-Peak** 84%
Winter Period: November 1 to March 31	7:00 AM to 11:00 AM 6:00 PM to 10:00 PM	11:00 AM to 6:00 PM 10:00 PM to 7:00 AM
Summer Period: May 15 to September 15	Noon to 6:00 PM	6:00 PM to Noon
All Other Calendar Periods	None	Midnight to Midnight

Note: All kWh consumed during Saturday and Sunday are billed at the off-peak level.

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Continued on Sheet 5-8

Tariff R.S.-T.O.D.2 Continued
(Experimental Residential Service Time of Day 2)

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26	
Demand-Side Management Adjustment Clause	Sheet No. 28	
System Sales Clause	Sheet No. 29	
Fuel Adjustment Clause	Sheet No. 30	
Purchase Power Adjustment	Sheet No. 31	
Generation Rider	Sheet No. 32	N
Environmental Surcharge	Sheet No. 33	T
Decommissioning Rider	Sheet No. 34	|
Securitized Surcharge Rider	Sheet No. 35	|
Federal Tax Cut Tariff	Sheet No. 36	|
City's Franchise Fee	Sheet No. 37	|
School Tax	Sheet No. 38	|

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. Residential customers are not subject to a delayed payment charge. T

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP or by special agreement with the Company. T

Continued on Sheet 5-9

Tariff R.S.D.
(Residential Demand-Metered Electric Service)

Availability of Service
Available for residential electric service through one single-phase multiple-register demand meter. Availability is limited to the first 1,000 customers applying for service under this tariff.

Monthly Rate *(Tariff Code 018)*

Service Charge	$ 26.00	per customer	I
Energy Charge			
All kWh used during on-peak billing period	14.464¢	per kWh	I
All kWh used during off-peak billing period	9.317¢	per kWh	
Demand Charge	$ 8.01	for each kW of monthly billing demand	I

For the purpose of this tariff, the on-peak billing period is defined as follows:

Months of October – May:	7:00 AM to 11:00 AM for all weekdays
Months of June – September	4:00 PM to 9:00 PM for all weekdays

The off-peak billing period is defined as all weekday hours not defined above as on-peak and all hours of Saturday and Sunday

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26	
Demand-Side Management Adjustment Clause	Sheet No. 28	
System Sales Clause	Sheet No. 29	
Fuel Adjustment Clause	Sheet No. 30	
Purchase Power Adjustment	Sheet No. 31	
Generation Rider	Sheet No. 32	N
Environmental Surcharge	Sheet No. 33	T
Decommissioning Rider	Sheet No. 34	
Securitized Surcharge Rider	Sheet No. 35	
Federal Tax Cut Tariff	Sheet No. 36	
City's Franchise Fee	Sheet No. 37	
School Tax	Sheet No. 38	

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. Residential customers are not subject to a delayed payment charge. T

Monthly Billing Demand
Customer's demand will be taken monthly to be the highest registration of a 60 minute integrating demand meter or indicator during the on- peak period.

Continued on Sheet 5-10 T

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Tariff R.S.D.
(Residential Demand-Metered Electric Service)

T

Special Terms and Conditions

This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Tariff G.S.
(General Service)

Availability of Service

Available for general service customers. Customers may continue to qualify for service under this tariff until their average maximum demand exceeds 100 kW (excluding the demand served by the Load Management Time-of-Day provision).

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

Rate

Tariff Code	Service Voltage	Demand Charge ($/kW)	First 4,450 kWh (¢/kWh)	Over 4,450 kWh (¢/kWh)	Monthly Service Charge ($)	
211, 212, 215, 216, 218	Secondary	13.24	14.562	11.853	31.00	IIII
217, 220	Primary	11.85	12.887	10.543	140.00	IIII
236	Subtransmission	9.07	11.742	9.618	460.00	III-

The Demand Charge shall apply to all monthly billing demand in excess of 10 kW.

Minimum Charge

This tariff is subject to a minimum charge equal to the sum of the service charge plus the demand charge multiplied by the monthly billing demand in excess of 10 kW.

Adjustment Clauses

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27	
Demand-Side Management Adjustment Clause	Sheet No. 28	
System Sales Clause	Sheet No. 29	
Fuel Adjustment Clause	Sheet No. 30	
Purchase Power Adjustment	Sheet No. 31	
Generation Rider	Sheet No. 32	N
Environmental Surcharge	Sheet No. 33	T
Decommissioning Rider	Sheet No. 34	|
Securitized Surcharge Rider	Sheet No. 35	|
Federal Tax Cut Tariff	Sheet No. 36	|
City's Franchise Fee	Sheet No. 37	|
School Tax	Sheet No. 38	|

Delayed Payment Charge

Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. T

Metered Voltage

The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

Continued on Sheet 6-2

Tariff G.S. Continued
(General Service)

Metered Voltage Continued

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Monthly Billing Demand

Energy supplied hereunder will be delivered through not more than one single phase and/or polyphase meter. Customer's demand will be taken monthly to be the highest registration of a 15-minute integrating demand meter or indicator, or the highest registration of a thermal type demand meter. The monthly billing demand shall be the greater of: (1) Customer's metered kW demand, (2) 60% of the Customer's contract capacity in excess of 100 kW, or (3) 60% of the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 KW.

The Company reserves the right to install a demand meter on any customer receiving service under this tariff. A demand meter will be installed by the Company for customers with monthly kWh usage of 4,450 kWh or greater.

Recreational Lighting Service Provision

Available for service to customers with demands of 5 KW or greater and who own and maintain outdoor lighting facilities and associated equipment utilized at baseball diamonds, football stadiums, parks and other similar recreational areas. This service is available only during the hours between sunset and sunrise. Daytime use of energy under this rate is strictly forbidden except for the sole purpose of testing and maintaining the lighting system. All Terms and Conditions of Service applicable to Tariff G.S. customers will also apply to recreational lighting customers except for the Availability of Service.

Rate *(Tariff Code 214)*

Service Charge	$31.00	per month	I
Energy Charge	15.950¢	per kWh	I

Load Management Time of Day Provision

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements. This provision is also available for electric vehicle charging if separately metered.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

Rate *(Tariff Codes 223 and 225)*

Service Charge	$31.00	per month	I
Energy Charge			
All kWh used during on-peak billing period	22.953¢	per kWh	
All kWh used during off-peak billing period	9.493¢	per kWh	

Continued on Sheet 6-3

Tariff G.S. Continued
(General Service)

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Optional Unmetered Service Provision
Available to customers who qualify for Tariff G.S., have a demand of less than 10 KW, and use the Company's service for commercial purposes consisting of small fixed electric loads such as traffic signals and signboards which can be served by a standard service drop from the Company's existing secondary distribution system. This service will be furnished at the option of the Company.

Each separate service delivery point shall be considered a contract location and shall be separately billed under the service contract. In the event one Customer has several accounts for like service, the Company may meter one account to determine the appropriate kilowatt-hour usage applicable for each of the accounts.

The Customer shall furnish switching equipment satisfactory to the Company. The Customer shall notify the Company in advance of every change in connected load, and the Company reserves the right to inspect the customer's equipment at any time to verify the actual load. In the event of the customer's failure to notify the Company of an increase in load, the Company reserves the right to refuse to serve the contract location thereafter under this provision, and shall be entitled to bill the customer retroactively on the basis of the increased load for the full period such load was connected or the earliest date allowed by Kentucky statute whichever is applicable.

Calculated energy use per month shall be equal to the contract capacity specified at the contract location times the number of days in the billing period times the specified hours of operation. Such calculated energy shall then be billed at the following rates:

Rate *(Tariff Codes 204 (Metered) and 213 (Unmetered))*

Customer Charge	$17.00	per month	I
Energy Charge			
First 4,450 kWh per month	14.562¢	per kWh	
All Over 4,450 kWh per month	11.853¢	per kWh	

Term of Contract
Contracts under this tariff may be required of customers. Contracts under this tariff will be made for an initial period of not less than l (one) year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company will have the right to make contracts for periods of longer than 1 (one) year.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum demand in KW which the Company might be required to furnish, but no less than 10 KW. The Company shall not be obligated to supply demands in excess of that contracted for. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

Continued on Sheet 6-4

Tariff S.G.S.-T.O.D.
(Small General Service Time of Day Service)

Special Terms and Conditions Continued
This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point of both their power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP or by special agreement with the Company. T

Availability of Service
Available on a voluntary, basis for general service to customers being served at secondary distribution voltage with one single-phase, multi- register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff.

Customers not meeting the requirements for availability under this tariff will be permitted to continue service under this tariff only for continuous service at the premises occupied on or prior to June 30, 2015.

Rate *(Tariff Code 227)*

Service Charge	$31.00	per month	I
Energy Charge			
All kWh used during Summer on-peak billing period	23.244¢	per kWh	
All kWh used during Winter on-peak billing period	22.547¢	per kWh	
All kWh used during off-peak billing period	14.004¢	per kWh	

For the purpose of this tariff, the on-peak and off-peak billing periods shall be defined as follows:

Months Approximate Percent (%) of Annual Hours	**On-Peak** 16%	**Off-Peak** 84%
Winter Period: November 1 to March 31	7:00 AM to 11:00 AM 6:00 PM to 10:00 PM	11:00 AM to 6:00 PM 10:00 PM to 7:00 AM
Summer Period: May 15 to September 15	Noon to 6:00 PM	6:00 PM to Noon
All Other Calendar Periods	None	Midnight to Midnight

Note: All kWh consumed during weekends are billed at the off-peak level.

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Continued on Sheet 6-5

Tariff S.G.S.-T.O.D. Continued
(Small General Service Time of Day)

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27	
Demand-Side Management Adjustment Clause	Sheet No. 28	
System Sales Clause	Sheet No. 29	
Fuel Adjustment Clause	Sheet No. 30	
Purchase Power Adjustment	Sheet No. 31	
Generation Rider	Sheet No. 32	N
Environmental Surcharge	Sheet No. 33	T
Decommissioning Rider	Sheet No. 34	|
Securitized Surcharge Rider	Sheet No. 35	|
Federal Tax Cut Tariff	Sheet No. 36	|
City's Franchise Fee	Sheet No. 37	|
School Tax	Sheet No. 38	|

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. T

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP or by special agreement with the Company. T

Continued on Sheet 6-6

Tariff M.G.S.-T.O.D.
(Medium General Service Time of Day)

Availability of Service
Available for general service to customers with average maximum demands greater than 10 KW but not more than 100 KW being served by a multi- register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff.

Rate *(Tariff Code 229)*

Service Charge	$31.00	per month	I
Energy Charge			
All kWh used during on-peak billing period	22.953¢	per kWh	
All kWh used during off-peak billing period	9.493¢	per kWh	

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27	
Demand-Side Management Adjustment Clause	Sheet No. 28	
System Sales Clause	Sheet No. 29	
Fuel Adjustment Clause	Sheet No. 30	
Purchase Power Adjustment	Sheet No. 31	
Generation Rider	Sheet No. 32	N
Environmental Surcharge	Sheet No. 33	T
Decommissioning Rider	Sheet No. 34	
Securitized Surcharge Rider	Sheet No. 35	
Federal Tax Cut Tariff	Sheet No. 36	
City's Franchise Fee	Sheet No. 37	
School Tax	Sheet No. 38	

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. T

Continued on Sheet 6-7

Tariff M.G.S.-T.O.D. Continued
(Medium General Service Time of Day)

Metered Voltage

The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service. Existing customers may initially choose to take service under this tariff without satisfying any requirements to remain on their current tariff for at least 12 months.

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP or by special agreement with the Company. T

Tariff L.G.S.
(Large General Service)

Availability of Service

Available for general service to customers with average maximum demands greater than 100 KW but not more than 1,000 KW (excluding the demand served by the Load Management Time-of-Day provision).

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

Rate

	Service Voltage				
	Secondary	**Primary**	**Subtransmission**	**Transmission**	
Tariff Code	240, 242, 260	244, 246, 264	248, 268	250, 270	
Service Charge per Month	$111.00	$166.00	$849.00	$849.00	IIII
Demand Charge per kW	$15.76	$13.93	$9.64	$9.43	IIII
Excess Reactive Charge per KVA	$3.46	$3.46	$3.46	$3.46	
Energy Charge per kWh	10.238¢	9.339¢	7.127¢	7.008¢	IIII

Minimum Charge

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

Adjustment Clauses

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27	
Demand-Side Management Adjustment Clause	Sheet No. 28	
System Sales Clause	Sheet No. 29	
Fuel Adjustment Clause	Sheet No. 30	
Purchase Power Adjustment	Sheet No. 31	
Generation Rider	Sheet No. 32	N
Environmental Surcharge	Sheet No. 33	T
Decommissioning Rider	Sheet No. 34	|
Securitized Surcharge Rider	Sheet No. 35	|
Federal Tax Cut Tariff	Sheet No. 36	|
City's Franchise Fee	Sheet No. 37	|
School Tax	Sheet No. 38	|

Delayed Payment Charge

Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. T

Continued on Sheet 7-2

Tariff L.G.S. Continued
(Large General Service)

Metered Voltage

The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Monthly Billing Demand

Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

Determination of Excess Kilovolt-Ampere (KVA) Demand

The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

Load Management Time of Day Provision

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements. This provision is also available for electric vehicle charging if separately metered.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

Rate *(Tariff Code 251)*

Service Charge	$111.00	per month	I
Energy Charge			
All kWh used during on-peak billing period	20.310¢	per kWh	
All kWh used during off-peak billing period	9.677¢	per kWh	

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Continued on Sheet 7-3

Tariff L.G.S. Continued
(Large General Service)

Term of Contract

Contracts under this tariff will be made for customers requiring a average maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than l (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

Contract Capacity

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP or by special agreement with the Company. T

Continued on Sheet 7-4

Tariff L.G.S.-T.O.D.
(Large General Service Time of Day)

Availability of Service

Available for general service customers with average maximum demands of 100 KW or greater. Customers may continue to qualify for service under this tariff until their 12-month average demand exceeds 1,000 KW. Availability is limited to the first 500 customers applying for service under this tariff.

Rate

	Service Voltage				
	Secondary	**Primary**	**Subtransmission**	**Transmission**	
Tariff Code	256	257	258	259	
Service Charge per Month	$111.00	$166.00	$849.00	$849.00	IIII
Demand Charge per kW	$13.10	$10.78	$4.97	$4.90	IIII
Excess Reactive Charge per KVA	$3.46	$3.46	$3.46	$3.46	
On-Peak Energy Charge per kWh	14.753¢	14.084¢	13.880¢	13.709¢	IIII
Off-Peak Energy Charge per kWh	7.170¢	6.958¢	6.894¢	6.840¢	IIII

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M., for all weekdays Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Minimum Charge

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

Adjustment Clauses

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27	
Demand-Side Management Adjustment Clause	Sheet No. 28	
System Sales Clause	Sheet No. 29	
Fuel Adjustment Clause	Sheet No. 30	
Purchase Power Adjustment	Sheet No. 31	
Generation Rider	Sheet No. 32	N
Environmental Surcharge	Sheet No. 33	T
Decommissioning Rider	Sheet No. 34	|
Securitized Surcharge Rider	Sheet No. 35	|
Federal Tax Cut Tariff	Sheet No. 36	|
City's Franchise Fee	Sheet No. 37	|
School Tax	Sheet No. 38	|

Delayed Payment Charge

Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. T

Continued on Sheet 7-5

Tariff L.G.S.-T.O.D. Continued
(Large General Service Time of Day)

Metered Voltage
The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Monthly Billing Demand
Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

Determination of Excess Kilovolt-Ampere (KVA) Demand
The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

Term of Contract
Contracts under this tariff will be made for customers requiring a average maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than l (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

Contract Capacity
The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

Continued on Sheet 7-6

T

Tariff L.G.S.-T.O.D. Continued
(Large General Service Time of Day)

T

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP or by special agreement with the Company. T

Tariff I.G.S.
(Industrial General Service)

Availability of Service

Available for commercial and industrial customers with contract demands of at least 1,000 KW. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet average maximum requirements.

Rate

	Service Voltage				
	Secondary	**Primary**	**Subtransmission**	**Transmission**	
Tariff Code	356	358/370	359/371	360/372	
Service Charge per Month	$276.00	$276.00	$794.00	$1,353.00	
Demand Charge per kW					
Of monthly on-peak billing demand	$30.52	$28.33	$19.55	$19.16	IIII
Of monthly off-peak billing demand	$2.08	$2.01	$1.98	$1.96	IIII
Energy Charge per kWh	4.537¢	4.331¢	4.269¢	4.216¢	IIII

Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand…….... $0.69/KVAR

For the purpose of this tariff, the on-peak billing period is defined as 7:00 AM to 9:00 PM for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays and all hours of Saturday and Sunday.

Minimum Demand Charge

The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:

Secondary	**Primary**	**Subtransmission**	**Transmission**	
$31.91 / kW	$29.68 / kW	$20.88 / kW	$20.46 / kW	IIII

The minimum billing demand shall be the greater of 60% of the contract capacity set forth on the contract for electric service or 60% of the highest billing demand, on-peak or off-peak, recorded during the previous eleven months.

Minimum Charge

This tariff is subject to a minimum charge equal to the Service Charge plus the Minimum Demand Charge.

Adjustment Clauses

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27	
Demand-Side Management Adjustment Clause	Sheet No. 28	
System Sales Clause	Sheet No. 29	
Fuel Adjustment Clause	Sheet No. 30	
Purchase Power Adjustment	Sheet No. 31	
Generation Rider	Sheet No. 32	N
Environmental Surcharge	Sheet No. 33	T
Decommissioning Rider	Sheet No. 34	
Securitized Surcharge Rider	Sheet No. 35	
Federal Tax Cut Tariff	Sheet No. 36	
City's Franchise Fee	Sheet No. 37	
School Tax	Sheet No. 38	

Continued on Sheet 8-2

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Tariff I.G.S. Continued
(Industrial General Service)

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. T

Metered Voltage
The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KVA values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Monthly Billing Demand
The monthly on-peak and off-peak billing demands in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered by a demand meter during the on-peak and off-peak billing periods, respectively.

The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVARs as registered during the month by a demand meter or indicator.

Term of Contract
Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

Contract Capacity
The Customer shall set forth the amount of capacity contracted for ("the contract capacity") in an amount equal to or greater than 1,000 KW in multiples of 100 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for resale service to mining and industrial Customers who furnish service to Customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point for both the power and camp requirements.

Continued on Sheet 8-3

Tariff I.G.S. Continued
(Industrial General Service)

Special Terms and Conditions Continued

This tariff is also available to Customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum amount of demand in KW which the Company might be required to furnish, but not less than 1,000 KW. The Company shall not be obligated to supply demands in excess of that contracted capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP or by special agreement with the Company. T

Applicable on and after March 18, 2025, to existing commercial and industrial customers that add 150 MW or more of incremental load and new commercial and industrial customers that have at least 150 MW. The following terms and conditions apply:

Contracts will be made for an initial period of twenty (20) years and shall remain in effect thereafter unless cancelled or modified pursuant to the terms hereunder.

Either party shall give at least five years' written notice to the other of the intention to discontinue service under the terms of this Schedule. Such notice shall not reduce the twenty-year initial term. In the event of a permanent closure by the customer occurring after the first five (5) years of the initial contract term, the customer may exit the contract by providing a one-time payment equal to five (5) years of minimum billing under this Schedule.

The customer shall give at least five (5) years' written notice to the Company of the intention to reduce the contract capacity specified in the contract, but any contract capacity changes may be implemented with less than five (5) years notice with mutual agreement. Such notice shall not reduce the maximum contract capacity established during the term of the contract by more than 20%, except by mutual agreement. Such notice shall not be given and will not be accepted during the first five (5) years of the initial contract term.

In addition to the Monthly Billing Demand provisions, the customer's monthly billing demand shall in no event be less than 90% of the greater of (a) the customer's on-peak contract capacity or b) the customer's highest previously established monthly billing demand during the past 11 months or (c) the customer's maximum demand created during the billing month.

The customer shall provide collateral in a form acceptable to the Company based upon the creditworthiness of the customer. The amount of collateral provided shall be equal to 24 times the customer's previous maximum monthly non-fuel bill. During the first year of the contract, the maximum expected bill for the year shall be used. The amount of collateral to be provided will be recomputed annually, and updated if the recomputed value is 10% greater than the current amount held.

Tariff M.W.
(Municipal Waterworks)

Availability of Service
Available only to incorporated cities and towns and authorized water districts and to utility companies operating under the jurisdiction of Public Service Commission of Kentucky for the supply of electric energy to waterworks systems and sewage disposal systems served under this tariff on September 1, 1982, and only for continuous service at the premises occupied by the Customer on this date. If service hereunder is discontinued, it shall not again be available.

Customer shall contract with the Company for a reservation in capacity in kilovolt-amperes sufficient to meet with the maximum load, which the Company may be required to furnish.

Rate *(Tariff Code 540)*

Service Charge	$28.00	per month	I
Energy Charge All kWh used per month	13.979¢	per kWh	I

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the sum of the service charge plus $10.22 per KVA as determined from customer's total connected load. I

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27	
Demand-Side Management Adjustment Clause	Sheet No. 28	
System Sales Clause	Sheet No. 29	
Fuel Adjustment Clause	Sheet No. 30	
Purchase Power Adjustment	Sheet No. 31	
Generation Rider	Sheet No. 32	N
Environmental Surcharge	Sheet No. 33	T
Decommissioning Rider	Sheet No. 34	
Securitized Surcharge Rider	Sheet No. 35	
Federal Tax Cut Tariff	Sheet No. 36	
City's Franchise Fee	Sheet No. 37	
School Tax	Sheet No. 38	

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. T

Term of Contract
Contracts under this tariff will be made for not less than (1) one year with self-renewal provisions for successive periods of (1) one year each until either party shall give at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period. The Company will have the right to require contracts for periods of longer than (1) one year.

Continued on Sheet 9-2 T

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Tariff M.W. Continued
(Municipal Waterworks)

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Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is not available to customers having other sources of energy supply.

Tariff O.L.
(Outdoor Lighting)

Availability of Service
Available for outdoor lighting to individual customers in locations where municipal street lighting is not applicable provided the lighting location designated by the Customer is reasonably accessible to the Company's service vehicles without causing damage to the Customer's or other's property. New installations of High Pressure Sodium, Mercury Vapor and Metal Halide lamps shall cease on January 14, 2021.

Base Fuel Rate
Customers receiving service under this tariff will receive bills calculated using per lamp and base fuel charge. The base fuel charge will be calculated each month as shown below by multiplying the approved base fuel amount set forth in the Company's Fuel Adjustment Clause tariff by the relevant monthly kWh value set forth in the monthly kWh table included below in the Adjustment Clauses section of this tariff.

Rate

A. Overhead Lighting Service

	Tariff Code	Watts	Rate	
High Pressure Sodium	094	100 (9,500 Lumens)	$11.84	per lamp + 0.03380 x kWh in Sheet No. 10-4
	113	150 (16,000 Lumens)	$13.50	per lamp + 0.03380 x kWh in Sheet No. 10-4
	097	200 (22,000 Lumens)	$16.36	per lamp + 0.03380 x kWh in Sheet No. 10-4
	103	250 (28,000 Lumens)	$23.32	per lamp + 0.03380 x kWh in Sheet No. 10-4
	098	400 (50,000 Lumens)	$25.84	per lamp + 0.03380 x kWh in Sheet No. 10-4

	Tariff Code	Watts	Rate	
Mercury Vapor	093	175 (7,000 Lumens)	$15.09	per lamp + 0.03380 x kWh in Sheet No. 10-4
	095	400 (20,000 Lumens)	$25.97	per lamp + 0.03380 x kWh in Sheet No. 10-4

	Tariff Code	Lumens	Rate	
LED	150	6,000-10,000	$8.65	per lamp + 0.03380 x kWh in Sheet No. 10-4

Company will provide lamp, photo-electric relay control equipment, luminaries and upsweep arm not over six feet in length, and will mount same on an existing pole carrying secondary circuits.

B. Post-Top Lighting Service

	Tariff Code	Watts	Rate	
High Pressure Sodium	111	100 (9,500 Lumens)	$21.46	per lamp + 0.03380 x kWh in Sheet No. 10-4
	122	150 (16,000 Lumens)	$33.75	per lamp + 0.03380 x kWh in Sheet No. 10-4
	120	250 (19,000 Lumens)	$39.29	per lamp + 0.03380 x kWh in Sheet No. 10-4
	126	400 (40,000 Lumens)	$51.57	per lamp + 0.03380 x kWh in Sheet No. 10-4

	Tariff Code	Watts	Rate	
Mercury Vapor	099	175 (7,000 Lumens)	$17.31	per lamp + 0.03380 x kWh in Sheet No. 10-4

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Continued on Sheet 10-2

Tariff O.L. Continued
(Outdoor Lighting)

Post-Top Lighting Service Continued

	Tariff Code	Lumens	Rate		
LED	160	6,000-10,000	$24.90	per lamp + 0.03380 x kWh in Sheet No. 10-4	I

Company will provide lamp photo-electric relay control equipment, luminaries, post, and installation including underground wiring for a distance of thirty feet from the Company's existing secondary circuits. Incremental costs of installation beyond thirty feet shall be the responsibility of the customer.

C. Flood Lighting Service

	Tariff Code	Watts	Rate		
High Pressure Sodium	107	200 (22,000 Lumens)	$18.79	per lamp + 0.03380 x kWh in Sheet No. 10-4	I
	109	400 (50,000 Lumens)	$27.44	per lamp + 0.03380 x kWh in Sheet No. 10-4	

	Tariff Code	Watts	Rate	
Metal Halide	110	250 (20,500 Lumens)	$22.80	per lamp + 0.03380 x kWh in Sheet No. 10-4
	116	400 (36,000 Lumens)	$28.72	per lamp + 0.03380 x kWh in Sheet No. 10-4
	131	1,000 (110,000 Lumens)	$52.28	per lamp + 0.03380 x kWh in Sheet No. 10-4
	130	250 Mongoose (20,500 Lumens)	$29.74	per lamp + 0.03380 x kWh in Sheet No. 10-4
	136	400 Mongoose (36,000 Lumens)	$36.30	per lamp + 0.03380 x kWh in Sheet No. 10-4

	Tariff Code	Lumens	Rate	
LED	165	17,500-22,500	$32.33	per lamp + 0.03380 x kWh in Sheet No. 10-4
	166	42,500-47,500	$39.73	per lamp + 0.03380 x kWh in Sheet No. 10-4

Company will provide lamp, photoelectric relay control equipment, luminaries, mounting bracket, and mount same on an existing pole carrying secondary circuits.

D. LED Lamp Conversion Charge
Existing outdoor lighting customers that wish to convert from non-LED lamps to new LED fixtures shall pay a monthly charge of $3.33 per lamp replaced, per month for 84 months.

All lumen figures are based upon manufacturer estimates and may vary.

When new or additional facilities, other than those specified in Paragraphs A, B, and C, are to be installed by the Company, the customer in addition to the monthly charges, shall pay in advance the installation cost (labor and material) of such additional facilities extending from the nearest or most suitable pole of the Company to the point designated by the customer for the installation of said lamp, except that customer may, for the following facilities only, elect, in lieu of such payment of the installation cost to pay:

Continued on Sheet 10-3

Tariff O.L. Continued
(Outdoor Lighting)

Post-Top Lighting Service Continued

Wood Pole	$4.70	per month	I
Overhead wire span not over 150 feet	$2.25	per month	R
Underground wire lateral not over 50 feet	$7.65	per month	R

(Price includes pole riser and connections)

E. Flexible Lighting Option *(Tariff Code 175 for Unmetered and Tariff Code 201 for Metered)*
Applicable for the installation of any outdoor area lighting system (System) on a private or public property and owned by the Company. The customer must be adjacent to an electric power line of the Company that is adequate for supplying the necessary electric service. Service for the System under this tariff shall require a contract addendum agreed to and signed by the customer. The System shall comply with the Company's terms and conditions unless otherwise noted in this section. Included in the contract addendum shall be the installed capital cost of the System and the monthly amount of kWh the System will use if it is not metered. The Company reserves the right to refuse service under this provision based on customer's creditworthiness.

Rate
Customers shall pay the monthly lamp charge for the System, a monthly maintenance charge, a non-fuel energy charge, a base fuel charge, and all applicable adjustment clauses.

Monthly Lamp Charge* = IC x MLFCR

Where:
IC = Installed Cost of System
MLFCR = Monthly Levelized Fixed Cost Rate of 1.48% which is inclusive of return, depreciation, income taxes, property taxes and A&G expense components I

Monthly maintenance charge is $2.53 per lamp per month I
Monthly non-fuel charge is 0.08523 $/kWh R
Base fuel charge is 0.03380 $/kWh

Customers selecting this flexible lighting option to replace existing lamps shall also be subject to the LED Lamp Conversion Charge.

*Customers may pay a portion of the installed cost upfront to reduce the monthly lamp charge component of the rate.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

System Sales Clause	Sheet No. 29	
Fuel Adjustment Clause	Sheet No. 30	
Purchase Power Adjustment	Sheet No. 31	
Generation Rider	Sheet No. 32	N
Environmental Surcharge	Sheet No. 33	T
Decommissioning Rider	Sheet No. 34	
Securitized Surcharge Rider	Sheet No. 35	
Federal Tax Cut Tariff	Sheet No. 36	
City's Franchise Fee	Sheet No. 37	
School Tax	Sheet No. 38	

Continued on Sheet 10-4

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Tariff O.L. Continued
(Outdoor Lighting)

For adjustments calculated on a per kWh basis the following kWh values will be used in the calculation:

	Metal Halide			Mercury Vapor		High Pressure Sodium				
	250 Watts	400 Watts	1,000 Watts	175 Watts	400 Watts	100 Watts	150 Watts	200 Watts	250 Watts	400 Watts
Jan	127	199	477	91	199	51	74	106	130	210
Feb	106	167	400	76	167	43	62	89	109	176
Mar	106	167	400	76	167	43	62	89	109	176
Apr	90	142	340	65	142	36	53	76	93	150
May	81	127	304	58	127	32	47	68	83	134
Jun	72	114	272	52	114	29	42	61	74	120
Jul	77	121	291	55	121	31	45	65	79	128
Aug	88	138	331	63	138	35	51	74	90	146
Sep	96	152	363	69	152	39	57	81	99	160
Oct	113	178	427	81	178	45	66	95	116	188
Nov	119	188	449	86	188	48	70	100	122	198
Dec	129	203	486	92	203	52	75	108	132	214
Total	1,204	1,896	4,540	864	1,896	484	704	1,012	1,236	2,000

	Light Emitting Diode (LED)			
	150 Tariff Code 6,000-10,000 Lumens	160 Tariff Code 6,000-10,000 Lumens	165 Tariff Code 17,500-22,500 Lumens	166 Tariff Code 42,500-47,500 Lumens
Jan	28	33	75	154
Feb	24	28	63	129
Mar	24	28	63	129
Apr	20	24	53	109
May	18	21	48	96
Jun	16	19	43	87
Jul	17	20	46	93
Aug	19	23	52	105
Sep	22	26	58	118
Oct	25	30	67	136
Nov	27	32	71	145
Dec	29	33	77	156
Total	269	317	716	1,457

Continued on Sheet 10-5

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Woffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Tariff O.L. Continued
(Outdoor Lighting)

Delayed Payment Charge
Residential customers are not subject to a delayed payment charge. Other delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. T

Hours of Lighting
All lamps shall burn from one-half hour after sunset until one-half hour before sunrise every night and all night, burning approximately 4,000 hours per annum.

Ownership of Facilities
All facilities necessary for service including fixtures, controls, poles, transformers, secondaries, lamps and other appurtenances shall be owned and maintained by the Company. All service and necessary maintenance will be performed only during the regular scheduled working hours of the Company.

The Company shall be allowed 3 working days after notification by the customer to replace all burned-out lamps.

Term of Initial Service
Term of initial service shall be required for a period of one year. If early termination is requested or service is terminated during the initial 12 month period, the customer will be billed for the remainder of the 12 month period on the final bill.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

The Company shall have the option of rendering monthly or bimonthly bills.

Customer's account balance must be current prior to installation of new or additional lights.

Tariff S.L.
(Street Lighting)

Availability of Service
Available for lighting service for all the lighting of public streets, public highways and other public outdoor areas in municipalities, counties, and other governmental subdivisions where such service can be supplied from the existing general distribution systems provided the lighting location designated by the Customer is reasonably accessible to the Company's service vehicles without causing damage to the Customer's or other's property. New installations of High Pressure Sodium lamps shall cease on January 14, 2021.

Base Fuel Rate
Customers receiving service under this tariff will receive bills calculated using per lamp and base fuel charge. The base fuel charge will be calculated each month as shown below by multiplying the approved base fuel amount set forth in the Company's Fuel Adjustment Clause tariff by the relevant monthly kWh value set forth in the monthly kWh table included below in the Adjustment Clauses section of this tariff.

Rate *(Tariff Code 528)*
A. Overhead Service on Existing Distribution Poles

	Watts	Rate	
High Pressure Sodium	100 (9,500 Lumens)	$10.02	per lamp + 0.03380 x kWh in Sheet No. 11-3
	150 (16,000 Lumens)	$11.00	per lamp + 0.03380 x kWh in Sheet No. 11-3
	200 (22,000 Lumens)	$13.03	per lamp + 0.03380 x kWh in Sheet No. 11-3
	400 (50,000 Lumens)	$17.11	per lamp + 0.03380 x kWh in Sheet No. 11-3

	Lumens	Rate	
LED	8,000-11,000	$11.47	per lamp + 0.03380 x kWh in Sheet No. 11-3
	10,000-14,000	$14.72	per lamp + 0.03380 x kWh in Sheet No. 11-3
	24,000-30,000	$17.55	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 6,000-10,000	$11.91	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 8,000-12,000	$26.41	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Flood 17,500-22,500	$19.33	per lamp + 0.03380 x kWh in Sheet No. 11-3

B. Service on New Wood Distribution Poles

	Watts	Rate	
High Pressure Sodium	100 (9,500 Lumens)	$15.66	per lamp + 0.03380 x kWh in Sheet No. 11-3
	150 (16,000 Lumens)	$16.78	per lamp + 0.03380 x kWh in Sheet No. 11-3
	200 (22,000 Lumens)	$18.82	per lamp + 0.03380 x kWh in Sheet No. 11-3
	400 (50,000 Lumens)	$24.15	per lamp + 0.03380 x kWh in Sheet No. 11-3

	Lumens	Rate	
LED	8,000-11,000	$18.90	per lamp + 0.03380 x kWh in Sheet No. 11-3
	10,000-14,000	$22.17	per lamp + 0.03380 x kWh in Sheet No. 11-3
	24,000-30,000	$25.01	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 6,000-10,000	$19.34	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 8,000-12,000	$33.85	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Flood 17,500-22,500	$26.78	per lamp + 0.03380 x kWh in Sheet No. 11-3

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Continued on Sheet 11-2

Tariff S.L. Continued
(Street Lighting)

C. Service on New Metal or Concrete Poles*

	Watts	Rate	
High Pressure Sodium	100 (9,500 Lumens)	$32.63	per lamp + 0.03380 x kWh in Sheet No. 11-3
	150 (16,000 Lumens)	$33.82	per lamp + 0.03380 x kWh in Sheet No. 11-3
	200 (22,000 Lumens)	$35.86	per lamp + 0.03380 x kWh in Sheet No. 11-3
	400 (50,000 Lumens)	$39.94	per lamp + 0.03380 x kWh in Sheet No. 11-3

	Lumens	Rate	
LED	8,000-11,000	$33.03	per lamp + 0.03380 x kWh in Sheet No. 11-3
	10,000-14,000	$35.24	per lamp + 0.03380 x kWh in Sheet No. 11-3
	24,000-30,000	$36.98	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 6,000-10,000	$34.01	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 8,000-12,000	$48.34	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Flood 17,500-22,500	$38.71	per lamp + 0.03380 x kWh in Sheet No. 11-3

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* Effective June 29, 2010 and thereafter these lamps are not available for new installations

D. LED Lamp Conversion Charge

Existing street lighting customers that wish to convert from non-LED lamps to a new LED fixture shall pay a monthly charge of $2.18 per lamp replaced, per month for 84 months.

All lumen figures are based upon manufacturer estimates and may vary.

E. Flexible Lighting Option *(Tariff Code 525 for Unmetered and Tariff Code 526 for Metered)*

Applicable for the installation of any street lighting system (System) on a private or public property and owned by the Company. The customer must be adjacent to an electric power line of the Company that is adequate for supplying the necessary electric service. Service for the System under this tariff shall require a contract addendum agreed to and signed by the customer. The System shall comply with the Company's terms and conditions unless otherwise noted in this section. Included in the contract addendum shall be the installed capital cost of the System and the monthly amount of kWh the System will use unless the system is separately metered. The Company reserves the right to refuse service under this provision based on customer's credit worthiness.

Rate

Customers shall pay the monthly lamp charge for the System, a monthly maintenance charge, a non-fuel energy charge, a base fuel charge, and all applicable adjustment clauses.

Monthly Lamp Charge* = IC x MLFCR

Where:
IC = Installed Cost of System
MLFCR = Monthly Levelized Fixed Cost Rate of 1.09% which is inclusive of return, depreciation, income taxes, property taxes and A&G expense components

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Continued on Sheet 11-3

Tariff S.L. Continued
(Street Lighting)

Monthly maintenance charge is $2.50 per lamp per month
Monthly non-fuel charge is 0.06102 $/kWh
Base fuel charge is 0.03380 $/kWh

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Customers selecting this flexible lighting option to replace existing lamps shall also be subject to the LED Lamp Conversion Charge.

*Customers may pay a portion of the installed cost upfront to reduce the monthly lamp charge component of the rate.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 33
Decommissioning Rider	Sheet No. 34
Securitized Surcharge Rider	Sheet No. 35
Federal Tax Cut Tariff	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

N
T

For adjustments calculated on a per kWh basis the following kWh values will be used in the calculation:

	High Pressure Sodium				Light Emitting Diode (LED)					
	100 Watts	150 Watts	200 Watts	400 Watts	8,000-11,000 Lumens	10,000-14,000 Lumens	24,000-30,000 Lumens	Post Top 6,000-10,000 Lumens	Post Top 8,000-12,000 Lumens	Flood 17,500-22,500 Lumens
Jan	51	74	106	210	35	49	98	33	48	75
Feb	43	62	89	176	30	40	83	28	41	63
Mar	43	62	89	176	30	40	83	28	41	63
Apr	36	53	76	150	25	34	70	24	34	53
May	32	47	68	134	22	30	62	21	31	48
Jun	29	42	61	120	20	27	56	19	27	43
Jul	31	45	65	128	21	29	60	20	29	46
Aug	35	51	74	146	23	33	68	23	32	52
Sep	39	57	81	160	27	37	75	26	37	58
Oct	45	66	95	188	31	43	87	30	43	67
Nov	48	70	100	198	33	46	93	32	45	71
Dec	52	75	108	214	36	50	100	33	50	77
Total	484	704	1,012	2,000	333	458	935	317	458	716

Continued on Sheet 11-4

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Tariff S.L. Continued
(Street Lighting)

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. T

Special Facilities
When a customer requests street lighting service which requires special poles or fixtures, underground street lighting, or a line extension of more than one span of approximately 150 feet, the customer will be required to pay, in advance, an aid-to-construction in the amount of the installed cost of such special facilities.

Hours of Lighting
All lamps shall burn from one-half hour after sunset until one-half hour before sunrise every night and all night, burning approximately 4,000 hours per annum.

Term of Contract
Contracts under this tariff will ordinarily be made for an initial term of one year with self-renewal provisions for successive periods of one year each until either party shall give at least 60 days' notice to the other of the intention to discontinue at the end of the initial term or any yearly period. The Company may have the right to require contracts for periods of longer than one year if new or additional facilities are required.

Special Terms and Conditions
A customer's account balances must be current prior to installation of new or additional lights.

Tariff P.A.
(Pole Attachments)

1. Availability of Service

Available to broadband internet providers, cable television system operators, governmental units and telecommunications carriers that provide service within the operating area of Kentucky Power Company (Company). This Tariff is not available to: (1) the Attachments of utilities, including local exchange carriers (LECs), that have joint use agreements with Company; or (2) macro cell facilities. Nothing in this Tariff expands the right to attach to Company's facilities beyond the rights otherwise conveyed by law.

2. Definitions

Unless stated otherwise, the terms used in this Tariff shall have the same meaning as the terms expressly defined in Section 1 of 807 KAR 5:015.

"Approved Contractor" means a contractor approved by Company for a particular purpose.

"Attachment" means a Wireline Facility or Wireless Facility and all associated equipment, including without limitation, any overlashed cable or fiber, guying, small splice panels and vertical overhead to underground risers but shall not include power supplies, equipment cabinets, meter bases or other equipment that impedes accessibility or otherwise conflicts with Company's standards. For billing purposes, the term "Attachment" also includes: (1) a Service Drop affixed to a pole that is located more than one (1) vertical foot away from the point at which the messenger strand is attached to the pole; and (2) a Service Drop located on a dedicated service, drop or lift pole.

"Communications Space" means the area on a pole below the Communications Worker Safety Zone and above the point on the pole necessary to meet NESC clearance, department of transportation or other governmental requirements, and Company's construction standards.

"Facility" means any Company Distribution Pole, right-of-way, conduit or duct normally used by Company to support or protect its electric conductors. The term "Facility" does not include any Transmission Pole.

"Distribution Pole" means a utility pole supporting electric supply facilities, all of which operate at less than 69kV, but does not include a pole used primarily to support outdoor lighting.

"NESC" means the National Electrical Safety Code.

"Larger Order" means an application, or multiple applications submitted within thirty (30) days of one another, seeking to make Attachments to more than three hundred (300) poles except that for the period during which 807 KAR 5:015E is in effect, such term shall mean an application or applications submitted within thirty (30) days of one another seeking to make Attachments to more than 500 poles.

"Operator" means a broadband internet provider, cable television system operator, governmental unit or telecommunications carrier.

"Overlashing" means the practice whereby an entity, whether Operator or a third party, physically connects or attaches, through lashing or otherwise, new fiber optic or coaxial cable, or any other type of cable, to an existing Wireline Attachment on a Distribution Pole.

"Service Drop" means a Wireline Facility, attached to a pole with a J-hook or other similar hardware, that connects the trunk line to an end user's premises, and extends directly from the trunk line to a drop/lift pole or into an end user's premises.

Continued on Sheet 12-2

Tariff P.A. Continued
(Pole Attachments)

"Transmission Pole" means any utility pole or tower supporting electric supply facilities designed to operate at 69kV or greater.

"Wireline Facility" means fiber optic or coaxial cable, or any other type of cable, as well as any messenger wire or support strand.

"Wireless Facility" means, without limitation, antennas, risers, transmitters, receivers, and all other associated equipment used in connection with Operator's provision of wireless communications services and the transmission and reception of radiofrequency signals, but shall not include power supplies, equipment cabinets, meter bases, and other equipment that impedes accessibility or that conflicts with Company's standards. The term "Wireless Facility" does not include any strand-mounted antennas or macro cell facilities.

3. Rate

Charge for Wireline Facility on a two-user pole	$10.82	per attachment per year
Charge for Wireline Facility on a three-user pole	$6.71	per attachment per year

The above rate was calculated in accordance with the following formula:

Weighted Average Bare Pole Cost	x	Usage Factor	x	Carrying Charge	=	Rate Per Pole

A two-user pole is a pole being used, by actual occupation or reservation, by the Operator and the Company. A three-user pole is a pole being used by actual occupation or reservation, by the Operator, the Company, and a third party.

Charge for Attachments within ducts or conduits	$2.70	per linear foot per year
Charge for attachment of Wireless Facility to top of Distribution Pole	$150	per attachment per year
Charge for attachment of Wireless Facility within Communications Space of Distribution Pole	$75	per attachment per year

The above rates are subject to revision from time to time as approved by the Commission.

4. Company Facilities Subject to Attachment

Pursuant to 807 KAR 5:015 and the terms and conditions of this Tariff, Attachments to Company Facilities that do not interfere with Company's electric service requirements shall be permitted. Company may deny access to any Company Facility on a non-discriminatory basis where there is insufficient capacity or for reasons of safety, reliability, and generally applicable engineering purposes.

All Company Facilities covered by this Tariff remain the property of Company regardless of any payment by Operator toward their cost. No use, however extended, of Company Facilities or payment of any fee or charge required hereunder shall create or vest in Operator any claim or right, possession, title, interest or ownership in such Facilities. Nothing in this Tariff shall be construed to obligate Company to construct, reconstruct, retain, extend, repair, place, replace or maintain any Facility which, in Company's sole discretion, is not needed for Company's own purposes. Company and its successors and assigns shall have the right to operate, relocate and maintain Company Facilities in such a manner as will best enable Company, in its sole discretion, to fulfill its service requirements.

Continued on Sheet 12-3

Tariff P.A. Continued
(Pole Attachments)

5. Company's Pole Attachment Policy Handbook; Website

Operator is expected to follow the processes and guidelines set forth in Company's Pole Attachment Policy handbook, as well as any amendments thereto, but only to the extent that such processes and guidelines do not conflict with 807 KAR 5:015 (and 807 KAR 5:015E during the period such emergency regulation is effective) or this Tariff.

D

The Pole Attachment Policy handbook can be found at https://www.kentuckypower.com/business/b2b/pole-attachment. This website, which is maintained by Company, also includes: (a) the identity and contact information for contractors approved by Company to conduct surveys and self-help above the communications space; (b) Company's construction standards applicable to Attachments; (c) contact information for Company personnel responsible for invoicing, payment, make-ready work, and escalation of disputes; and (d) other relevant information.

Company reserves the right to update or revise the information posted on the above-referenced website from time to time. Attachment Customer shall ensure that it is utilizing up-to-date information before taking any action upon such information.

6. Applications

When Operator proposes to furnish service within Company's operating area and desires to make Attachments to Company Facilities, Operator shall make written application to install such Attachments, in the format required by Company, that specifies the location of each Facility in question, the character of its proposed Attachments, and any other information necessary to calculate the transverse and vertical load placed upon the pole as a result of the proposed Attachment and any other attachments or equipment attached to the Facility. If Operator's application qualifies as a Larger Order, Operator shall provide Company at least ninety (90) days' advance written notice before submission to Company. Company will notify Operator, within the time required by law, if the application is incomplete. If the application is incomplete, Operator shall provide the additional information required by Company prior to Company's review of the application on its merits.

If Operator is only seeking to make Wireline Attachments to Distribution Poles, Company shall complete a make-ready survey within the time required by law of receipt of a complete application. Company may, in its sole discretion, require prepayment for a make-ready survey. The current per pole estimate for a make-ready survey is $275. If the actual cost of performing the make-ready survey exceeds the amount of Operator's prepayment, then Operator shall reimburse Company for any difference upon receipt of an invoice for such amount. If the actual cost of performing the make-ready survey is less than the amount of Operator's prepayment, then Company shall issue Operator a refund for the difference. Company shall use commercially reasonable efforts to provide at least five (5) days advance notice of a field inspection to Operator and any other affected third party.

Within the time required by law after receipt of a complete application, Company shall notify Operator whether and to what extent any special conditions will be required to permit the use by Operator of each such pole. Within fourteen (14) days of providing such notice, Company shall provide Operator with a statement of the costs for any necessary Company make-ready work, including the cost of rearranging Company's electric supply facilities or pole changeouts. Operator shall indicate its approval of the make-ready cost statement by submitting payment to Company within fourteen (14) days of receipt of the make-ready cost statement. If payment is not received by Company within fourteen (14) days, then Company's make-ready cost statement shall be deemed withdrawn. Within seven (7) days of receipt of Operator's payment, Company shall notify, in a manner consistent with applicable law, all third parties whose attachments might be affected by the make-ready, and thereafter provide Operator with the contact information for, and copies of the notices sent to, such third parties. Thereafter, Operator shall be responsible for coordinating the rearrangement or transfer of any third-party attachment and shall pay the costs related thereto.

Continued on Sheet 12-4

Tariff P.A. Continued
(Pole Attachments)

Operator shall reimburse Company for any expenses incurred in reviewing Operator's written applications for attachment. Operator shall have a non-exclusive right to use such Facilities of Company as may be used or reserved for use by Operator and any other Facilities of Company when brought hereunder in accordance with the procedure hereinafter provided. Company shall have the right to grant to others, by contract or otherwise, rights or privileges to use any Facilities of Company and Company shall have the right to continue and extend any such rights or privileges heretofore granted.

D

7. Standards for Installation

All Attachments and associated equipment of Operator shall be installed in a manner satisfactory to Company and so as not to interfere with the present or any future use which Company may desire to make of the Facilities covered by this Tariff. All such Attachments and equipment shall be installed and at all times maintained by Operator so as to comply with the standards set forth in Company's Pole Attachment Policy handbook, the NESC and any other applicable regulations or codes promulgated by state, local or other governmental authority having jurisdiction thereover. In the event of a conflict, the more stringent standard shall apply. Operator shall take necessary precautions by the installation of protective equipment or other means, to protect all persons and property of all kinds against injury or damage occurring by reason of Operator's attachments.

Operator shall complete the installation of its Attachments within thirty (30) days of Company's approval of the application for such Attachments, or if make-ready is required to accommodate the Attachments, the completion date of such make-ready. Operator shall, within seven (7) days after completing the installation of its Attachments, provide Company with written notice of such completion (except that such notice may be provided within fifteen (15) days after completing the installation of Attachments during the period 807 KAR 5:015E is effective), and Company shall have the right to perform a post-inspection on such Attachments, at Operator's sole expense, within ninety (90) days of receipt of Operator's notice of completion. If Company's inspection reveals that Operator's installation resulted in any property damage or code violations, Company may either: (1) complete any necessary remedial work and bill Operator for the costs related to fixing the damage or correcting the code violations; or (2) require Operator to fix the damage or code violations at its own expense within fourteen (14) days' notice from Company.

8. Tagging Requirement

Operator shall identify each of its Attachments with a tag, approved in advance by Company, that includes Operator's name, 24-hour contact telephone number, and such other information as Company may require. Operator shall tag an Attachment at the time of construction. Any untagged Attachment existing as of the effective date of this Tariff shall be tagged by Operator by no later than June 30, 2025.

9. Overlashing

Operator shall provide Company with at least thirty (30) days' advance written notice before Overlashing, or allowing a third party to overlash, Operator's existing Wireline Facilities. Operator is responsible for all Overlashing performed on its Wireline Facilities, including any Overlashing by a third party, and shall ensure that all Overlashing complies with Company's standards, the applicable provisions of the NESC, and any other applicable law or code. If Overlashing of Operator's Wireline Facilities results in any damage to the pole, Company equipment or existing Attachments, or if any Overlashing causes a safety or engineering standard violation, Operator shall be responsible, at its expense, for any necessary repairs or corrections.

Continued on Sheet 12-5

Tariff P.A. Continued
(Pole Attachments)

T

Overlashing Continued

Operator shall notify Company within fifteen (15) days of completion of an overlash on a particular pole. Within ninety (90) days of receiving such notice, Company will perform an inspection at Operator's expense to determine whether the overlash caused any damage to Company property or resulted in any code violations. Company shall notify Operator of any damage to Company property or code violations within fourteen (14) days after completion of the inspection. At Company's discretion, Company may either: (1) complete any necessary remedial work and bill Operator for the costs related to fixing the damage or correcting the code violations; or (2) require Operator to fix the damage or code violations at its own expense within fourteen (14) days' notice from Company.

10. Pole Installation or Replacement; Rearrangements; Guying

In any case Operator proposes to install Attachments on a pole to be erected by Company in a new location, and such pole must, in Company's judgment, be taller and/or stronger than would be necessary to accommodate the facilities of Company and of other persons who have previously indicated that they desire to make attachments on such pole or with whom Company has an agreement providing for joint or shared ownership of poles, the cost of such extra height and/or strength shall be paid to Company by Operator. Such cost shall be the difference between the cost in place of the new pole and the current cost in place of a pole considered by Company to be adequate for the facilities of Company and the attachments of such other persons.

Where in Company's judgment a new pole must be erected to replace an existing pole solely to adequately provide for Operator's proposed Attachments, Operator agrees to pay Company for the entire cost of the new pole necessary to accommodate the existing facilities on the pole and Operator's proposed Attachments, plus the cost of removal of the in-place pole, minus the salvage value, if any, of the removed pole. Operator shall also pay to Company and to any other owner of existing attachments on the pole the cost of transferring each of their respective facilities or attachments to the newly-installed pole.

If Operator's desired Attachments can be accommodated on existing poles of Company by rearranging facilities of Company thereon or of any other person, or if because of Operator's proposed Attachments it is necessary for Company to rearrange its facilities on any pole not owned by it, then in any such case, Operator shall reimburse Company and any such other person for the respective expense incurred in making such rearrangement.

If because of the requirements of its business, Company intends to replace an existing pole on which Operator has any Attachment, or Company intends to change the arrangements of its facilities on any such pole in such manner as to necessitate a rearrangement of Operator's Attachment, or if as a result of any inspection of Operator's Attachments Company determines that any such Attachments are not in accordance with Company's standards, applicable codes or the provisions of this Tariff or are otherwise hazards Company shall give Operator not less than sixty (60) days' notice of such proposed replacement or change, or any such violation or hazard; provided, however, that the sixty (60) day notice requirement shall not apply to: (1) make-ready notices pursuant to Section 4 of 807 KAR 5:015 or 807 KAR 5:015E (during the period such emergency regulation is effective); (2) routine maintenance by Company; or (3) a replacement or change made by Company in response to an emergency. In such event, Operator shall at its expense relocate, rearrange or modify its Attachments at the time specified by Company. If Operator fails to do so, or if any such emergency makes notice impractical, Company shall perform such relocation or rearrangement and Operator shall reimburse Company for the reasonable cost thereof.

Any additional guying or anchors required by reason of the Attachments of Operator shall be provided at the expense of Operator and shall meet the requirements of all applicable codes or regulations and Company's generally applicable guying standards.

Continued on Sheet 12-6

Tariff P.A. Continued
(Pole Attachments)

11. Self-Help Remedy

If Company is unable to meet the timelines in 807 KAR 5:015 (or 807 KAR 5:015E during the period such emergency regulation is effective) for completing a survey or completing make-ready work above the Communications Space, and if Company lacks good and sufficient cause to deviate from such timelines, Operator may perform such work at its own expense using an Approved Contractor. Operator shall refer to Company's website for a list of Approved Contractors for specified purposes. Self-help is not available for pole replacements or for surveys or make-ready related to ducts. Operator shall provide written notice to Company at least one (1) week prior to performing surveys or performing make-ready above the Communications Space. Operator shall notify Company immediately if a survey or make-ready causes any property damage or an outage that is reasonably likely to interrupt Company's services.

12. One-Touch Make-Ready

For Attachments to Distribution Poles that require only "simple make-ready," as that term is defined in 807 KAR 5:015, Operator may elect to proceed with the one-touch make-ready (OTMR) process established in this Section 12, as opposed to the standard process set forth in Section 6 of this Tariff. To elect OTMR, Operator must clearly indicate in its application that it is electing the OTMR process. Operator shall not combine requests for "simple make-ready" and "complex make-ready," as those terms are defined in 807 KAR 5:015, within an OTMR application. Operator's OTMR application shall identify the "simple make-ready" that it intends to perform.

Company shall, within ten (10) days of receipt, determine whether Operator's OTMR application is complete. Upon receipt of a complete OTMR application, Company shall review such application on the merits within the timelines established by 807 KAR 5:015. If Company denies an OTMR application on the merits, Company will provide Operator with an explanation of its denial, along with information and documentation supporting Company's decision.

Operator shall be responsible for all surveys required as part of the OTMR process. Any survey performed under the OTMR process shall be conducted by an Approved Contractor. Operator shall provide Company, as well as any third parties with attachments on Distribution Poles subject to an OTMR application, at least five (5) days' advance written notice of any field inspection, and such notice shall: provide the date, time and location of the field inspection; and state the name of the Approved Contractor that will be performing the field inspection. Operator shall allow Company and affected third parties to be present for any field inspection it performs under the OTMR process.

If Operator's OTMR application is approved, Operator may, after providing fifteen (15) days' advance written notice to Company and affected third parties, proceed with the make-ready as allowed by 807 KAR 5:015. Operator's notice shall: provide the date, time and location of the make-ready; describe the make-ready involved; and identify the contractor that will be performing the make-ready. Operator shall allow Company and affected third parties to be present during the make-ready. Operator shall complete all make-ready within thirty (30) days of the date on which Company approved Operator's OTMR application (or within seventy-five (75) days in the case of a Larger Order), or else Operator's OTMR application will be deemed closed.

If Company or Operator determine at any time that make-ready does not qualify as "simple make-ready," Operator shall halt all make-ready on the impacted Distribution Poles. The make-ready on the impacted Distribution Poles shall thereafter be subject to the requirements of Section 6 of this Tariff. Operator shall notify Company and affected third parties within fifteen (15) days of completion of the make-ready identified in the OTMR application.

Continued on Sheet 12-7

Tariff P.A. Continued
(Pole Attachments)

13. Pole Inspection

Company may make periodic inspections, as conditions may warrant, for the purpose of determining compliance with the provisions of this Tariff. Company reserves the right to inspect each new or proposed installation of Operator on Company's Facilities. In addition, Company's right to make any inspections and any inspection made pursuant to such right shall not relieve Operator of any responsibility, obligation or liability assumed under this Tariff.

14. Transfer of Attachments to New Poles

Operator shall transfer its Attachments within sixty (60) days of receiving notice from Company (Transfer Period). If Operator fails to transfer its Attachments within the Transfer Period, Company may transfer the Attachments at Operator's sole risk and expense. Company may transfer Operator's Attachments prior to the expiration of the Transfer Period if an expedited transfer is necessary for safety or reliability purposes.

15. Attachment Inventory

Owner may conduct a complete field inventory for the purpose of verifying the number and location of Operator's Attachments on Company Facilities. Company shall provide Operator with at least thirty (30) days' prior notice of a field inventory, and Operator shall advise Company whether Operator desires to participate in the field inventory not less than fifteen (15) days prior to the scheduled date of such inventory. Operator shall reimburse Company for the costs Company incurs in performing the field inventory, regardless of whether Operator elects to participate in the inventory; provided, however, Company may not charge Operator for more than one (1) complete field inventory within a five (5) year period. If Company inspects the Attachments of more than one Operator during a field inventory, then each Operator whose Attachments were inspected by Company during the field inventory shall share pro rata in the costs of such inventory. Upon request, Company shall furnish a summary report for the field inventory within a reasonable time after its completion.

If a field inventory reveals that the number of Operator's Attachments exceeds the number of Attachments shown in Company's existing records, the excess number of Attachments shall be presumed to be unauthorized attachments and handled in accordance with Section 16.

16. Unauthorized Attachments

If Operator makes an Attachment that requires approval by, or advance notice to, Company under this Tariff, and if Operator fails to comply with such approval or notice requirements, then Operator's Attachment shall be deemed an unauthorized attachment. Unless Operator can demonstrate to Company's reasonable satisfaction that an unauthorized attachment was made more recently, unauthorized attachments are presumed to have existed on Company Facilities for two (2) years. Operator shall be liable for all charges and fees that would have been due under the Tariff for this time period. In addition to charges and fees applicable to the period of unauthorized attachment, Operator shall pay a penalty in the amount of: (1) $25 for each unauthorized attachment within the Communications Space on a Distribution Pole; (2) $500 for each unauthorized attachment above the Communications Space on a Distribution Pole; and (3) $500 for each unauthorized attachment within a duct. Operator shall submit an application for approval of any unauthorized attachment within sixty (60) days of discovery. If Operator fails to submit the required application or to comply with Company's application process, Company may remove the unauthorized attachment at Operator's sole risk and expense.

17. Abandonment by Operator

Operator may at any time abandon the use of a Company Facility hereunder by removing therefrom all of its Attachments and by giving written notice thereof, on a form provided by Company, and no Facility shall be considered abandoned until such notice is received. If notice has been given that Attachment(s) have been removed, but the Attachments are later discovered not to have been removed, then such Attachments shall be deemed unauthorized attachments and handled in accordance with Section 16 of this Tariff.

Continued on Sheet 12-8

Tariff P.A. Continued
(Pole Attachments)

18. Indemnity

Operator hereby agrees to indemnify, hold harmless, and defend Company from and against any and all loss, damage, cost or expense which Company may suffer or for which Company may be held liable because of interruption of Operator's service to its subscribers, or by reason of bodily injury, including death, to any person, or damage to or destruction of any property, including loss of use thereof, arising out of or in any manner connected with the attachment, operation, and maintenance of the Attachments and other facilities of Operator on the Facilities of Company under this Tariff, or to any such act or omission of Operator's respective representatives, employees, agents or contractors.

19. Limitation of Liability

IN NO EVENT SHALL COMPANY OR ANY OF ITS REPRESENTATIVES BE LIABLE UNDER THIS TARIFF TO OPERATOR FOR CONSEQUENTIAL, INDIRECT, INCIDENTAL, SPECIAL, EXEMPLARY, PUNITIVE OR ENHANCED DAMAGES, LOST PROFITS OR REVENUES OR DIMINUTION IN VALUE, ARISING OUT OF, OR RELATING TO, OR IN CONNECTION WITH THIS TARIFF, REGARDLESS OF (A) WHETHER SUCH DAMAGES WERE FORESEEABLE; (B) WHETHER OR NOT COMPANY WAS ADVISED OF THE POSSIBILITY OF SUCH DAMAGES OR (C) THE LEGAL OR EQUITABLE THEORY (CONTRACT, TORT OR OTHERWISE) UPON WHICH THE CLAIM IS BASED. THE LIMITATIONS SET FORTH IN THIS SECTION 19 SHALL NOT APPLY TO DAMAGES OR LIABILITY ARISING FROM THE GROSSLY NEGLIGENT ACTS OR OMISSIONS OR WILLFUL MISCONDUCT OF COMPANY IN PERFORMING ITS OBLIGATIONS UNDER THIS TARIFF.

20. Insurance

Operator agrees to obtain and maintain at all times policies of insurance as follows:

(a) Comprehensive bodily injury liability insurance in an amount not less than $5,000,000 for any one occurrence.
(b) Comprehensive property damage liability insurance in an amount not less than $5,000,000 for any one occurrence.
(c) Contractual liability insurance in an amount not less than the foregoing minimums to cover the liability assumed by the Operator under the agreement or indemnity set forth above.

Prior to making Attachments to Company's Facilities, Operator shall furnish to Company two copies of a certificate, from an insurance carrier licensed to do business in Kentucky, stating that policies of insurance have been issued by it to Operator providing for the insurance listed above and that such policies are in force. Such certificate shall state that the insurance carrier will give Company thirty (30) days' prior written notice of any cancellation of or material change in such policies.

21. Performance Assurance

Operator shall furnish performance assurance in the following amounts to guarantee the payment of any sums which may become due for attachment charges, inspections, or work performed by Company under this Tariff, including the removal of Attachments upon termination of any license hereunder:

Number of Attachments	Amount per Attachment	Maximum Total
1-7,500	$20	$150,000
7,501-15,000	$10	$225,000
15,001+	$5	$1,000,000

Continued on Sheet 12-9

Tariff P.A. Continued
(Pole Attachments)

The above-stated amounts are incremental. By way of example, 10,000 Attachments would require performance assurance in the amount of $175,000 ($20 per Attachment for the first 7,500 Attachments; $10 per Attachment for the next 2,500 Attachments); 20,000 Attachments would require performance assurance in the amount of $250,000 ($20 per Attachment for the first 7,500 Attachments; $10 per Attachment the next 7,500 Attachments; and $5 per Attachment for the last 5,000 Attachments).

The amount of the performance assurance shall be calculated by Company annually based on Operator's then-existing number of Attachments. Operator shall provide the performance assurance within thirty (30) days of its request by Company.
If Operator proposes to attach a Wireless Facilities to Company Facilities, Operator shall provide performance assurance in the amount of $1,500 for each Company Facility to which a Wireless Facility is attached. The amount of the performance assurance shall not be reduced upon completion of installation or other event.

In the event the Operator provides performance assurance in the form of a surety bond or letter of credit, each bond or letter of credit shall contain the provision that it shall not be terminated prior to six (6) months after Company's receipt of written notice of the desire of the bonding or insurance company, or bank, to terminate such bond or letter of credit. Company may waive this requirement if an acceptable replacement is received before the six (6) months has ended. Upon termination of such surety bond or letter of credit, Company shall request Operator to immediately remove its Attachments and all other equipment from Company Facilities. If Operator should fail to complete the removal of all of its Attachments from Company Facilities within sixty (60) days after receipt of such request, then Company may remove Operator's Attachments at Operator's expense and without liability for any damage to Operator's Attachments.

Each surety bond shall be issued by an entity having a minimum A.M. Best rating of A- (and each letter of credit shall be issued by an entity having a minimum Credit Rating of A- by S& P or A3 by Moody's at the time of issuance and at all times the relevant instrument is outstanding.

22. Easements
Operator shall secure any right, license or permit from any governmental body, authority or other person or persons which may be required for the construction or maintenance of Attachments of Operator. Company does not convey nor guarantee any easements, rights-of-way or franchises for the construction and maintenance of said Attachments. Operator hereby agrees to indemnify and save harmless Company from any and all claims, including the expenses incurred by Company to defend itself against such claims, resulting from or arising out of the failure of Operator to secure such right, license, permit or easement for the construction or maintenance of said Attachments on Company's poles.

23. Charges and Fees
Operator agrees to pay Company an annual charge per Attachment as set forth in Section 3 of this Tariff in advance, and such other charges as may be provided for herein, for the use of each of Company Facility, any portion of which is occupied by, or reserved at Operator's request for, the Attachments of Operator.

Operator agrees to reimburse Company for all reasonable non-recurring expenses caused by or attributable to Operator's initial Attachments including without limitation the amounts set forth herein. Operator further agrees to reimburse the expenses of Company in examining poles used but not owned by Company to which Operator proposes to make Attachments.

24. Fees for Additional Attachments
For Attachments made to Company Facilities between billing dates, Operator shall be billed a prorated amount of the annual charge effective on the date of attachment on the Operator's next bill. Company will not reimburse Operator for, or otherwise prorate Operator's next bill for, any Attachments removed from Company Facilities between billing dates.

Continued on Sheet 12-10

Tariff P.A. Continued
(Pole Attachments)

25. Payment

Payment of amounts due hereunder is due on the dates or at the times indicated with respect to each such payment. In the event the time for any payment is not specified, such payment shall be due thirty (30) days from the date of the invoice therefor. All amounts not so paid shall accrue interest at a monthly simple interest rate of 1.5% . Where the provisions of the Tariff require any payment by Operator to the Company other than for attachment charges, Company may, at its option, require that the estimated amount thereof be paid in advance of permission to use any pole or the performance by Company of any work. In such a case, Company may, in its sole discretion, invoice any deficiency or refund any excess to Operator after the current amount of such payment has been determined.

26. Default or Non-Compliance

If Operator fails to comply with any of the provisions of this Tariff or defaults in the performance of any of its obligations under this Tariff and fails within sixty (60) days, after written notice from Company to correct such default or non-compliance, Company may, in addition to all other remedies under this Tariff, take any one or more of the following actions: terminate the specific permit or permits covering the Company Facilities to which such default or non-compliance is applicable; remove, relocate or rearrange Attachments of Operator to which such default or non-compliance relates, all at Operator's expense; decline to permit additional Attachments hereunder until such default is cured; or in the event of any failure to pay any of the charges, fees or amounts provided in this Tariff or any other substantial default, or of repeated defaults, terminate Operator's right of attachment. Where applicable, Company's written notice of default or non-compliance shall inform Operator of Company's right to remove, relocate or rearrange Attachments of Operator, in the event Operator fails to cure its default or non-compliance within the aforementioned 60-day period. Operator shall remove all Attachments where Company has terminated the right of attachment herein within sixty (60) days of Company providing notice of termination. If Operator fails to remove such Attachments within sixty (60) days, then Company may remove such Attachments at Operator's expense. Company shall have no obligation to store or recover any value for such removed Attachments.

No liability shall be incurred by Company because of any or all such actions except for Company's gross negligence or willful misconduct in any relocation or removal of such equipment. The remedies provided herein are cumulative and in addition to any other remedies available to Company.

27. Notices

Any notice required by this Tariff shall be deemed properly given if sent to Company's or Operator's authorized representative using any of the following methods: (1) overnight delivery by nationally recognized courier; (2) certified U.S. mail, return receipt requested, postage prepaid; (3) electronically via telecopier or electronic mail; or (4) sent in the manner expressly required herein or by Company's standards. Operators shall, within thirty (30) days of the effective date of this Tariff, or if service is taken for the first time following the effective date of this Tariff, prior to submitting any applications for Attachments, provide Company with the following information for each of their authorized representatives: name, title, mailing address and electronic mailing address. The designation of an authorized representative, as well as the contact information for an existing authorized representative, may be changed at any time by similar notice. Operators are required to maintain current contact information with Company for each of their authorized representatives.

28. Prior Agreements

This Tariff, as of the effective date, terminates, supersedes and replaces any previous agreement or license affecting Company's Facilities and Operator's Attachments covered herein.

Continued on Sheet 12-11

T

Tariff P.A. Continued
(Pole Attachments)

T

29. Assignment

This Tariff shall be binding upon and inure to the benefits of the parties hereto, their respective successors and/or assigns, but Operator shall not assign, transfer or sublet any of the rights hereby granted without the prior written consent of Company, which shall not be unreasonably withheld, and any such purported assignment, transfer or subletting without such consent shall be void.

30. Performance Waiver

Neither party shall be considered in default in the performance of its obligations herein, or any of them, to the extent that performance is delayed or prevented due to causes beyond the control of said party, including but not limited to, Acts of God or the public enemy, war, revolution, civil commotion, blockade or embargo, acts of government, any law, order, proclamation, regulation, ordinance, demand, or requirement of any government, fires, explosions, cyclones, floods, unavoidable casualties, quarantine, restrictions, strikes, labor disputes, lock-outs, and other causes beyond the reasonable control of either of the parties.

31. Preservation of Remedies

No delay or omission in the exercise of any power or remedy herein provided or otherwise available to the Company shall impair or affect its right thereafter to exercise the same.

Tariff T.S.
(Temporary Service)

Availability of Service
Where capacity is available, Company will install service for temporary lighting and power service to customers who have demonstrated to the Company's satisfaction that the requested temporary service will be temporary in nature. Residential customers will be supplied with 100 amp single phase service. All other customer classes will be supplied at voltage levels applicable to the class of business.

Rate *(Tariff Code 019)*
Temporary service will be supplied under any published tariff applicable to the class of business of the Customer, when the Company has available unsold capacity of lines, transforming and generating equipment, with an additional charge of the total cost of installation, connection, disconnection and removal of service.

Charges
The same minimum charge as provided for in any applicable tariff shall be applicable to such temporary service and for not less than one full monthly minimum.

Customer's requesting temporary service will be charged a minimum temporary service installation charge, payable in advance, based on the Company's actual cost of installation, connection, disconnection, and removal of the required facilities to provide temporary service.

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. T

Terms of Service
Temporary Service will be in effect for a period of 180 days from the date of installation. The Company may grant extensions based on customer's demonstration of continued need for temporary service.

The Company may discontinue temporary service at the end of the 180 days, or at the end of any extended period of time after the initial 180 days.

Special Terms and Conditions
A deposit equal to the full estimated amount of the bill and/or construction costs under this tariff may be required. This tariff is not available to customers permanently located, whose energy requirements are of a seasonal nature. See Terms and Conditions of Service.

Tariff U.D.C.
(Underground Differential Cost Schedule)

Underground Service Plan for Residential Subdivisions and Residential Service Laterals

Applicable
To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D. 2, and R.S.D.

Rate

PRIMARY AND SECONDARY DISTRIBUTION SYSTEM

Charge: $71.15 per foot of lot width (average x number of lots) when Company performs Trenching, conduit installation, and backfilling to Company specifications.

Charge: $32.50 per foot of lot width (average x number of lots) when Customer performs trenching, conduit installation, and backfilling to Company specifications.

SERVICE LATERALS

FROM OVERHEAD FACILITIES

Charge: $32.72 per foot of trench length from Overhead Facilities when Company performs trenching, conduit installation, and backfilling to Company specifications.

Charge: $11.49 per foot of trench length from Overhead Facilities when Customer performs trenching, conduit installation, and backfilling to Company specifications.

FROM UNDERGROUND FACILITIES

Charge: $25.35 per foot of trench length from Underground Facilities when Company performs trenching, conduit installation, and backfilling to Company specifications.

Charge: $4.66 per foot of trench length from Underground Facilities when Customer performs trenching, conduit installation, and backfilling to Company specifications.

REPLACEMENT OF USEFUL OVERHEAD SERVICE DROP

Charge: $180.00 for each removal in addition to any underground differential

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Rider A.F.S.
(Alternate Feed Service Rider)

Availability of Service

Standard Alternate Feed Service (AFS) is a premium service providing a redundant distribution service provided through a redundant distribution line and distribution station transformer, with automatic or manual switch-over and recovery, which provides increased reliability for distribution service. Rider AFS applies to those customers requesting new or upgraded AFS after the effective date of this rider. Rider AFS also applies to existing customers that desire to maintain redundant service when the Company must make expenditures in order to continue providing such service.

Rider AFS is available to customers who request a primary voltage alternate feed and who normally take service under Tariffs M.G.S.-TOD, L.G.S., L.G.S.-TOD, I.G.S., or M.W. for their basic service requirements, provided that the Company has adequate capacity in existing distribution facilities, as determined by the Company, or if changes can be made to make capacity available. AFS provided under this rider may not be available at all times, including emergency situations.

System Impact Study Charge

The Company shall charge the customer for the actual cost incurred by the Company to conduct a system impact study for each site reviewed. The study will consist of, but is not limited to, the following: (1) identification of customer load requirements, (2) identification of the potential facilities needed to provide the AFS, (3) determination of the impact of AFS loading on all electrical facilities under review, (4) evaluation of the impact of the AFS on system protection and coordination issues including the review of the transfer switch, (5) evaluation of the impact of the AFS request on system reliability indices and power quality, (6) development of cost estimates for any required system improvements or enhancements required by the AFS, and (7) documentation of the results of the study. The Company will provide to the customer an estimate of charges for this study.

Equipment and Installation Charge

The customer shall pay, in advance of construction, a nonrefundable amount for all equipment and installation costs for all dedicated and/or local facilities provided by the Company required to furnish either a new or upgraded AFS. The payment shall be grossed-up for federal and state taxes, assessment fees and gross receipts taxes. The customer will not acquire any title in said facilities by reason of such payment. The equipment and installation charge shall be determined by the Company and shall include, but not be limited to, the following: (1) all costs associated with the AFS dedicated and/or local facilities provided by the Company and (2) any costs or modifications to the customer's basic service facilities.

The customer is responsible for all costs associated with providing and maintaining phone service for use with metering to notify the Company of a transfer of service to the AFS or return to basic service.

Transfer Switch Provision

In the event the customer receives basic service at primary voltage, the customer shall install, own, maintain, test, inspect, operate and replace the transfer switch. Customer-owned switches are required to be at primary voltage and must meet the Company's engineering, operational and maintenance specifications. The Company reserves the right to inspect the customer-owned switches periodically and to disconnect the AFS for adverse impacts on reliability or safety.

Existing AFS customers, who receive basic service at primary voltage and are served via a Company-owned transfer switch and control module, may elect for the Company to continue ownership of the transfer switch. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, the customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer shall pay a monthly rate of $15.75 for the Company to annually test the transfer switch / control module and the customer shall reimburse the Company for the actual costs involved in maintaining the Company-owned transfer switch and control module.

Continued on Sheet 15-2

Rider A.F.S. Continued
(Alternate Feed Service Rider)

Transfer Switch Provision Continued

In the event a customer receives basic service at secondary voltage and requests AFS, the Company will provide the AFS at primary voltage. The Company will install, own, maintain, test, inspect and operate the transfer switch and control module. The customer shall pay the Company a nonrefundable amount for all costs associated with the transfer switch installation. The payment shall be grossed-up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer is required to pay the monthly rate for testing and ongoing maintenance costs defined above. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes.

After a transfer of service to the AFS, a customer utilizing a manual or semi-automatic transfer switch shall return to the basic service within one (1) week or as mutually agreed to by the Company and customer. In the event system constraints require a transfer to be expedited, the Company will endeavor to provide as much advance notice as possible to the customer. However, the customer shall accomplish the transfer back to the basic service within ten minutes if notified by the Company of system constraints. In the event the customer fails to return to basic service within 12 hours, or as mutually agreed to by the Company and customer, or within ten minutes of notification of system constraints, the Company reserves the right to immediately disconnect the customer's load from the AFS source. If the customer does not return to the basic service as agreed to, or as requested by the Company, the Company may also provide 30 days' notice to terminate the AFS agreement with the customer.

The customer shall make a request to the Company for approval three days in advance for any planned switching.

Monthly AFS Capacity Reservation Demand Charge
Monthly AFS charges will be in addition to all monthly basic service charges paid by the customer under the applicable tariff.

The Monthly AFS Capacity Reservation Demand Charge for the reservation of distribution station and primary lines is $6.38 per kW.

AFS Capacity Reservation
The customer shall reserve a specific amount of AFS capacity equal to, or less than, the customer's average maximum requirements, but in no event shall the customer's AFS capacity reservation under this rider exceed the capacity reservation for the customer's basic service under the appropriate tariff. The Company shall not be required to supply AFS capacity in excess of that reserved except by mutual agreement.

If the customer plans to increase the AFS demand at anytime in the future, the customer shall promptly notify the Company of such additional demand requirements. The customer's AFS capacity reservation and billing will be adjusted accordingly. The customer will pay the Company the actual costs of any and all additional dedicated and/or local facilities required to provide AFS in advance of construction and pursuant to an AFS construction agreement. If customer exceeds the agreed upon AFS capacity reservation, the Company reserves the right to disconnect the AFS. If the customer's AFS metered demand exceeds the agreed upon AFS capacity reservation, which jeopardizes company facilities or the electrical service to other customers, the Company reserves the right to disconnect the AFS immediately. If the Company agrees to allow the customer to continue AFS, the customer will be required to sign a new AFS agreement reflecting the new AFS capacity reservation. In addition, the customer will promptly notify Kentucky Power regarding any reduction in the AFS capacity reservation.

Continued on Sheet 15-3

Rider A.F.S. Continued
(Alternate Feed Service Rider)

The customer may reserve partial-load AFS capacity, which shall be less than the customer's full requirements for basic service subject to the conditions in this provision. Prior to the customer receiving partial-load AFS capacity, the customer shall be required to demonstrate or provide evidence to the Company that they have installed demand-controlling equipment that is capable of curtailing load when a switch has been made from the basic service to the AFS. The Company reserves the right to test and verify the customer's ability to curtail load to meet the agreed upon partial-load AFS capacity reservation.

Determination of Billing Demand

Full-Load Requirement:

For customers requesting AFS equal to their load requirement for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly billing demand on the AFS during the past 11 months, or (c) the customer's basic service capacity reservation, or (d) the customer's highest previously established monthly billing demand on the basic service during the past 11 months.

Partial-Load Requirement:

For customers requesting partial-load AFS capacity reservation that is less than the customer's full requirements for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak on the AFS as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly metered demand on the partial-load AFS during the past 11 months.

Delayed Payment Charge

Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. T

Terms of Contract

The AFS agreement under this rider will be made for a period of not less than one year and shall remain in effect thereafter until either party shall give at least six months' written notice to the other of the intention to discontinue service under the terms of this rider.

Disconnection of AFS under this rider due to reliability or safety concerns associated with customer-owned transfer switches will not relieve the customer of payments required hereunder for the duration of the agreement term.

Special Terms and Conditions

This rider is subject to the Company's Terms and Conditions of Service.

Upon receipt of a request from the customer for non-standard AFS (AFS which includes unique service characteristics different from standard AFS), the Company will provide the customer with a written estimate of all costs, including system impact study costs, and any applicable unique terms and conditions of service related to the provision of the non-standard AFS. An AFS agreement will be filed with the Commission under the 30-day filing procedures. The AFS agreement shall provide full disclosure of all rates, terms and conditions of service under this rider, and any and all agreements related thereto.

The Company will have sole responsibility for determining the basic service circuit and the AFS circuit.

The Company assumes no liability should the AFS circuit, transfer switch, or other equipment required to provide AFS fail to operate as designed, is unsatisfactory, or is not available for any reason.

Rider R.P.O.
(Renewable Power Option Rider)

Availability of Service

Available to customers taking metered service under the Company's R.S., R.S.D. , R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., and M.W. tariffs.

Participation in this program under Option A may be limited by the ability of the Company to procure renewable energy certificates (RECs) from Renewable Resources. If the total of all kWh under contract under this Rider equals or exceeds the Company's ability to procure RECs, the Company may suspend the availability of this Rider to new participants.

Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand.

Conditions of Service

Customers who wish to support the development of electricity generated by Renewable Resources may under Option A contract to purchase each month a specific number of fixed kWh blocks, or choose to cover all of their monthly usage.

Renewable Resources shall be defined as Wind, Solar Photovoltaic, Biomass Co-Firing of Agricultural crops and all energy crops, Hydro (as certified by the Low Impact Hydro Institute), Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-Firing of All Woody Waste including mill residue, but excluding painted or treated lumber. All REC's purchased under Option A of this tariff shall be retained or retired by the Company on behalf of customers.

Rates

Option A

In addition to the monthly charges determined according to the Company's tariff under which the customer takes metered service, the customer shall also pay the following rate for the REC option of their choosing. The charge will be applied to the customer's bill as a separate line item.

The Company will provide customers at least 30-days' advance notice of any change in the Rate. At such time, the customer may modify or cancel their automatic monthly purchase agreement. Any cancellation will be effective at the end of the current billing period when notice is provided.

	Block Purchase Charge ($ per 100 kWh block)	**All Usage Purchase Charge per kWh consumed**
A1. Solar RECs	$0.50/month	$0.005
A2. Wind RECs	$0.50/month	$0.005
A3. Hydro & Other RECs	$0.50/month	$0.005

Option B

Charges for service under option B of this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the firm service rates otherwise available to the Customer and the cost of the renewable energy resource being directly contracted for by the Customer.

Continued on Sheet 16-2

Rider R.P.O. Continued
(Renewable Power Option Rider)

Term
This is a voluntary program.

Under Option A Customers may participate through a one-time purchase, or establish an automatic monthly purchase agreement. Any payments under this program are nonrefundable. Customers participating under Option A may terminate service under this Rider by notifying the Company with at least thirty (30) days prior notice.

Under Option B, the term of the agreement will be determined in the written agreement between the Company and the Customer.

Special Terms and Conditions
This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. The Company may deny or terminate service under this Rider to customers who are delinquent in payment to the Company.

Funds collected under this Renewable Power Option Rider will be used solely to purchase RECs for the program.

Tariff N.U.G.
(Non-Utility Generator)

Availability of Service

This tariff is unavailable to new participants. This tariff is applicable to customers with generation facilities which have a total design capacity of over 1,000 kW that intends to schedule, deliver and sell the net electric output of the facility at wholesale, and who require Station Power service from the Company.

Service to any load that is electrically isolated from the Customer's generator shall be separately metered and provided in accordance with the generally available demand-metered tariff appropriate for such service to the Customer.

This tariff is not available for standby, backup, maintenance, or supplemental service for wholesale or retail loads served by Customer's generator.

Definitions

Station Power - The electrical energy and capacity supplied to the customer to serve the auxiliary loads at the Customer's generation facilities, usually when the Customer's generator is not operating. Station Power does not include Startup Power.

Station Power Service

Customers requiring Station Power shall take service under the generally available demand-metered tariff appropriate for the Customer's Station Power requirements.

Station Contract Capacity – The Customer shall contract for a definite amount of electrical capacity in kW sufficient to meet the maximum Station Power requirements that the Company is expected to supply under the generally available demand-metered tariff appropriate for the customer.

Transmission Service

Transmission Provider - The entity providing transmission service to customers in the Company's service territory. Such entity may be the Company or a regional transmission entity.

Prior to taking service under this tariff, the Customer must have a fully executed Interconnection and Operation Agreement with the Company and/or the Transmission Provider or an unexecuted agreement filed with the Federal Energy Regulatory Commission under applicable procedures.

Transmission Congestion is the condition that exists when market participants seek to dispatch in a pattern that would result in power flows that cannot be physically accommodated by the system.

Term of Contract

Contracts under this tariff will be made for an initial period of not less than one year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than one year.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

Continued on Sheet 17-2

Tariff N.U.G. Continued
(Non-Utility Generator)

The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement. Contracts will be made in multiples of 100 kW.

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. T

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff shall not obligate the Company to purchase or pay for any capacity or energy produced by the Customer's generator.

Customers desiring to provide Station Power from other generation facilities, owned by the same individual business entity that are not located on the site of the customer's generator (remote self-supply), shall take service under the terms and conditions contained within the applicable Open Access Transmission Tariff as filed with and accepted by the Federal Energy Regulatory Commission.

Tariff N.M.S.
(Net Metering Service)

Availability of Service

Net Metering is available to eligible customer-generators in the Company's service territory, upon request, and on a first-come, first-served basis up to a cumulative capacity of one percent (1%) of the Company's single hour peak load in Kentucky during the previous year. If the cumulative generating capacity of net metering systems reaches 1% of the Company's single hour peak load during the previous year, upon Commission approval, the Company's obligation to offer net metering to a new customer-generator may be limited. An eligible customer- generator shall mean a retail electric customer of the Company with a generating facility that:

(1) Generates electricity using solar energy, wind energy, biomass or biogas energy, or hydro energy;
(2) Has a rated capacity of not greater than forty-five (45) kilowatts;
(3) Is located on the customer's premises;
(4) Is owned and operated by the customer;
(5) Is connected in parallel with the Company's electric distribution system; and
(6) Has the primary purpose of supplying all or part of the customer's own electricity requirements.

At its sole discretion, the Company may provide Net Metering to other customer-generators not meeting all the conditions listed above on a case-by-case basis.

Eligible electric generating facilities in service before May 15, 2021 shall be entitled to continue to take service under this tariff, as it may be amended from time to time by the Commission, until the earlier of: (i) May 14, 2046; or (ii) the date the customer's modification of the eligible electric generating facility results in a material increase in the eligible electric generating facility's capacity.

The term "Customer" hereinafter shall refer to any customer requesting or receiving Net Metering services under this tariff.

Metering

Net energy metering shall be accomplished using a standard kilowatt-hour meter capable of measuring the flow of electricity in two (2) directions. If the existing electrical meter installed at the customer's facility is not capable of measuring the flow of electricity in two directions, the Company will provide the customer with the appropriate metering at no additional cost to the customer. If the customer requests any additional meter or meters or if distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

Billing/Monthly Charges

Monthly charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility. Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non- energy charge portions of the standard tariff bill. If the customer's net energy is negative during a billing period, the customer shall be credited in the next billing period for the kWh difference. If time-of-day metering is used, energy flows in both directions shall be netted and accounted for at the specific time-of-use in accordance with the provisions of the customer's standard tariff and this Net Metering Service Tariff. When the customer elects to no longer take service under this Net Metering Service Tariff, any unused credit shall revert to the Company. Excess electricity credits are not transferable between customers or locations.

Continued on Sheet 18-2

Tariff N.M.S. Continued
(Net Metering Service)

Application and Approval Process

The Customer shall submit an Application for Interconnection and Net Metering ("Application") and receive approval from the Company prior to connecting the generator facility to the Company's system.

Applications will be submitted by the Customer and reviewed and processed by the Company according to either Level 1 or Level 2 processes defined below.

The Company may reject an Application for violations of any code, standard, or regulation related to reliability or safety; however, the Company will work with the Customer to resolve those issues to the extent practicable.

Customers may contact the Company to check on the status of an Application or with questions prior to submitting an Application. Company contact information can be found on Kentucky Power Company's Application Form or on the Company's website.

Level 1 and Level 2 Definitions

Level 1

A Level 1 Application shall be used if the generating facility is inverter-based and is certified by a nationally recognized testing laboratory to meet the requirements of Underwriters Laboratories Standard 1741 "Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources" (UL 1741).

The Company will approve the Level 1 Application if the generating facility also meets all of the following conditions:

(1) For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
(2) If the proposed generating facility is to be interconnected on a single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generating facility, will not exceed the smaller of 20 kVA or the nameplate rating of the transformer.
(3) If the proposed generating facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.
(4) If the generating facility is to be connected to three-phase, three wire primary Company distribution lines, the generator shall appear as a phase-to-phase connection at the primary Company distribution line.
(5) If the generating facility is to be connected to three-phase, four wire primary Company distribution lines, the generator shall appear to the primary Company distribution line as an effectively grounded source.
(6) The interconnection will not be on an area or spot network.
(7) The Company does not identify any violations of any applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems."
(8) No construction of facilities by the Company on its own system will be required to accommodate the generating facility.

Continued on Sheet 18-3

Tariff N.M.S. Continued
(Net Metering Service)

Level 1 Continued
If the generating facility does not meet all of the above listed criteria, the Company, in its sole discretion, may either: 1) approve the generating facility under the Level 1 Application if the Company determines that the generating facility can be safely and reliably connected to the Company's system; or 2) deny the Application as submitted under the Level 1 Application.

The Company shall notify the customer within 20 business days whether the Application is approved or denied, based on the criteria provided in this section.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the time to process the Application.

When approved, the Company will indicate by signing the approval line on the Level 1 Application Form and returning it to the customer. The approval will be subject to successful completion of an initial installation inspection and witness test if required by the Company. The Company's approval section of the Application will indicate if an inspection and witness test are required. If so, the customer shall notify the Company within 3 business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within 10 business days of completion of the generator facility installation or as otherwise agreed to by the Company and the customer. The customer may not operate the generating facility until successful completion of such inspection and witness test, unless the Company expressly permits operational testing not to exceed two hours. If the installation fails the inspection or witness test due to noncompliance with any provision in the Application and Company approval, the customer shall not operate the generating facility until any and all noncompliance is corrected and re-inspected by the Company.

If the Application is denied, the Company will supply the customer with reasons for denial. The customer may resubmit under Level 2 if appropriate.

Level 2
A Level 2 Application is required under any of the following:

(1) The generating facility is not inverter based;
(2) The generating facility uses equipment that is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741; or
(3) The generating facility does not meet one or more of the additional conditions under Level 1.

The Company will approve the Level 2 Application if the generating facility meets the Company's technical interconnection requirements, which are based on IEEE 1547. The Company shall make its technical interconnection requirements available online and upon request.

The Company will process the Level 2 Application within 30 business days of receipt of a complete Application. Within that time the Company will respond in one of the following ways:

Continued on Sheet 18-4

Tariff N.M.S. Continued
(Net Metering Service)

(1) The Application is approved and the Company will provide the customer with an Interconnection Agreement to sign.
(2) If construction or other changes to the Company's distribution system are required, the cost will be the responsibility of the customer. The Company will give notice to the customer and offer to meet to discuss estimated costs and construction timeframe. Should the customer agree to pay for costs and proceed, the Company will provide the customer with an Interconnection Agreement to sign within a reasonable time.
(3) The Application is denied. The Company will supply the customer with reasons for denial and offer to meet to discuss possible changes that would result in Company approval. Customer may resubmit Application with changes.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the 30-business-day target to process the Application.

The Interconnection Agreement will contain all the terms and conditions for interconnection consistent with those specified in this tariff, inspection and witness test requirements, description of and cost of construction or other changes to the Company's distribution system required to accommodate the generating facility, and detailed documentation of the generating facilities which may include single line diagrams, relay settings, and a description of operation.

The customer may not operate the generating facility until an Interconnection Agreement is signed by the customer and Company and all necessary conditions stipulated in the agreement are met.

Application, Inspection and Processing Fees
No application fee or other review, study, or inspection or witness test fees will be charged by the company for Level I application.

The Company will require each customer to submit with each Level 2 Application a non-refundable application, inspection and processing fee of $50. In the event the Company determines an impact study is necessary with respect to a Level 2 Application, the customer shall be responsible for any reasonable costs up to $1,000 for the initial impact study. The Company shall provide documentation of the actual cost of the impact study. Any other studies requested by the customer shall be at the customer's sole expense.

Terms and Conditions for Interconnection
To interconnect to the Company's distribution system, the customer's generating facility shall comply with the following terms and conditions:

(1) The Company shall provide the customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

(2) The customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance and safe operation of the generating facility. Upon reasonable request from the Company, the customer shall demonstrate generating facility compliance.

Continued on Sheet 18-5

Tariff N.M.S. Continued
(Net Metering Service)

Terms and Conditions for Interconnection Continued

(3) The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by IEEE and accredited testing laboratories such as Underwriters Laboratories; (b) the NEC as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

(4) Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

(5) Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

(6) Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(7) After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance, and operation of the generating facility comply with the requirements of this tariff.

Continued on Sheet 18-6

Tariff N.M.S. Continued
(Net Metering Service)

Terms and Conditions for Interconnection Continued

(8) For Level 1 and 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring that the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

(9) Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability, or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

(10) Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity is allowed without approval.

(11) To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining, or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

Continued on Sheet 18-7

Tariff N.M.S. Continued
(Net Metering Service)

Terms and Conditions for Interconnection Continued T

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

(12) The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for both Level 1 and Level 2 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

(13) By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

(14) A customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

(15) The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Term of Contract

Any contract required under this tariff shall become effective when executed by both parties and shall continue in effect until terminated. The contract may be terminated as follows: (a) Customer may terminate the contract at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the contract or the rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service and all provisions of the standard service tariff under which the customer takes service. This tariff is also subject to the applicable provisions of the Company's Technical Requirements for Interconnection.

Continued on Sheet 18-8

Tariff N.M.S. Continued
(Net Metering Service)

Application For Interconnection And Net Metering – Level 1

Use this Application only for: 1.) a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741, 2.) less than or equal to 45 kW generation capacity and 3.) connecting to Kentucky Power distribution system.

Submit this Application to:

D.G. Coordinator
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoordinator@aep.com

(Contact person listed is subject to change. Please visit our website for up-to date information http://www.kentucky power.com)

Applicant

Name:

Mailing Address:

City: State: Zip:

Phone: ( ) Phone: ( )

E-mail address:

Service Location

Name:

Street Address:

City: State: Zip: Electric Service

Account Number

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Alternate Contacts

Name	Company	Telephone/Email

Continued on Sheet 18-9

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Tariff N.M.S. Continued
(Net Metering Service)

APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 1 – CONTINUED

Equipment Qualifications

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass
Inverter Manufacturer: Model:

Inverter Power Rating: Voltage Rating:

Power Rating of Energy Source (i.e., solar panels, wind turbine):
Battery Storage: ( ) Yes ( ) No If Yes, Battery Power Rating:

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: _____

Continued on Sheet 18-10

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1:

1 Kentucky Power Company (Company) shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

6 Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

Continued on Sheet 18-11

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 1 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity is allowed without approval.

Continued on Sheet 18-12

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for Level 1 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the Customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Continued on Sheet 18-13

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued
Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute. I hereby certify that, to the best of my knowledge, all of the information provided in this Application is true, and I agree to abide by all the Terms and Conditions included in this Application for Interconnection and Net Metering and Company's Net Metering Tariff.

Customer Signature: _____ **Date:** _____

COMPANY APPROVAL SECTION

When signed below by a Company representative, Application for Interconnection and Net Metering is approved subject to the provisions contained in this Application and as indicated below.

Company inspection and witness test: ( ) Required ( ) Waived

If Company inspection and witness test is required, Customer shall notify the Company within three (3) business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within ten (10) business days of completion of the generating facility installation or as otherwise agreed to by the Company and the Customer. Unless indicated below, the Customer may not operate the generating facility until such inspection and witness test is successfully completed. Additionally, the Customer may not operate the generating facility until all other terms and conditions in the Application have been met.
Call: _____ to schedule an inspection and witness test.

Pre-Inspection operational testing not to exceed two (2) hours: ( ) Allowed ( ) Not Allowed

If Company inspection and witness test is waived, operation of the generating facility may begin when installation is complete, and all other terms and conditions in the Application have been met.

Additions, Changes, or Clarifications to Application Information: ( ) None ( ) As specified here:

Approved by: _____ **Date**: _____

Printed Name: _____ **Title:** _____

Continued on Sheet 18-14

Tariff N.M.S. Continued
(Net Metering Service)

Application for Interconnection and Net Metering – Level 2

Use this Application form for connecting to the Kentucky Power distribution system and: 1.) the generating facility is not inverter based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or 2.) does not meet any of the additional conditions under a Level 1 Application (inverter based and less than or equal to 45kW generation).

Submit this Application (along with the application fee of $100) to:

D.G. Coordinator
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoordinator@aep.com

(Contact person listed is subject to change. Please visit our website for up-to date information http://www.kentucky power.com)

Applicant

Name:		
Mailing Address:		
City:	State:	Zip:
Phone: ( )		Phone: ( )
E-mail address:		

Service Location

Name:		
Street Address:		
City:	State:	Zip:
Electric Service Account Number		

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Alternate Contacts

Name	Company	Telephone/Email

Continued on Sheet 18-15

Tariff N.M.S. Continued
(Net Metering Service)

APPPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 2 - CONTINUED

Equipment Qualifications

Total Generating Capacity (kW) of the Generating Facility: _____

Type of Generator: ( ) Inverter-Based ( ) Synchronous ( ) Induction

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: _____

Continued on Sheet 18-16

Tariff N.M.S. Continued
(Net Metering Service)

Interconnection Agreement – Level 2

This Interconnection Agreement (Agreement) is made and entered into this _____ day of ___, 20__, by and between Kentucky Power Company (Company), and _____ (Customer). Company and Customer are hereinafter sometimes referred to individually as "Party" or collectively as "Parties"

Witnesseth:

Whereas, Customer is installing, or has installed, generating equipment, controls, and protective relays and equipment (Generating Facility) used to interconnect and operate in parallel with Company's electric system, which Generating Facility is more fully described in Exhibit A, attached hereto and incorporated herein by this Agreement, and as follows:

Location: _____

Generator Size and Type: _____

Now, Therefore, in consideration thereof, Customer and Company agree as follows:

Company agrees to allow Customer to interconnect and operate the generating Facility in parallel with the Company's electric system and Customer agrees to abide by Company's Net Metering Tariff and all Terms and Conditions listed in this Agreement including any additional conditions listed in Exhibit A.

Continued on Sheet 18-17

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2:

To interconnect to the Kentucky Power Company (Company) distribution system, the customer's generating facility shall comply with the following terms and conditions:

1. Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter/meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2. Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3. The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4. Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5. Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

Continued on Sheet 18-18

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

6. Customer shall be responsible for protecting, at Customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

7. After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8. For Level 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

   The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

Continued on Sheet 18-19

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

10. Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components not resulting in increases in generating facility capacity is allowed without approval.

11. To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

    The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12. The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy). Customer shall provide Company with proof of such insurance at the time that application is made for net metering.

13. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15. The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Continued on Sheet 18-20

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

IN WITNESS WHEREOF, the Parties have executed this Agreement, effective as of the date first above written.

Customer Signature:	_____	**Date:**	_____
Printed Name:	_____	**Title:**	_____
Company Signature:	_____	**Date:**	_____
Printed Name:	_____	**Title:**	_____

Continued on Sheet 18-21

T

Tariff N.M.S. Continued
(Net Metering Service)

T

Interconnection Agreement – Level 2
Exhibit A

- Exhibit A will contain additional detailed information about the Generating Facility such as a single line diagram, relay settings, and a description of operation.
- When construction of the Company's facilities is required, Exhibit A will also contain a description and associated cost.
- Exhibit A will also specify requirements for a Company inspection and witness test and when limited operation for testing or full operation may begin.

Tariff N.M.S. II
(Net Metering Service II)

Availability of Service

Net Metering is available to eligible customer-generators in the Company's service territory, upon request, and on a first-come, first-served basis up to a cumulative capacity of one percent (1%) of the Company's single hour peak load in Kentucky during the previous year. If the cumulative generating capacity of net metering systems reaches 1% of the Company's single hour peak load during the previous year, upon Commission approval, the Company's obligation to offer net metering to a new customer-generator may be limited. An eligible customer- generator shall mean a retail electric customer of the Company with a generating facility that:

(1) Generates electricity using solar energy, wind energy, biomass or biogas energy, or hydro energy;
(2) Has a rated capacity of not greater than forty-five (45) kilowatts;
(3) Is located on the customer's premises;
(4) Is owned and operated by the customer;
(5) Is connected in parallel with the Company's electric distribution system; and
(6) Has the primary purpose of supplying all or part of the customer's own electricity requirements.

At its sole discretion, the Company may provide Net Metering to other customer-generators not meeting all the conditions listed above on a case-by-case basis.

Eligible generating facilities may take service, for a period of 25 years after the eligible generating facility is first placed in service, under the two-part rate structure and netting periods of this tariff in effect at the time the eligible electric generating facility is first placed in service.

Customers served under this optional offering will not be eligible for the Company's Equal Payment Plan (Budget) or Average Monthly Payment Plan (AMP).

The term "Customer" hereinafter shall refer to any customer requesting or receiving Net Metering services under this tariff.

Metering

Net energy metering shall be accomplished using a time of use ("TOU") kilowatt-hour meter capable of measuring the flow of electricity in two (2) directions. If the existing electrical meter installed at the customer's facility is not capable of measuring the flow of electricity in two directions, the Company will provide the customer with the appropriate metering at no additional cost to the customer. If the customer requests any additional meter or meters or if distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

Billing Charges

All net billing kWh and kW in each netting period, accumulated for the billing period, shall be charged at the rates applicable under the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility.

Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non- energy charge portions of the standard tariff bill.

All excess customer generation, (net negative energy or "NNE"), accumulated for the billing period, shall be credited at the avoided cost rate of 0.09746 $/kWh for Residential service and 0.09657 $/kWh for non-residential service each billing period.

Continued on Sheet 19-2

Tariff N.M.S. II Continued
(Net Metering Service II)

Bill credits to customers for NNE at the avoided cost rate each billing period is a purchased power expense and shall be recovered from all customers through the Company's Purchased Power Adjustment Rider. If the NNE credit exceeds the customer's billed energy charges, along with any riders that are based on a per kWh charge, during the billing period, the amount in excess will be carried over for use in subsequent billing periods. Excess electricity credits are not transferable between customers or locations. When the customer elects to no longer take service under this Net Metering Service II Tariff, any unused credit shall revert to the Company. T

Application and Approval Process

The Customer shall submit an Application for Interconnection and Net Metering ("Application") and receive approval from the Company prior to connecting the generator facility to the Company's system.

Applications will be submitted by the Customer and reviewed and processed by the Company according to either Level 1 or Level 2 processes defined below.

The Company may reject an Application for violations of any code, standard, or regulation related to reliability or safety; however, the Company will work with the Customer to resolve those issues to the extent practicable.

Customers may contact the Company to check on the status of an Application or with questions prior to submitting an Application. Company contact information can be found on Kentucky Power Company's Application Form or on the Company's website.

Level 1 and Level 2 Definitions

Level 1

A Level 1 Application shall be used if the generating facility is inverter-based and is certified by a nationally recognized testing laboratory to meet the requirements of Underwriters Laboratories Standard 1741 "Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources" (UL 1741).

The Company will approve the Level 1 Application if the generating facility also meets all of the following conditions:

(1) For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
(2) If the proposed generating facility is to be interconnected on a single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generating facility, will not exceed the smaller of 20 kVA or the nameplate rating of the transformer.
(3) If the proposed generating facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.
(4) If the generating facility is to be connected to three-phase, three wire primary Company distribution lines, the generator shall appear as a phase-to-phase connection at the primary Company distribution line.
(5) If the generating facility is to be connected to three-phase, four wire primary Company distribution lines, the generator shall appear to the primary Company distribution line as an effectively grounded source.
(6) The interconnection will not be on an area or spot network.

Continued on Sheet 19-3

Tariff N.M.S. II Continued
(Net Metering Service II)

Level 1 Continued

(7) The Company does not identify any violations of any applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems."
(8) No construction of facilities by the Company on its own system will be required to accommodate the generating facility.

If the generating facility does not meet all of the above listed criteria, the Company, in its sole discretion, may either: 1) approve the generating facility under the Level 1 Application if the Company determines that the generating facility can be safely and reliably connected to the Company's system; or 2) deny the Application as submitted under the Level 1 Application.

The Company shall notify the customer within 20 business days whether the Application is approved or denied, based on the criteria provided in this section.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the time to process the Application.

When approved, the Company will indicate by signing the approval line on the Level 1 Application Form and returning it to the customer. The approval will be subject to successful completion of an initial installation inspection and witness test if required by the Company. The Company's approval section of the Application will indicate if an inspection and witness test are required. If so, the customer shall notify the Company within 3 business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within 10 business days of completion of the generator facility installation or as otherwise agreed to by the Company and the customer. The customer may not operate the generating facility until successful completion of such inspection and witness test, unless the Company expressly permits operational testing not to exceed two hours. If the installation fails the inspection or witness test due to noncompliance with any provision in the Application and Company approval, the customer shall not operate the generating facility until any and all noncompliance is corrected and re-inspected by the Company.

If the Application is denied, the Company will supply the customer with reasons for denial. The customer may resubmit under Level 2 if appropriate.

Level 2
A Level 2 Application is required under any of the following:

(1) The generating facility is not inverter based;
(2) The generating facility uses equipment that is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741; or
(3) The generating facility does not meet one or more of the additional conditions under Level 1.

The Company will approve the Level 2 Application if the generating facility meets the Company's technical interconnection requirements, which are based on IEEE 1547. The Company shall make its technical interconnection requirements available online and upon request.

The Company will process the Level 2 Application within 30 business days of receipt of a complete Application. Within that time the Company will respond in one of the following ways:

Continued on Sheet 19-4

Tariff N.M.S. II Continued
(Net Metering Service II)

Level 2 Continued

(1) The Application is approved and the Company will provide the customer with an Interconnection Agreement to sign.
(2) If construction or other changes to the Company's distribution system are required, the cost will be the responsibility of the customer. The Company will give notice to the customer and offer to meet to discuss estimated costs and construction timeframe. Should the customer agree to pay for costs and proceed, the Company will provide the customer with an Interconnection Agreement to sign within a reasonable time.
(3) The Application is denied. The Company will supply the customer with reasons for denial and offer to meet to discuss possible changes that would result in Company approval. Customer may resubmit Application with changes.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the 30-business-day target to process the Application.

The Interconnection Agreement will contain all the terms and conditions for interconnection consistent with those specified in this tariff, inspection and witness test requirements, description of and cost of construction or other changes to the Company's distribution system required to accommodate the generating facility, and detailed documentation of the generating facilities which may include single line diagrams, relay settings, and a description of operation.

The customer may not operate the generating facility until an Interconnection Agreement is signed by the customer and Company and all necessary conditions stipulated in the agreement are met.

Application, Inspection and Processing Fees

No application fee or other review, study, or inspection or witness test fees will be charged by the Company for Level 1 applications.

The Company will require each customer to submit with each Level 2 Application a non-refundable application, inspection and processing fee of $100. In the event the Company determines an impact study is necessary with respect to a Level 2 Application, the customer shall be responsible for any reasonable costs up to $1,000 for the initial impact study. The Company shall provide documentation of the actual cost of the impact study. Any other studies requested by the customer shall be at the customer's sole expense.

Terms and Conditions for Interconnection

To interconnect to the Company's distribution system, the customer's generating facility shall comply with the following terms and conditions:

(1) The Company shall provide the customer net metering services, without charge for standard TOU metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

(2) The customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance and safe operation of the generating facility. Upon reasonable request from the Company, the customer shall demonstrate generating facility compliance.

Continued on Sheet 19-5

Tariff N.M.S. II Continued
(Net Metering Service II)

Terms and Conditions for Interconnection Continued

(3) The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by IEEE and accredited testing laboratories such as Underwriters Laboratories; (b) the NEC as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

(4) Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

(5) Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

(6) Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(7) After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance, and operation of the generating facility comply with the requirements of this tariff.

Continued on Sheet 19-6

Tariff N.M.S. II Continued
(Net Metering Service II)

Terms and Conditions for Interconnection Continued

(8) For Level 1 and 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring that the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

(9) Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability, or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

(10) Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity are allowed without approval.

(11) To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining, or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

Continued on Sheet 19-7

Tariff N.M.S. II Continued
(Net Metering Service II)

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

(12) The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for both Level 1 and Level 2 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

(13) By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

(14) A customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

(15) The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Term of Contract

Any contract required under this tariff shall become effective when executed by both parties and shall continue in effect until terminated. The contract may be terminated as follows: (a) Customer may terminate the contract at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the contract or the rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service and all provisions of the standard service tariff under which the customer takes service. This tariff is also subject to the applicable provisions of the Company's Technical Requirements for Interconnection.

Continued on Sheet 19-8

Tariff N.M.S. II Continued
(Net Metering Service II)

Application For Interconnection And Net Metering – Level 1

Use this Application only for: 1.) a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741, 2.) less than or equal to 45 kW generation capacity, and 3.) connecting to Kentucky Power distribution system.

Submit this Application to:

D.G. Coordinator American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoodinator@aep.com

(Contact person listed is subject to change. Please visit our website for up-to-date information http://www.kentuckypower.com)

Applicant

Name:

Mailing Address:

City: State: Zip:

Phone: ( ) Phone: ( )

E-mail address:

Service Location

Name:

Street Address:

City: State: Zip:

Electric Service Account Number

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Alternate Contacts

Name	Company	Telephone/Email

Continued on Sheet 19-9

Tariff N.M.S. II Continued
(Net Metering Service II)

APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 1 – CONTINUED

Equipment Qualifications

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Inverter Manufacturer: Model:

Inverter Power Rating: Voltage Rating:

Power Rating of Energy Source (i.e., solar panels, wind turbine):

Battery Storage: ( ) Yes ( ) No If Yes, Battery Power Rating:

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: _____

Continued on Sheet 19-10

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1:

1 The Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

6 Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

Continued on Sheet 19-11

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1, continued

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 1 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity are allowed without approval.

Continued on Sheet 19-12

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1, continued

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for Level 1 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the Customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits ("RECs") that may be generated by their generating facility.

Continued on Sheet 19-13

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute. I hereby certify that, to the best of my knowledge, all of the information provided in this Application is true, and I agree to abide by all the Terms and Conditions included in this Application for Interconnection and Net Metering and Company's Net Metering Tariff.

Customer Signature: _____ **Date:** _____

COMPANY APPROVAL SECTION

When signed below by a Company representative, Application for Interconnection and Net Metering is approved subject to the provisions contained in this Application and as indicated below.

Company inspection and witness test: ( ) Required ( ) Waived

If Company inspection and witness test is required, Customer shall notify the Company within three (3) business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within ten (10) business days of completion of the generating facility installation or as otherwise agreed to by the Company and the Customer. Unless indicated below, the Customer may not operate the generating facility until such inspection and witness test is successfully completed. Additionally, the Customer may not operate the generating facility until all other terms and conditions in the Application have been met.
Call: to schedule an inspection and witness test.

Pre-Inspection operational testing not to exceed two (2) hours: ( ) Allowed ( ) Not Allowed

If Company inspection and witness test is waived, operation of the generating facility may begin when installation is complete, and all other terms and conditions in the Application have been met.

Additions, Changes, or Clarifications to Application Information: ( ) None ( ) As specified here:

_____

Approved by: _____ **Date**: _____

Printed Name: _____ **Title:** _____

Continued on Sheet 19-14

Tariff N.M.S. II Continued
(Net Metering Service II)

Application for Interconnection and Net Metering – Level 2

Use this Application form for connecting to the Kentucky Power distribution system and: 1.) the generating facility is not inverter based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or 2.) does not meet any of the additional conditions under a Level 1 Application (inverter based and less than or equal to 45kW generation).

Submit this Application (along with the application fee of $100) to:

D.G. Coordinator
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoordinator@aep.com

(Contact person listed is subject to change. Please visit our website for up-to date information http://www.kentucky power.com)

Applicant

Name:

Mailing Address:

City: State: Zip:

Phone: ( ) Phone: ( )

E-mail address:

Service Location

Name:

Street Address:

City: State: Zip:

Electric Service Account Number

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Alternate Contacts

Name	Company	Telephone/Email

Continued on Sheet 19-15

Tariff N.M.S. II Continued
(Net Metering Service II)

APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 2 - CONTINUED

Equipment Qualifications

Total Generating Capacity (kW) of the Generating Facility:

Type of Generator: ( ) Inverter-Based ( ) Synchronous ( ) Induction

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: _____

Continued on Sheet 19-16

Tariff N.M.S. II Continued
(Net Metering Service II)

Interconnection Agreement – Level 2

This Interconnection Agreement (Agreement) is made and entered into this _____ day of ___, 20__, by and between Kentucky Power Company (Company), and _____ (Customer). Company and Customer are hereinafter sometimes referred to individually as "Party" or collectively as "Parties"

Witnesseth:

Whereas, Customer is installing, or has installed, generating equipment, controls, and protective relays and equipment (Generating Facility) used to interconnect and operate in parallel with Company's electric system, which Generating Facility is more fully described in Exhibit A, attached hereto and incorporated herein by this Agreement, and as follows:

Location:_____

Generator Size and Type:_____

Now, therefore, in consideration thereof, Customer and Company agree as follows:

Company agrees to allow Customer to interconnect and operate the generating Facility in parallel with the Company's electric system and Customer agrees to abide by Company's Net Metering Tariff and all Terms and Conditions listed in this Agreement including any additional conditions listed in Exhibit A.

Continued on Sheet 19-17

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 2:

To interconnect to the Kentucky Power Company (Company) distribution system, the customer's generating facility shall comply with the following terms and conditions:

1. Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter/meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2. Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3. The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4. Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5. Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

Continued on Sheet 19-18

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 2, continued

6. Customer shall be responsible for protecting, at Customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

7. After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8. For Level 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

   The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS
   be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

Continued on Sheet 19-19

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 2, continued

10. Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components not resulting in increases in generating facility capacity are allowed without approval.

11. To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

    The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12. The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy). Customer shall provide Company with proof of such insurance at the time that application is made for net metering.

13. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15. The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Continued on Sheet 19-20

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 2, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

IN WITNESS WHEREOF, the Parties have executed this Agreement, effective as of the date first above written.

Customer Signature: _____ **Date:** _____

Printed Name: _____ **Title:** _____

Company Signature: _____ **Date:** _____

Printed Name: _____ **Title:** _____

Continued on Sheet 19-21

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Tariff N.M.S. II Continued
(Net Metering Service II)

T

Interconnection Agreement – Level 2
Exhibit A

- Exhibit A will contain additional detailed information about the Generating Facility such as a single line diagram, relay settings, and a description of operation.
- When construction of the Company's facilities is required, Exhibit A will also contain a description and associated cost.
- Exhibit A will also specify requirements for a Company inspection and witness test and when limited operation for testing or full operation may begin.

RESERVED FOR FUTURE USE

DT

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Tariff COGEN/SPP
(Cogeneration and/or Small Power Production--Over 45 KW)

T

Availability of Service

This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a net power production capacity of over 45 KW. In addition, cogeneration facilities must have a net power production capacity at or below 20,000 KW, and small power production facilities must have a net power production capacity at or below 5,000 KW. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel. T

The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:

Option 1 - The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 2 - The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 3 - The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

Monthly Charges for Delivery from the Company to the Customer

Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers with cogeneration and/or small power production facilities having a total design capacity of more than 10 KW shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3. T

Additional Charges

There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge

The additional monthly charge for special metering facilities shall be as follows:

Option 1 - Not Applicable

Option 2 & 3 - Where meters are used to measure the excess or total energy and average on peak capacity purchased by the Company:

	Single Phase	Polyphase
Standard Measurement	$9.25	$12.10
T.O.D. Measurement	$9.85	$12.40

Continued on Sheet 21-2

T

Tariff COGEN/SPP Continued
(Cogeneration and/or Small Power Production-- Over 45 KW)

Additional Charges Continued

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each case.

Local Facilities Charge
Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit.

Monthly Credits or Payments for Energy and Capacity Deliveries

Energy Credit
The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter – All KWH	Variable LMP at time of delivery ¢ KWH
T.O.D. Meter	
On-Peak KWH	Variable LMP at time of delivery ¢ KWH
Off-Peak KWH	Variable LMP at time of delivery ¢ KWH

Capacity Credit
If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used, $4.53 kW/month, times the lowest of: I D

1. monthly contract capacity, or
2. current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730,or
3. lowest average capacity metered during the previous two months if less than monthly contract capacity.

Continued on Sheet 21-3

Tariff COGEN/SPP Continued
(Cogeneration and/or Small Power Production-- Over 45 KW)

T

Monthly Credits or Payments for Energy and Capacity Deliveries Continued

If T.O.D. energy meters are used, $10.88 kW/month, times the lowest of: I D

1. on-peak contract capacity, or
2. current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by 305, or
3. lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

On-Peak and Off-Peak Periods

The on-peak period shall be defined as starting at 7:00 A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00 A.M., local time, Monday through Friday, and all hours of Saturday and Sunday.

Charges for Cancellation or Non Performance Contract

If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/ SPP or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract. T

Term of Contract

Contracts under this tariff shall be made for a term not less than five (5) years and no longer than twenty (20) years. A Qualifying Facility ("QF") can request that avoided cost rates be set on an "as available" basis or when a legally enforceable obligation is established. T

Continued on Sheet 21-4 T

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

T

Tariff COGEN/SPP Continued
(Cogeneration and/or Small Power Production-- Over 45 KW)

Term of Contract Continued

The Company shall not provide a prospective Cogen/SPP customer with a contract for service under this tariff until the customer has met the burden of establishing a legally enforceable obligation ("LEO") under PURPA. A LEO will be established for the Customer's facility when the following criteria have been met to the Company's satisfaction:

1. Documentation of having obtained Qualifying Facility status from FERC pursuant to the certification procedures set out in 18 CFR 292.207. QFs that "self-certify" must provide the Company with its submitted FERC Form No. 556 – Certification of QF Status for Small Power Production and Cogeneration Facilities.

2. Documentation provided to the electric utility of all of the following: (i) a description of the location of the project and its proximity to other projects within one mile of the project and within 10 miles of the project, which are owned or controlled by the same developer, and (ii) an estimated, non-binding, good faith estimate of the energy production for the project that includes the kilowatt-hours or megawatt hours to be produced by the QF for each month and year of the entire term of the project's anticipated avoided cost power purchase agreement.

3. Documentation of an interconnection application with the appropriate electric utility, and proof of payment of applicable application fees.

4. Documentation of meaningful steps to obtain site control adequate to commence construction of the project at the proposed location.

5. Documentation of all applications, including filing fees, to obtain all necessary local permitting and zoning approvals.

6. If qualifying as a "cogeneration facility" as defined by 18 CFR 292.202(c), written proof, provided to the electric utility, of a steam host that is willing to contract for steam over the full term of the project's anticipated power purchase agreement for a cogeneration facility.

7. Proof of a deposit, paid in full, to cover the estimated costs for a system impact or facilities study, such as an engineering review or distribution study, should a study or studies become necessary.

Tariff C.S.-I.R.P.
(Contract Service – Interruptible Power)

Availability of Service

Available for service to customers who contract for service under the Company's Industrial General Service (I.G.S.) tariff. The Company reserves the right to limit the total contract capacity for all customers served under this Tariff to 75,000 kW.

Loads of new customers locating within the Company's service area or load expansions by existing customers may be offered interruptible service as part of an economic development incentive. Such interruptible service shall not be counted toward the limitation on total interruptible power contract capacity, as specified above, and will not result in a change to the limitation on total interruptible power contract capacity.

Conditions of Service

The Company will offer eligible customers the option to receive interruptible power service. This interruptible service will be consistent with PJM's Load Management Resource Product – Capacity Performance Demand Response requirement, hereafter referred to as the "PJM Demand Response Program", subject to any limitations on the availability of that Program by PJM. To be eligible for the credit, customers must be able to provide interruptible load (not including behind the meter diesel generation) of at least one (1) MW at a single site and commit to a minimum four (4) year contract term. The contract shall provide that 90 days prior to each contract anniversary date, the customer shall re-nominate the amount of interruptible load for the upcoming contract year, except that the cumulative reductions over the life of the contract shall not exceed 20% of the original interruptible load nominated under the contract. If no re-nomination is received at least 90 days prior to the contract anniversary date, the prior year's interruptible load shall apply for the forthcoming contract year.

Upon receipt of a request from the Customer for interruptible service, the Company will provide the Customer with a written addendum containing the rates and related terms and conditions of service under which such service will be provided by the Company. If the parties reach an agreement based upon the offer provided to the Customer by the Company, such written contract will be filed with the Commission. The contract shall provide full disclosure of all rates, terms and conditions of service under this Tariff, and any and all agreements related thereto, subject to the designation of the terms and conditions of the contract as confidential, as set forth herein.

The Customer shall provide reasonable evidence to the Company that the Customer's electric service can be interrupted in accordance with the provisions of the written agreement including, but not limited to, the specific steps to be taken and equipment to be curtailed upon a request for interruption.

The Customer shall contract for capacity sufficient to meet average maximum interruptible power requirements, but in no event will the interruptible amount contracted for be less than 1,000 KW at any delivery point.

The Company reserves the right to test and verify the customer's ability to curtail. Any such test or verification may require actual physical interruption or curtailment, to the extent such testing or interruption is required under PJM's Demand Response Program.

NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS SCHEDULE.

Except as otherwise provided in the written agreement, the Company's Terms and Conditions of Service shall apply to service under this tariff.

Continued on Sheet 22-2

Tariff C.S.-I.R.P. Continued
(Contract Service – Interruptible Power)

Rate
Credits under this tariff of $3.68/kW/month will be provided for interruptible load that qualifies under PJM's Demand Response Program rules as capacity for the purpose of the Company's Fixed Resource Requirement (FRR) obligation.

Tariff	Tariff Type	Tariff Code Description	Tariff Description
321	IR	CS-IRP SEC	IRP-IGS SECONDARY
330	IR	CS-IRP PR	IRP-IGS PRIMARY
331	IR	CS-IRP ST	IRP-IGS SUBTRANSMISSION
332	IR	CS-IRP TR	IRP-IGS TRANSMISSION

Charges for service under this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect the firm service rates otherwise available to the Customer.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 33
Decommissioning Rider	Sheet No. 34
Securitized Surcharge Rider	Sheet No. 35
Federal Tax Cut Tariff	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

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T

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5.

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Confidentiality
All terms and conditions of any written contract under this Tariff shall be protected from disclosure as confidential, proprietary trade secrets, if either the Customer or the Company requests a Commission determination of confidentiality pursuant to 807 KAR 5:001 Section 7 and the request is granted.

Special Terms and Conditions
Except as otherwise provided in the written agreement, this Tariff is subject to the Company's Terms and Conditions of Service.

Continued on Sheet 22-3

T

Tariff C.S.-I.R.P. Continued
(Contract Service – Interruptible Power)

T

Special Terms and Conditions Continued

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP or by special agreement with the Company. T

Rider D.R.S.
(Demand Response Service)

Availability of Service

Available for Demand Response Service ("DRS") to customers that take firm service from the Company under a standard demand-metered rate schedule and that have the ability to curtail load under the provisions of this Schedule. Each customer electing service under this Schedule shall contract, via a Contract Addendum, for a definite amount of firm and interruptible capacity agreed to by the Company and the customer. The interruptible capacity amount shall not exceed the Customer's average on-peak demand for the past 12 months. The Company reserves the right to limit the aggregate amount of interruptible capacity contracted for under this Schedule. The Company will take Customer DRS requests in the order received. Customers taking service under this Schedule shall not participate in any PJM demand response program for Capacity.

Conditions of Service

1. The Company, in its sole discretion, reserves the right to call for curtailments of the Customer's interruptible load at any time. Such interruptions shall be designated as "Discretionary Interruptions" and shall not exceed sixty (60) hours of interruption during any Interruption Year. The "Interruption Year" shall be defined as the consecutive twelve (12) month period commencing on June 1 and ending on May 31. Should this Schedule become effective on a date other than June 1, the period from the effective date of this Schedule until the next May 31 after such effective date shall be referred to as the "Initial Partial Interruption Year." In any Initial Partial Interruption Year, Discretionary Interruptions shall not exceed a number of hours equal to the product of the number of full calendar months during the Initial Partial Interruption Year and the annual interruption hours divided by 12.

2. The monthly Interruptible Demand Credit Rate shall be $5.50/kW-month, credited to participating Customers' bills for standard tariff service.

3. The Company will endeavor to provide the Customer with as much advance notice as possible of a Discretionary Interruption. The Company shall provide notice at least 90 minutes prior to the commencement of a Discretionary Interruption. Such notice shall include both the start and end time of the Discretionary Interruption. For any Discretionary Interruption, the Customer shall be permitted to choose not to interrupt and to continue to operate during the event, provided that the Customer pays the DRS Event Failure Charge. Discretionary Interruptions shall begin and end on the clock hour.

4. Discretionary Interruption events shall be three (3) consecutive hours and there shall not be more than six (6) hours of Discretionary Interruption per day.

5. The Company will inform the Customer regarding the communication process for notices to curtail. The Customer is ultimately responsible for receiving and acting upon a curtailment notification from the Company.

6. The minimum interruptible capacity contracted for under this Schedule will be 500 kW. Customers with multiple electric service accounts at a single location may aggregate those individual accounts to meet the 500 kW minimum interruptible capacity requirement under this Schedule; however, the interruptible capacity committed for each individual account shall not be less than 100 kW.

7. All Customer meter data required under this Schedule shall be determined from 15- or 30-minute integrated metering, as applicable based on the Customer's rate schedule, with remote interrogation capability and demand recording equipment. Such metering equipment shall be owned, installed, operated, and maintained by the Company.

Continued on Sheet 23-2

Rider D.R.S. Continued
(Demand Response Service)

8. NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS SCHEDULE.

Interruptible Capacity Reservation
The Customer shall have established a total Capacity Reservation under its Contract for Service under the applicable demand-metered rate schedule. In a Contract Addendum, the Customer shall designate a set amount of kW of that total Capacity Reservation as the Firm Service Capacity Reservation, which is not subject to interruption under this Schedule. The Interruptible Capacity Reservation shall be the Customer's average on-peak demand over the past 12 months in excess of the Firm Service Capacity Reservation.

The Interruptible Capacity Reservation is subject to annual review and adjustment by the Company and the Customer.

Monthly Interruptible Demand Credit
The monthly Interruptible Demand Credit shall be equal to the product of Demand Credit per kW-month and the Customer's Interruptible Capacity Reservation kW.

Interruption Event Compliance
A Customer will be determined to have failed a DRS interruption event if the Customer has not achieved at least ninety (90) percent of their agreed upon interruptible capacity reservation during the duration of a DRS event.

DRS Event Failure
A Customer that fails one or more DRS interruption events shall repay a portion of the Customer's total annual DRS Interruptible Demand Credit per the following table:

Number of Failures	Penalty Payment %
Failure 1	5%
Failure 2	10%
Failure 3	10%
Failure 4	15%
Failure 5	15%
Failure 6	20%
Failure 7	25%
Totals	100%

The DRS Event Failure Charge equals the Customer's Interruptible Capacity Reservation kW, times the DRS Interruptible Demand Credit Rate, times 12, times the corresponding DRS Event Failure Charge Penalty Payment % set forth in the table above. Under no circumstance will a Customer be charged for DRS interruption event failures in an amount greater than the annual amount of DRS Interruptible Demand Credits the Customer would have or has received in an Interruption Year.

Settlement
The net amount of the monthly Interruptible Demand Credit and any DRS Event Failure Charge will be included in the Customer's monthly bill for electric service under its demand-metered rate schedule.

Continued on Sheet 23-3

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Rider D.R.S. Continued
(Demand Response Service)

T

Term

A Contract Addendum term under this Schedule shall be at least one (1) Interruption Year and shall continue for each subsequent Interruption Year until either party provides written notice no later than April 2 of its intention to discontinue service effective June 1 under the terms of this Schedule. Any participating Customer must participate for at least one full Interruption Year, therefore a Customer that begins service under this rider during the Initial Partial Interruption Year must then also participate in the subsequent full Interruption Year.

Tariff F.P.
(FlexPay Program)

DN

Availability of Service

This tariff is available on a voluntary basis to all residential customers who have an Advanced Metering Infrastructure (AMI) meter installed at their residence, except as provided below.

This tariff is not available to residential customers taking metered service under Tariff R.S.D. or customers with medical, life threatening, or life support conditions; customers having on-site generation operated in parallel with the Company's system; or customers on the Average Monthly Payment (AMP) plan or Equal Payment Plan (Budget). It also is not available to customers without a valid and operable electronic communication method (i.e., text or electric mail). It also is not available to a customer scheduled for a disconnection of service for nonpayment who has initiated the process for enrollment in this tariff two or more times within a thirty (30) day period without completing all of the requirements for enrollment.

Program Description

Kentucky Power's FlexPay Program is a voluntary payment option that allows customers to prepay for, and pay as they use, electric service.

Terms and Conditions

1. Service under FlexPay will be offered to a customer under the customer's otherwise applicable standard residential rate schedule. Billing will be based on the customer's daily usage, the effective base rate, the tax rate, and all applicable riders and fees. Fixed charges will be applied to the account on a daily basis based on 1/30 of the total fixed charges. These amounts will be subtracted from the customer's daily FlexPay account balance.
2. To enroll in FlexPay, a customer must make an initial payment of $40.00. Any deposit that an existing customer has previously paid to the Company will be applied to the customer's current account balance, with the remaining credit/debit balance transferred to the customer's prepay balance. A customer with an outstanding current balance or final account balance from a previous account may carry-over up to $500 of the account balance to the FlexPay Program. Any payments made to the account will first have a 20% portion of the payment applied to the arrears balance before it is credited to the customer's account until the past due balance is paid.
3. The customer is responsible for monitoring prepaid usage and ensuring that the account balance is sufficient to continue electric service. The customer will be notified when the account reaches the customer-selected balance threshold or the minimum threshold amount of $25.00. Notification will occur through the customer's preferred form of communication, including email, and/or text message. A customer web portal will be available to view the customer's usage information.
4. Should a customer's balance reach zero, the customer will be notified via the customer's chosen communication method. The customer will have until the beginning of the next business day to reestablish a positive balance or the customer's meter will automatically be disconnected during normal business hours. Normal business hours are 8:00 a.m. to 5:00 p.m., Monday through Thursday, and 8:00 a.m. to noon on Fridays, excluding Company-observed holidays and moratoriums. Customers will be required to adjust their payment to cover any accrued balance for usage during weekends, holidays and moratoriums. Once the customer's payment is received and accepted, service will be restored by the Company in a timely manner.

Continued on Sheet 24-2

Tariff F.P.
(FlexPay Program)

DN

Terms and Conditions Continued

5. Financial assistance received for a FlexPay account will be credited to the balance of the FlexPay account upon receipt of the funds.
6. Customers presenting a Winter Hardship Reconnect, Certificate of Need, or Medical Certificate as provided in 807 KAR 5:006, Sections 14, 15, and 16 will be removed from FlexPay and placed on the tariff that is otherwise applicable to the customer's service.
7. No deposit, reconnect, or late fee charges shall apply to customers enrolled in FlexPay.
8. When the Company receives a dishonored negotiable instrument (i.e. returned check), any account credits associated with that instrument will be removed from the customer's account. If the removal of the credits results in the customer's balance reaching zero, the customer will be notified and will have until the beginning of the next business day to reestablish a positive balance or the customer's meter will automatically be disconnected during normal business hours.
9. Actual billing will continue to be based upon the applicable rate and meter readings obtained to determine consumption. FlexPay customers are required to participate in and receive their information through the Company's paperless billing program. Customers will continue to receive an online monthly statement summary containing all of the charges, usage, and payments applied during their normal 30-day billing cycle.
10. Customer accounts must be funded through a Company authorized payment channel, including immediate payment via telephone or website using electronic check, debit or credit cards, and any in-person pay station. Each authorized payment method is subject to Company guidelines. Timing of the payments to the accounts cannot be guaranteed if payment is made through an unauthorized pay agent or by mail.
11. The customer may cancel service under this tariff at any time and will be returned to the applicable traditional post-pay billing option in accordance with Kentucky Power's Commission approved tariffs.
12. Settlement occurs when participation in the plan is terminated. This happens if an account is final billed or if the customer requests termination. If the account finals off-cycle during the billing period, the remaining monthly fixed charges and fees that have not been collected will be applied to the final bill. After settlement of the FlexPay account, any remaining unused balance will be transferred to the customer's other active account(s). If the customer does not have any other active accounts the Company shall refund by one of the following means: a prepaid card, a check, or electric funds transfer (EFT).

Tariff E.D.R.
(Economic Development Rider)

Availability of Service

To encourage economic development in the Company's service territory, limited-term reductions in billing demand charges described herein are offered to qualifying new and existing retail customers who make application for service under this Rider.

Service under this Economic Development Rider (EDR) is intended for specific types of commercial and industrial customers whose operations, by their nature, will promote sustained economic development based on plant and facilities investment and job creation. Availability is limited to customers on a first-come, first-served basis until such time as a total of 250 MW of new load has been added to Kentucky Power's system under the EDR. The EDR is available to commercial and industrial customers served under Tariffs L.G.S. and I.G.S. who meet the following requirements:

(1) A new customer must have at least a monthly maximum billing demand of 500 kW. An existing customer must increase its monthly maximum billing demand by at least 500 kW over the current Base Maximum Billing Demand in order to receive the Incremental Billing Demand Discount (IBDD).

(2) A new customer, or the business expansion by an existing customer, will receive a Supplemental Billing Demand Discount (SBDD) for creating and sustaining at least 25 new permanent full time jobs over the contract term at the service location. The Company reserves the right to verify job counts. Failure to demonstrate the creation of new employment positions or to maintain the employment during the contract term will result in the termination of the supplemental discount.

(3) The customer must demonstrate to the Company's satisfaction that, absent the availability of this EDR, the qualifying new or increased electrical demand would be located outside of the Company's service territory or would not be placed in service.

Terms and Conditions

(1) The Company will offer the EDR to qualifying customers with new or increased load when the Company has sufficient generating capacity available. When sufficient generating capacity is not available, the Company will procure the additional capacity on the customer's behalf. The cost of capacity procured on behalf of the customer shall reduce on a dollar-for-dollar basis the customer's IBDD and SBDD. Such reduction shall be capped so that the customer's maximum demand charge shall be the non- discounted tariff demand charge. The reduction will be applied in reverse chronological order beginning with the most recent customer to receive discounted service under this tariff. The last customer to sign up for the EDR tariff would be the first customer responsible for paying the cost of incremental capacity purchases. In any year during the discount period in which the customer pays the full tariff demand charge for all twelve months, the Company will reduce the term of the contract by one year.

(2) The new or increased load cannot accelerate the Company's plans for additional generating capacity during the period for which the customer receives a demand discount. Customers receiving Temporary Service are not eligible for this EDR.

(3) To receive service under this EDR, the customer shall make written application to the Company with sufficient information contained therein to determine the customer's eligibility for service. At a minimum, such information must include:

Continued on Sheet 25-2

Tariff E.D.R. Continued
(Economic Development Rider)

Terms and Conditions Continued

a. A description and good faith estimate of the new or increased load to be served during each year of the contract,
b. The number of new employees or jobs that will be added as a result of the new load,
c. A description of the anticipated capital investment,
d. A description of all other federal, state or local economic development tax incentives, grants, or any other incentives or assistance associated with the new or expanded project, and
e. A statement that without the EDR discount, the customer would locate elsewhere or would choose not to expand within Kentucky Power's service territory.

(4) For new and existing customers, billing demands for which reductions will be applicable under this EDR shall be for service at a new service location or expanded production at an existing facility and not merely the result of a change of ownership. Relocation of the delivery point of the Company's service, moving existing equipment from another Company-served location or load transfers from another Company-served location do not qualify as a new service location. Relocating existing facilities from within the Company's service territory shall not disqualify the customer from the IBDD as long as the new relocated facility exceeds the Base Maximum Billing Demand of the previous facility by the minimum required amount.

(5) For existing customers, billing demands for which deductions will be applicable under this EDR shall be the result of an increase in business activity and not merely the result of resumption of normal operations following a force majeure, strike, equipment failure, renovation or refurbishment, or other such abnormal operating condition. In the event that such an occurrence has taken place prior to the date of the application by the customer for service under this EDR, the monthly Base Maximum Billing Demand shall be adjusted as appropriate for this analysis to eliminate the effects of such occurrence.

(6) Service under the EDR will be offered under the applicable Tariff L.G.S. or I.G.S. schedule. An EDR will be filed as a Special Contract and must be approved by the Kentucky Public Service Commission before it can be implemented. The total contract period is equal to twice the number of years for which the customer receives a demand discount. The special contract term will be for two (2), four (4) six (6), eight (8), or ten (10) years only.

(7) The IBDD and the SBDD, if applicable, begin when the customer's new or expanded operations are billed for service under this Rider. Temporary jobs created during the construction of new facilities or the expansion phase of existing operations are not eligible to be counted as permanent jobs for the purposes of this EDR.

(8) If construction of new or expanded local distribution and/or transmission related facilities by the Company is required in order to provide the additional service, the customer may be required to make a contribution-in-aid of construction (CIAC) for the installed cost of such facilities pursuant to the provisions of the Company's Terms and Conditions of Service. The total cost of the CIAC, including gross-up by the effect of applicable taxes, will be recovered over the life of the EDR contract period, with no less than 80% recovered during the period for which the customer receives a demand discount. If the customer breaches the terms of the contract or ends the contract prematurely, any unpaid contribution-in-aid of construction must be paid to the Company, and any EDR discounts provided to the customer must be repaid to the Company. CIAC payment provided under this Rider supersedes other payment provisions only in the Company's Terms and Conditions Sheet 2-5 Section 9.

Continued on Sheet 25-3

Tariff E.D.R. Continued
(Economic Development Rider)

(9) The L.G.S., and I.G.S. tariffs each contain a monthly minimum billing demand charge provision. The minimum demand charge provision is waived for EDR customers for up to 36 months depending upon the length of the contract. The provision is waived for the first 36 months of a 10 year contract, the first 24 months of an 8 year contract and the first 12 months of a 6 year contract. If during the special contract discount period, the customer's monthly demand falls below the minimum billing demand level for four (4) consecutive months or six (6) months total in a contract year, then the EDR discount will not be applied and the appropriate tariff minimum billing demand charge provision will be in force until the customer achieves the minimum billing demand level. Applicable EDR discounts will be applied to the qualifying incremental maximum billing demand only and will appear as a separate line item on the customer's bill.

Determination of Monthly Qualifying Incremental Billing Demand
For the purposes of this Rider, the monthly qualifying incremental billing demand will be calculated in the following manner:

Where the new qualifying incremental demand resides in new facilities (or separate facilities for existing customers), those facilities may be metered on a separate meter according to Tariffs L.G.S., I.G.S., for the current billing period and the incremental billing demand will be calculated based upon that facility's meter readings.

Where the new qualifying incremental demand resides in a customer's existing facility with sufficient service and metering capability to accommodate the business expansion, the qualifying incremental billing demand is equal to demand in excess of the Base Maximum Billing Demand. The Base Maximum Billing Demand for each billing month will be calculated by the Company as the average of the previous three years, corresponding month maximum billing demands, subject to Terms and Conditions Items (3) and (4), and will be agreed to by the customer in advance.

Determination of Incremental Billing Demand Discount
Customers meeting all Availability of Service and Terms and Conditions above may contract for service for a period of up to ten (10) years, with a commensurate discount period of up to five (5) years. The qualifying incremental billing demand charge shall be reduced by 50%, 40%, 30%, 20%, 10% in the order of the Customer's choosing at the time of the contract filing. A sample illustration of an (IBDD) for a ten (10) year contract follows:

(a) For the twelve consecutive monthly billings of the first contract year, the qualifying incremental billing demand charge shall be reduced by 50% from the applicable tariff L.G.S. or I.G.S., demand charge;

(b) For the twelve consecutive monthly billings of the second contract year, the qualifying incremental billing demand charge shall be reduced by 40% from the applicable tariff L.G.S. or I.G.S., demand charge;

(c) For the twelve consecutive monthly billings of the third contract year, the qualifying incremental billing demand charge shall be reduced by 30% from the applicable tariff L.G.S. or I.G.S., demand charge;

(d) For the twelve consecutive monthly billings of the fourth contract year, the qualifying incremental billing demand charge shall be reduced by 20% from the applicable tariff L.G.S. or I.G.S., demand charge, but shall not be less than the applicable tariff rate schedule minimum billing demand;

(e) For the twelve consecutive monthly billings of the fifth contract year, the qualifying incremental billing demand charge shall be reduced by 10% from the applicable tariff L.G.S. or I.G.S., demand charge, but shall not be less than the applicable tariff rate schedule minimum billing demand; and

Continued on Sheet 25-4

Tariff E.D.R. Continued
(Economic Development Rider)

(f) All subsequent monthly billings shall be at the full charges stated in the applicable tariff rate schedule for contract years six (6) through ten (10).

The starting point for the IBDD is dependent upon the length of contract: i.e., an eight (8) year contract will have four (4) years of discount and a maximum annual IBDD of 40% in one year. Similarly, a six (6) year contract will have three (3) years of discount and a maximum annual IBDD of 30% in one year.

Determination of Supplemental Billing Demand Discount

At the Company's discretion, a (SBDD) which is applicable to the monthly incremental billing demand charge is available to customers meeting all Availability of Service and Terms and Conditions above, and that create at least twenty five (25) new permanent job opportunities in the facility and that maintain those job opportunities in each discount year. The amount of additional discount is determined by the actual number of jobs maintained in each year. The order in which the SBDD is applied will follow the same order selected by the Customer for the IBDD contract. A sample illustration of the SBDD for a ten (10) year contract follows:

(a) For the twelve consecutive monthly billings of the first contract year, the qualifying incremental billing demand charge shall be reduced an additional 5% for an increase of at least 50 jobs or 2.5% for an increase of at least 25 jobs;

(b) For the twelve consecutive monthly billings of the second contract year, the qualifying incremental billing demand charge shall be reduced an additional 4.5% for an increase of at least 50 jobs or 2.0% for an increase of at least 25 jobs;

(c) For the twelve consecutive monthly billings of the third contract year, the qualifying incremental billing demand charge shall be reduced an additional 4% for an increase of at least 50 jobs or 1. 5% for an increase of at least 25 jobs;

(d) For the twelve consecutive monthly billings of the fourth contract year, the qualifying incremental billing demand charge shall be reduced an additional 3.5% for an increase of at least 50 jobs or 1. 0% for an increase of at least 25 jobs;

(e) For the twelve consecutive monthly billings of the fifth contract year, the qualifying incremental billing demand charge shall be reduced an additional 3% for an increase of at least 50 jobs or 0.5% for an increase of at least 25 jobs; and

(f) All subsequent monthly billings shall be at the full charges stated in the applicable tariff rate schedule for contract years six (6) through ten (10)

The length of the SBDD shall be identical to the length of the IBDD. The starting point for the discount will be commensurate with the contract length, i.e., an eight (8) year contract will have four (4) years of discount with a maximum SBDD of either 4.5% or 2.0% as appropriate during one year of the contract.

The appropriate discount(s) shall be applicable over a period of up to 60 consecutive billing months as selected by the Customer in 12-month increments at the time of the contract.

Continued on Sheet 25-5

Tariff E.D.R. Continued
(Economic Development Rider)

Terms of Contract

A contract or agreement addendum for service under this Rider, in addition to service under Tariffs L.G.S. or I.G.S., shall be executed by the Customer and the Company for the time period which includes the start-up period and the multi-year period during which a Total Demand Charge discount is in effect and an equal multi-year period during which the customer agrees to pay the full rates in the applicable Tariff rate schedule.

At a minimum, the contract or agreement addendum shall specify the Base Maximum Billing Demand, the anticipated annual total qualifying demand, the Adjustment Factor and related provisions to be applicable under this Rider, and the effective date for the contract addendum.

The customer may discontinue service under this Rider before the end of the contract or agreement addendum only by reimbursing the Company for any and all demand reductions received under this Rider when billed at the applicable tariff schedule rate. In order to secure repayment of demand reductions received under this Rider, all customers whose contracts have an initial start date of January 16, 2024 and after will be required to post appropriate security (cash, surety bond, letter of credit, or other form of security acceptable to the Company) in an amount up to the total demand reductions received and estimated to be received under the contract or agreement addendum, and upon any additional terms as established in the contract or agreement addendum.

Special Terms and Conditions

Except as otherwise provided in this Rider, written agreements shall remain subject to all of the provisions of the applicable tariffs. This Rider is subject to the Company's Terms and Conditions of Service.

Tariff R.E.A.
(Residential Energy Assistance)

Proceeds of the charge and a Company contribution (that equals two times the amount collected from the per meter charge) will be used to provide financial assistance to eligible residential customers' electric bills during peak heating months (January through April).

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D.2

Rate
$0.40 per month per residential account.

Programs
Participation in the programs below will be determined by the residential customer's local community action agency in accordance with guidelines approved by the Commission and the availability of funds. Customer participation is limited to one program each calendar year.

Home Energy Assistance in Reduced Temperatures (HEART)
Participating low-income residential customers, whose primary source of heat is electric, are eligible to receive an electric bill credit of $115.00 a month for bills rendered in January through April.

Participating low-income residential customers, whose primary source of heat is non-electric, are eligible to receive an electric bill credit of $58.00 a month for bills rendered in January through April.

Temporary Heating Assistance in Winter (THAW)
Participating residential customers, who are experiencing temporary economic hardships, are eligible to receive electric bill credits totaling no more than $175.00 for bills rendered in January through April in any single calendar year.

Tariff K.E.D.S.
(Kentucky Economic Development Surcharge)

Proceeds of the surcharge and matching Company contributions will be used to fund economic development programs and activities as determined by the Company within the 20 counties comprising Kentucky Power's certified territory.

Applicable
To Tariffs G.S, S.G.S. – T.O.D., M.G.S. – T.O.D., L.G.S., L.G.S. – T.O.D., I.G.S., C.S. – I.R.P., M.W.

Rate
$1.00 per month per commercial account.

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Tariff D.S.M.C.
(Demand-Side Management Adjustment Clause)

Applicable

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., and M.W.

Rate

1. The Demand-Side Management (DSM) clause shall provide for periodic adjustment per KWH of sales equal to the DSM costs per KWH by customer sector according to the following formula:

$$\text{(c) Adjustment Factor} = \frac{\text{DSM}}{\text{S(c)}}$$

Where DSM is the cost by customer sector of demand-side management programs, net lost revenues, incentives, and any over/under recovery balances; (c) is customer sector; and S is the adjusted KWH sales by customer sector.

2. Demand-Side Management (DSM) costs shall be the most recent forecasted cost plus any over/under recovery balances recorded at the end of the previous period.

   a. Program costs are any costs the Company incurred associated with demand-side management which were approved by the Kentucky Power Company DSM Collaborative. Examples of costs to be included are contract services, allowances, promotion, expenses, evaluation, lease expense, etc. by customer sector.

   b. Net lost revenues are the calculated net lost revenues by customer sector resulting from the implementation of the DSM programs.

   c. Incentives are a shared-savings incentive plan consisting of one of the following elements: The efficiency incentive, which is defined as 15 percent of the estimated net savings associated with the programs. Estimated net savings are calculated based on the California Standard Practice Manual's definition of the Total Resources Cost (TRC) test, or the maximizing incentive which is defined as 5 percent of actual program expenditures if program savings cannot be measured.

   d. Over/ Under recovery balances are the total of the differences between the following:

      i. the actual program costs incurred versus the program costs recovered through DSM adjustment clause, and

      ii. the calculated net lost revenues realized versus the net lost revenues recovered through the DSM adjustment clause, and

      iii. the calculated incentive to be recovered versus the incentive recovered through the DSM adjustment clause.

3. Sales (S) shall be the total ultimate KWH sales by customer sector less non-metered, opt-out and lost revenue impact KWHs by customer sector.

Continued on Sheet 28-2

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Rate Continued

4. The provisions of the Demand-Side Management Adjustment Clause will be effective for the period ending December 31, 2025.

5. The DSM adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

6. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

7. The resulting range for each customer sector per KWH during the three-year Experimental Demand-Side Management Plan is as follows:

	Customer Sector		
	Residential	Commercial	Industrial*
DSM(c)	$1,107,281	$817,419	0
S(c)	1,887,324,885	1,425,512,271	0
Adjustment Factor	$0.000587	$0.000573	0

* The Industrial Sector has been discontinued pursuant to the Commission's Order dated September 28, 1999.

Program Descriptions

The D.S.M.C. program availability, program, rate, and equipment descriptions follow:

Continued on Sheet 28-3

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Program: TEE – Targeted Energy Efficiency

Availability of Service

Available on a voluntary basis until funds are depleted to individual residential customers receiving retail electric service from the Company, who have primary electric heat and use an average of 700 kWh per month. Residential customers without primary electric heating may also be eligible for limited efficiency measures if they have electric water heating and use an average of 700 kWh per month from November through March. To qualify, the household's income cannot exceed the designated poverty guidelines as administered by the local community action agency.

Program Description

The Targeted Energy Efficiency (TEE) Program provides weatherization and energy efficiency services to qualifying residential customers who need help reducing their energy bills. The Company provides funding for this program through the Kentucky Community Action network of not-for-profit community action agencies.

Two different supplemental assistance funds are available under the Company's TEE Program:

- **The Weatherization Assistance Program:** Kentucky Power's Weatherization Assistance Program is designed to provide supplemental funding to the Department of Energy's Weatherization Assistance Program operated by the Kentucky Community Action network of not-for-profit community action agencies. Funds from this program provide energy saving improvements to an existing home. Program services include residential energy audits, the installation of home weatherization/energy conservation items and customer education on home energy efficiency. The home weatherization/energy conservation measures available under this program may include, but are not limited to:

    - High efficiency lighting
    - Domestic hot water pipe insulation
    - Water heater insulation wrap (electric domestic hot water only)
    - Low flow showerhead
    - Low flow faucet aerator
    - Air and duct sealing (electric heat only)
    - Insulation (electric heat only)
    - Efficient windows and doors
    - Air source heat pump
    - Heat pump water heaters
    - Ductless heat pumps
    - ENERGY STAR room air conditioners

Continued on Sheet 28-4

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Program: TEE – Targeted Energy Efficiency Continued

Program Description Continued T

- **The Weatherization Readiness Fund:** Kentucky Power's Weatherization Readiness Fund is designed to provide supplemental funding to the Department of Energy's Weatherization Readiness Fund operated by the Kentucky Community Action network of not-for-profit community action agencies. The Weatherization Readiness Fund is intended to provide funding to make homes ready and eligible to then receive funds under the Weatherization Assistance Program. This program provides funds for community action agencies to address a homes' health, safety and structural issues that otherwise would prohibit participation in the Weatherization Assistance Program. The Company provides funding for this program through the Kentucky Community Action network of not-for-profit community action agencies. Participants under this program are eligible to receive from Kentucky Power up to $1,000 per home in supplemental funding.

Rate
No rate applies for this program.

Equipment
The Kentucky Community Action network of not-for-profit community action agencies will furnish and install, in the customer's presence, the equipment or improvements as provided by this program.

Continued on Sheet 28-5

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Program: HEIP – Home Energy Improvement Pilot Program

Availability of Service
Available on a voluntary basis until funds are depleted to individual residential customers living in single family, multi-family, or mobile homes, receiving retail electric service from the Company, and who have an electric heating, ventilation, and air conditioning (HVAC) system. "Multi-family" includes any residential unit that is not considered single family (for example, apartment, condominium, townhouse, etc.).

The Home Energy Improvement Program will be a three-year pilot ending February 27, 2028.

Program Description

- **Home Energy Audits.** The customer receives, at no additional cost to that customer, an in-home energy audit and installation of certain energy conservation measures. An energy auditor performs an in-home energy audit, identifying key areas of the home that are wasting energy and provides recommendations to make the home more energy efficient. Participants are then eligible to receive installation of select energy conservation measures recommended by the energy auditor. Eligible measures may include but are not limited to:
    - Domestic hot water pipe insulation (only customers with electric domestic hot water)
    - Water heater insulation wrap (only customers with electric domestic hot water)
    - Low-flow showerhead (only customers with electric domestic hot water)
    - Low-flow faucet aerator (only customers with electric domestic hot water)
    - Weatherstripping / caulking of doors and windows / door sweep
- **HVAC Equipment.** Customers are eligible to receive incentives, or rebates, for qualifying HVAC equipment installed by a participating dealer. Qualifying measures include ductless heat pumps and air conditioners, air-source heat pumps, central air conditioners, heat pump water heaters, ENERGY STAR room air conditioners, and smart thermostats.
- **Weatherization Measures.** Customers are eligible to receive incentives, or rebates, for qualifying weatherization measures installed by a participating dealer. Qualifying measures include attic insulation, floor insulation above crawlspace, air sealing, and duct sealing and insulation.

Incentives/Rebates
Rebates will vary depending on the efficiency rate of the measures installed. Measures may be modified by Kentucky Power's implementation contractor and Kentucky Power to reflect market conditions.

Rebates are issued to qualifying customers upon completion of the project and submission of the program application to Kentucky Power.

A complete list of the eligible equipment and incentive/rebate amounts can be found in the Program Application accessible online at KentuckyPower.com/savings/home/energy, or by contacting Kentucky Power Customer Service at 800-572-1113.

Continued on Sheet 28-6

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Program: HEIP – Home Energy Improvement Pilot Program Continued

Equipment

Home Energy Audits: The Company, or its authorized agents, will furnish and install, in the customer's presence, the energy conservation measures as recommended by the energy auditor after the in-home energy audit.

HVAC Equipment and Weatherization Measures: The customer must meet the program requirements, and it is the customer's responsibility to purchase and install the HVAC equipment and weatherization measures. Those measures must be installed by a qualified participating dealer. A complete list of qualifying participating dealers can be accessed online at KentuckyPower.com/savings/home/energy or by contacting Kentucky Power Customer Service at 800-572-1113.

Agreement

A customer program application agreement is required to participate in this program.

Rate

No rate applies for this program**.**

Continued on Sheet 28-7

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Program: CESP – Commercial Energy Solutions Pilot Program

Availability of Service
Available on a voluntary basis until funds are depleted to commercial (non-industrial and non-residential) customers in Kentucky Power's service territory.

The Commercial Energy Solutions Program will be a three-year pilot ending February 27, 2028.

Program Description

The Commercial Energy Solutions Program offers commercial customers a convenient way to receive funding for common energy efficiency measures purchased and installed at the cost of the customer. The Company will provide an energy audit at no additional cost to the customer. An inspector will perform a walk-through, identifying key areas that are wasting energy and will provide recommendations to make the building more energy efficient. Financial incentives, or rebates, will be made available to those commercial customers who implement qualified energy-efficient improvements and technologies.

Incentives, or rebates, are available for a variety of energy-saving measures in existing buildings. Qualifying customers may elect to receive incentives/rebates for eligible energy efficiency measures from a pre-qualified list provided by Kentucky Power. Incentives for custom measures will not be offered at this time. Eligible energy efficiency measures include the following:

- **Energy Efficient Lighting.** Proven qualifying technologies for which incentives, or rebates, will be provided under this program include LED lighting, daylighting controls, and occupancy sensors.

A complete list of the eligible equipment and incentive, or rebate, amounts can be found in the Program Application accessible online at KentuckyPower.com/savings/business, or by contacting Kentucky Power Customer Service at 888-710-4237.

Incentives/Rebates
The total maximum rebate amount available to qualifying commercial customers is $25,000 annually per customer account. Kentucky Power may revise incentive amounts and or the maximum incentive per customer account based upon program implementation contractor recommendations and/or overall customer response to the program.

Rebates are issued to qualifying customers upon completion of the project and submission of the program application to Kentucky Power.

Equipment
The Company, or its authorized agents, may provide support for the installation of qualifying energy-saving measures by approved program contractors. The Company, or its authorized agents, will evaluate the customer's installed energy measures for eligibility under this program. The Company, at its discretion, will determine whether the customer's installed energy-saving measures qualify for incentives/rebates under this program.

Continued on Sheet 28-8

T

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

T

Program: CESP – Commercial Energy Solutions Pilot Program Continued

Agreement
A customer program application agreement is required to participate in this program.

Rate
No rate applies for this program.

Tariff S.S.C.
(System Sales Clause)

Applicable

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L. and S.L.

Rate

1. When the annual net revenues from system sales are above or below the annual base net revenues from system sales, as provided in paragraph 2 below, an additional credit or charge equal to the product of the KWHs and a system sales adjustment factor (A) shall be made, where "A", calculated to the nearest 0.0001 mill per kilowatt-hour, is defined as set forth below.

   Annual System Sales Adjustment Factor (A) = (1.0 [Ta –Tb+U/a])/Sa

   In the above formula "T" is Kentucky Power Company's (KPCo) annual net revenues from system sales in the current annual (a), base (b) periods, and "S" is the KWH sales in the current annual (a) period, all defined below. "U/a" represents any under-or-over recovery from the prior period.

   The applicable rate for service rendered on and after September 27, 2024, calculated in accordance with the above formula, is $0.00058 per kWh.

2. The net revenue from KPCo's sales to non-associated companies as reported in the FERC Energy Regulatory Commission's Uniform System of Accounts under Account 447, Sales for Resale, shall consist of and be derived as follows:

   a. KPCo's total revenues from system sales as recorded in Account 447, less b. and c. below.

   b. KPCo's total out-of-pocket costs incurred in supplying the power and energy for the sales in a. above.

      The out-of-pocket costs include all operating, maintenance, tax, transmission losses and other expenses that would not have been incurred if the power and energy had not been supplied for such sales, including demand and energy charges for power and energy supplied by Third Parties.

   c. KPCo's environmental costs allocated to non-associated utilities in the Company's Environmental Surcharge Report.

3. The base annual net revenues from system sales are: $4,425,300. I

4. Sales (S) shall be equated to the sum of (a) generation (including energy produced by generating plant during the construction period), (b) purchase, and (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) inter-system sales and less (f) total system losses.

5. The system sales adjustment factor shall be based upon actual annual revenues and costs for system sales, subject to subsequent adjustment upon final determination of actual revenues and costs.

Continued on Sheet 29-2 T

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Tariff S.S.C. Continued
(System Sales Clause)

T

6. The annual System Sales Clause shall be filed with the Commission no later than August 15th of each year before it is scheduled to go into effect on Cycle 1 of the October billing cycle. The Company shall update the Annual System Sales Adjustment Factor for the period ending June 30, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

Tariff F.A.C.
(Fuel Adjustment Clause)

Applicable

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D. 2, R.S.D., G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L.

Rate

1. The fuel clause shall provide for periodic adjustment per kWh of sales equal to the difference between the fuel costs per kWh of sales in the base period and in the current period according to the following formula:

$$\text{Adjustment Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

Where F is the expense of fossil fuel in the base (b) and current (m) periods; and S is sales in the base (b) and current (m) periods, all as defined below:

2. F(b)/S(b) shall be so determined that on the effective date of the Commission's approval of the utility's application of the formula, the resultant adjustment will be equal to zero (0).

3. Fuel costs (F) shall be the most recent actual monthly cost of:

   a. Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of the fuel related substitute generation, plus

   b. The actual identifiable fossil and nuclear fuel costs [if not known--the month used to calculate fuel (F), shall be deemed to be the same as the actual unit cost of the Company generation in the month said calculations are made. When actual costs become known, the difference, if any, between fuel costs (F) as calculated using such actual unit costs and the fuel costs (F) used in that month shall be accounted for in the current month's calculation of fuel costs (F)] associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute the forced outages, plus

   c. The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases, the charges as a result of scheduled outage, and other charges for energy being purchased by the Company to substitute for its own higher cost of energy; and less

   d. The cost of fossil fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

Continued on Sheet 30-2

Tariff F.A.C. Continued
(Fuel Adjustment Clause)

Rate Continued

e. The fuel-related costs charged to the Company by PJM Interconnection LLC those costs identified in the following Billing Line Items, as may be amended from time to time by PJM Interconnection LLC: Billing Line Items 1210, 2210, 1215, 1218, 2217, 2218, 1230, 1250, 1260, 2260, 1370, 2370, 1375, 2375, 1400, 1410, 1420, 1430, 1478, 1340, 2340, 1460, 1350, 2350, 1360, 2360, 1470, 1377, 2377, 1480, 1378, 2378, 1490, 1500, 2420, 2220, 1200, 1205, 1220, 1225, 2500, 2510, 1930, 2211, 2215, 2415 and 2930.

f. All fuel costs shall be based on weighted average inventory costing.

4. Forced outages are all nonscheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the Commission, include the fuel costs of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel costs (F) in subsection (3)(a) and (b) above, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation.

5. Sales (S) shall be all kWh's sold, excluding intersystem sales. If, for any reason billed system sales cannot be coordinated with the fuel costs for the billing period, sales may be equated to: (i) generation, plus (ii) purchases, plus (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) intersystem sales referred to in subsection (3)(d) above, less (vi) total system losses. Utility used energy shall not be excluded in the determination of sales (S).

6. The cost of fossil fuel shall only include the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts for Public Utilities and Licensees, less any cash or other discounts.

7. At the time the fuel clause is initially filed, the utility shall submit copies of each fossil fuel purchase contract not otherwise on file with the Commission and all other agreements, options, amendments, modifications, and similar documents related to the procurement of fuel supply or purchased power. Any changes in the contracts or other documents, including price escalations, and any new agreements entered into after the initial submission, shall be submitted at the time they are entered into. If fuel is purchased from utility-owned or controlled sources, or the contract contains a price escalation clause, those facts shall be noted and the utility shall explain and justify them in writing. Fuel charges, which are unreasonable, shall be disallowed and may result in the suspension of the fuel adjustment clause based on the severity of the utility's unreasonable fuel charges and any history of unreasonable fuel charges. The Commission on its own motion may investigate any aspect of fuel purchasing activities covered by 807 KAR 5:056 (Fuel Adjustment Clause).

8. The monthly fuel adjustment shall be filed with the Commission no later than ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment.

9. Copies of all documents required to be filed with the Commission under 807 KAR 5:056 shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

Continued on Sheet 30-3

Tariff F.A.C. Continued
(Fuel Adjustment Clause)

10. At six (6) month intervals, the Commission shall conduct a formal review and may conduct public hearings on a utility's past fuel adjustments. The Commission shall order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustments the Commission finds unjustified due to improper calculation or application of the charge or improper fuel procurement practice.

11. Every two (2) years following the initial effective date of each utility's fuel clause, the Commission shall conduct a formal review and evaluate past operations of the clause, disallow improper expenses, and to the extent appropriate, reestablish the fuel clause charge in accordance with Section 1 (2) of 807 KAR 5:056.

12. The Commission may conduct a public hearing if the Commission finds that a hearing is necessary for the protection of a substantial interest or is in the public interest. T

13. Resulting cost per kilowatt-hour in January 2022 to be used as the base cost in Standard Fuel Adjustment Clause is: T

Fuel	January 2022	÷	$19,529,185	=	$0.03380/kWh
Sales	January 2022		577,776,513		

This, as used in the Fuel Adjustment Clause, is 3.380¢ per kilowatt-hour.

Transitional Monthly Credit

1. Consistent with the Settlement Agreement dated November 14, 2024, and approved by the Commission by its order dated December 13, 2024 in Case No. 2023-00008, Kentucky Power will provide to customers a transitional monthly credit to reduce the amount of future fuel costs recovered from Kentucky retail customers through this tariff as a fair and reasonable compromise of that proceeding. The credit is subject to all conditions precedent and other provisions in the Settlement Agreement. T

2. The Company shall include an annual reconciliation of the transitional monthly credit as part of the over or under-recovery computation in the Company's Fuel Adjustment Clause filed in May 2025 and May 2026, respectively. T

3. The applicable rates on a kWh basis are calculated as follows and will be applied to customers' January through April bills for 2025 and 2026: T

	Residential ($/kWh)	All Other ($/kWh)
Transitional Credit Amount	$6,710,990	$9,825,827
Historic January through April Retail kWh	1,379,035,920	2,272,033,096
Rate	(0.00487)	(0.00432)

4. The applicable rates to be applied to customers' January through April bills for 2026 are subject to the Commission's issuance of a final order approving without modification the settlement agreement to be filed in the 2-year review proceeding concerning the 2022-2024 FAC Review Period. T

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Tariff P.P.A.
(Purchase Power Adjustment)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S. – I.R.P., M.W., O.L. and S.L.

Rate
The annual purchase power adjustment factor will be computed using the following formula:

1. Annual Purchase Power Net Costs (PPANC)

PPANC = N+CSIRP +RP+GS-BPP DT

Where:

BPP = The annual amount of purchase power costs included in base rates, $7,988,625. I

a. N = The annual cost of power purchased by the Company through new Purchase Power Agreements and purchased power expense from avoided cost payments to net metering customers under tariff N.M.S.II above or below the $3,309,439 included in BPP. All new purchase power agreements shall be approved by the Commission to the extent required by KRS 278.300. I
b. CSIRP = The net annual cost of any credits provided to customers under Tariff C.S.-I.R.P., Tariff D.R.S., and special contracts for interruptible service above or below the $2,616,539 included in BPP. D I
c. RP = The cost of fuel related to substitute generation less the cost of fuel which would have been used in plants suffering forced generation or transmission outages above or below the $190,571 included in BPP. D R
d. GS = Net gains or losses on incidental sales of gas above or below the $1,872,076 included in BPP. TI

Continued on Sheet 31-2

Tariff P.P.A. Continued
(Purchase Power Adjustment)

Rates

Tariff Class	$/kWh	$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.	$0.00226	--
S.G.S.-T.O.D.	$0.00195	--
M.G.S.-T.O.D.	$0.00195	--
G.S.	$0.00195	--
L.G.S., L.G.S.-T.O.D.	$0.00075	$0.34
L.G.S.-L.M.-T.O.D.	$0.00181	--
I.G.S. and C.S.-I.R.P.	$0.00075	$0.46
M.W.	$0.00156	--
O.L.	$0.000110	--
S.L.	$0.000111	--

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS, LGS-T.O.D, IGS, and CS-I.R.P. tariff classes.

The Purchase Power Adjustment factors shall be modified annually using the following formula:

D

For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total}) + PPA(D) \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{PPA(D) \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

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Tariff P.P.A. Continued
(Purchase Power Adjustment)

Rates Continued

Where:

1. "PPA(D)" is the actual annual retail PPA demand-related costs, plus any prior review period (over)/under recovery.

2. "PPA(E) is the actual annual retail PPA energy-related costs, plus any prior review period (over)/under recovery.

3. "BE_{Class}" is the forecasted annual retail jurisdictional billing kWh for each tariff class for the current year. T

4. "BD_{Class}" is the forecasted annual retail jurisdictional billing kW for each applicable tariff class for the current year.

5. "CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.		0.022274%	
S.G.S.-T.O.D.		0.017461%	
M.G.S.-T.O.D.		0.017461%	
G.S.		0.017461%	
L.G.S., L.G.S.-T.O.D.		0.015157%	
L.G.S.-L.M.-T.O.D.		0.015157%	
I.G.S. and C.S.-I.R.P.		0.011787%	
M.W.		0.011468%	
O.L.		0.003614%	
S.L.		0.003595%	

R

6. "BE_{Total}" is the sum of the BE Class for all tariff classes.

7. "CP_{Total}" is the sum of the CP Class for all tariff classes.

8. The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.28% and the KPSC Maintenance Fee of 0.1595% and other similar revenue based taxes or assessments occasioned by the Purchase Power Adjustment Rider revenues. R I

9. The annual PPA factors shall be filed with the Commission by August 15 of each year, with rates to begin with the October billing period, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

   Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

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Tariff G.R.
(Generation Rider)

N

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S. – I.R.P., M.W., O.L. and S.L.

Rate
The annual Generation Rider factor will be computed using the following formula:

Non-Environmental Mitchell Annual Revenue Requirement (ARR) = (RB+CWIP)(ROR)+DE+PT+OU

Where:

RB = Non-Environmental Rate Base for Mitchell represented by the sum of plant in service less accumulated depreciation;

CWIP = Construction Work in Progress for Non-Environmental Mitchell Projects;

ROR = Rate of Return on Non-Environmental Mitchell Rate Base;

DE = Depreciation Expense;

PT = Property Taxes;

OU = Cumulative difference between revenues received and actual costs for the reporting period, representing the (over) or under recovery.

Rates

Tariff Class	$/kWh	$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.	$0.00519	--
S.G.S.-T.O.D.	$0.00406	--
M.G.S.-T.O.D.	$0.00406	--
G.S.	$0.00406	--
L.G.S., L.G.S.-T.O.D.	--	$1.15
L.G.S.-L.M.-T.O.D.	$0.00352	--
I.G.S. and C.S.-I.R.P.	--	$1.63
M.W.	$0.00267	--
O.L.	$0.00084	--
S.L.	$0.00084	--

I

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS, LGS-T.O.D, IGS, and CS-I.R.P. tariff classes.

Continued on Sheet 32-2

Tariff G.R. Continued
(Generation Rider)

N

The Generation Rider factors shall be modified annually using the following formula:

For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{GR(E) \times (BE_{Class} / BE_{Total}) + GR(D) \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{GR(E) \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{GR(D) \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

Where:

1. "GR(D)" is the actual annual retail GR demand-related costs.
2. "GR(E) is the actual annual retail GR energy-related costs.
3. "BE_{Class}" is the forecasted annual retail jurisdictional billing kWh for each tariff class for the current year.
4. "BD_{Class}" is the forecasted annual retail jurisdictional billing kW for each applicable tariff class for the current year.
5. "CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:

Continued on Sheet 32-3

N

Tariff G.R. Continued
(Generation Rider)

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.		0.022274%	
S.G.S.-T.O.D.		0.017461%	
M.G.S.-T.O.D.		0.017461%	
G.S.		0.017461%	
L.G.S., L.G.S.-T.O.D.		0.015157%	
L.G.S.-L.M.-T.O.D.		0.015157%	
I.G.S. and C.S.-I.R.P.		0.011787%	
M.W.		0.011468%	
O.L.		0.003614%	
S.L.		0.003595%	

6. "BE_{Total}" is the sum of the BE Class for all tariff classes.

7. "CP_{Total}" is the sum of the CP Class for all tariff classes.

8. The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.28% and the KPSC Maintenance Fee of 0.1595% and other similar revenue based taxes or assessments occasioned by the Generation Rider revenues.

9. The annual GR factors shall be filed with the Commission by February 15 of each year based on prior calendar year, with rates to begin with the April billing period, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

10. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

D

Tariff E.S.
(Environmental Surcharge)

Applicable

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L.

Rate

The environmental surcharge shall provide for monthly adjustments based on a percent of revenues, equal to the difference between the environmental compliance costs in the base period as provided in Paragraph 2 below and in the current period as provided in Paragraph 3 below.

The retail share of the revenue requirement will be allocated between residential and non-residential retail customers based upon their respective total revenues during the previous calendar year. The Environmental Surcharge will be implemented as a percentage of total revenues for the residential class and as a percentage of non-fuel revenues for all other customers.

The revenues to which the residential Environmental Surcharge factor are applied is the sum of the customer's Service Charge, Energy Charge(s), Demand Charge (if applicable), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Residential Energy Assistance, Purchase Power Adjustment, and Generation Rider. T

The revenues to which the all other customer Environmental Surcharge factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Kentucky Economic Development Surcharge, Purchase Power Adjustment, and Generation Rider. T

1. Monthly Environmental Surcharge Gross Revenue Requirement, E(m)

Where:	E(m)	=	CRR-BRR
	CRR	=	Current Period Revenue Requirement for the Expense Month.
	BRR	=	Base Period Revenue Requirement.

2. Base Period Revenue Requirement, BRR

BRR = The Following Monthly Amounts:

Billing Month		Base Net Environmental Costs
January	$	3,431,790
February		3,493,649
March		3,165,974
April		3,567,100
May		3,262,891
June		2,825,006
July		2,815,870
August		2,808,114
September		2,667,203
October		3,372,548
November		3,258,712
December	$	3,306,420
	$	37,975,278

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Tariff E.S. Continued
(Environmental Surcharge)

In accordance with the Stipulation and Settlement Agreement approved by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, the Mitchell FGD and all related associated costs are not included in base rates or the Base Revenue Requirement but will be included in the Current Period Revenue Requirement. The Mitchell FGD will be excluded from Base Rates at least until June 30, 2020.

3. Current Period Revenue Requirement, CRR

$$CRR=[((RB_{KP(c)})(ROR_{KP(c)})/12) + OE_{KP(c)} - AS]$$

Where:

$RB_{KP(c)}$	=	Environmental Compliance Rate Base for Mitchell.
$ROR_{KP(c)}$	=	Annual Rate of Return on Mitchell Environmental Compliance Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.
$OE_{KP(c)}$	=	Monthly Pollution Control Operating Expenses for Mitchell.
AS	=	Net proceeds from the sale of Title IV and CSAPR SO 2 emission allowances, ERCs, and NOx emission allowances, reflected in the month of receipt.

"KP(C)" identifies components from Mitchell Units – Current Period.

The Environmental Compliance Rate Base for Kentucky Power reflects the current cost associated with the 1997 Plan, the 2003 Plan, the 2005 Plan, the 2007 Plan, the 2015 Plan, the 2017 Plan, the 2019 Plan, and the 2021 Plan. The Environmental Compliance Rate Base for Kentucky Power should also include construction work in progress until assets are placed in service and cash working capital allowance based on the net operations and maintenance expense lead days of 19.82 authorized in Case No. 2025-00257. The Operating Expenses for Kentucky Power reflects the current operating expenses associated with the 1997 Plan, the 2003 Plan, the 2005 Plan, the 2007 Plan, the 2015 Plan, the 2017 Plan, the 2019 Plan, and the 2021 Plan. T

The Rate of Return for Kentucky Power is 10.0% rate of return on equity as authorized by the Commission in its Order Dated XXXX XX, XXXX, Case No. 2025-00257. I T

Net Proceeds from the sale of emission allowances and ERCs that reflect net gains will be a reduction to the Current Period Revenue Requirement, while net losses will be an increase.

The Current Period Revenue Requirement will reflect the balances and expenses as of the Expense Month of the filing.

Continued on Sheet 33-3 T

Tariff E.S. Continued
(Environmental Surcharge)

4. Revenue Allocation

$$\text{Residential Allocation RA(m)} = \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(m)} = \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

Where:

(m) = the expense month.
(b) = the most recent calendar year revenues

5. Environmental Surcharge Factor

$$\text{Residential Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m)} * \text{RA(m)}}{\text{KY RR(m)}}$$

$$\text{All Other Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m)} * \text{AO(m)}}{\text{KY OR(m)- KY OF(m)}}$$

Where:

Net KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.

(For purposes of this formula, Total Company Revenues do not include Non-Physical Revenues.)

RR(m) = Average Kentucky Residential Retail Revenues for the Preceding Twelve Month Period

OR(m) = Average Kentucky All Other Classes Retail Revenues for the Preceding Twelve Month Period

OF(m) = Average Kentucky All Other Classes Fuel Revenues for the Preceding Twelve Month Period.

Continued on Sheet 33-4

T

Tariff E.S. Continued
(Environmental Surcharge)

6. Environmental costs "E" shall be the Company's costs of compliance with the Clean Air Act and those environmental requirements that apply to coal combustion wastes and by-products, as follows:

   Total Company:
   - return on Title IV and CSAPR SO_2 allowance inventory
   - over/under recovery balances between the actual costs incurred less the amount collected through the environmental surcharge
   - costs associated with any Commission's consultant approved by the Commission
   - costs associated with the consumption of Title IV and CSAPR SO_2 allowances
   - costs associated with the consumption of NO_x allowances
   - return on NO_x allowance inventory
   - costs associated with maintaining approved pollution control equipment including material and contract labor (excluding plant labor)
   - costs associated with consumables used in conjunction with approved environmental projects.
   - return on inventories of consumables used in conjunction with approved environmental projects.
   - return on environmental compliance rate base including construction work in progress.
   - Monthly expense associated with ARO (Asset Retirement Obligations) depreciation and accretion. DT

   The Company's share of costs associated with the following environmental equipment at the Mitchell Plant:
   - Mitchell Unit Nos 1 and 2 Water Injection, Low NO_x burners, Low NO_x burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and SO_3 Mitigation
   - Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsum Material Handling Facilities
   - Air Emission Fees
   - Precipitator Modifications and Upgrades
   - Coal Combustion Waste Landfill
   - Bottom Ash and Fly Ash Handling
   - Mercury Monitoring (MATS)
   - Dry Fly Ash Handling Conversion
   - Wastewater Ponds (for the Mitchell CCR compliance project) with depreciation expense calculated using a 20 percent depreciation rate approved by the Commission's July 15, 2021 and May 3, 2022 Orders in Case No. 2021-00004.

7. The monthly environmental surcharge shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments which shall include data and information as may be required by the Commission.

Decommissioning Rider
(D.R.)

Applicable

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L..

Rate

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2012-00578 and the Stipulation and Settlement Agreement dated July 2, 2013 as filed and approved by the Commission, Kentucky Power Company is to recover from retail ratepayers the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and other site-related retirement costs that will not continue in use on a levelized basis, including a weighted average cost of capital (WACC) as set in the Company's most recent Rate Case carrying cost over a 25 year period beginning with the date rates became effective in Case No. 2014-00396. The term "Retirement Costs" are defined as and shall include the net book value, materials and supplies that cannot be used economically at other plants owned by Kentucky Power, and removal costs and salvage credits, net of related ADIT. Related ADIT shall include the tax benefits from tax abandonment losses.

   *Pursuant to the January 19, 2024 and February 2, 2024 Orders of the Kentucky Public Service Commission in Case No. 2023-00159 collection under this rider is temporarily suspended pending the securitization of the regulatory asset. The Company will continue to accrue carrying charges on the regulatory asset at the Company's approved weighted average cost of capital until securitized bonds are issued. If Kentucky Power is unable to issue securitized bonds, collection under this rider will be reinstated.

   The applicable rates for service rendered on and after January 16, 2024 to be applied to the revenues described in paragraph 5 of this tariff are:

$$\text{Residential Adjustment Factor} = \frac{\$XX,XXX,XXX}{\$XXX,XXX,XXX} = 0.0000\%*$$

$$\text{All Other Classes Adjustment Factor} = \frac{\$XX,XXX,XXX}{\$XXX,XXX,XXX} = 0.0000\%*$$

2. The allocation of the actual revenue requirement (ARR) between residential and all other customers shall be based upon their respective contribution to total retail revenues for the most recent twelve month period, ending June 30 according to the following formula:

$$\text{Residential Allocation RA(y)} = \text{ARR(y)} \times \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(y)} = \text{ARR(y)} \times \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

Continued on Sheet 34-2

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By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Decommissioning Rider Continued

Where:

(y) = the expense year;
(b) = Most recent available twelve month period ended June 30.

3. The Residential D.R. Adjustment shall provide for annual adjustments based on a percent of total revenues, according to the following formula:

$$\text{Residential D.R. Adjustment Factor} = \frac{\text{Net Annual Residential Allocation NRA(y)}}{\text{Residential Retail Revenue RR(b)}}$$

Where:

Net Annual Residential Allocation NRA(b) = Annual Residential Allocation RA(y), net of Over/(Under) Recovery Adjustment;

Residential Retail Revenue RR(b) = Annual Retail Revenue for all KY residential classes for the year (b).

4. The All Other Classes D.R. Adjustment shall provide for annual adjustments based on a percent of non-fuel revenues, according to the following formula:

$$\text{All Other Classes D.R. Adjustment Factor} = \frac{\text{Net Annual All Other Allocation NOA(y)}}{\text{All Other Classes Non-Fuel Retail Revenue ONR(b)}}$$

Where:

Net Annual All Other Allocation NOA(y) = Annual All Other Allocation OA(y), net of Over/(Under) Recovery Adjustment;

All Other Classes Non-Fuel Retail Revenue ONR(b) = Annual Non-Fuel Retail Revenue for all classes other than residential for the year (b).

5. The Revenues to which the residential Decommissioning Rider factor are applied is the sum of the customer's Service Charge, Energy Charge(s), Demand Charge (if applicable), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Residential Energy Assistance, Purchase Power Adjustment, and Generation Rider. T

The Revenues to which the all other customer Decommissioning Rider factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Kentucky Economic Development Surcharge, Purchase Power Adjustment, and Generation Rider. T

Continued on Sheet 34-3

Decommissioning Rider Continued

6. The annual Decommissioning Rider adjustments shall be filed with the Commission no later than August 15th of each year before it is scheduled to go into effect on Cycle 1 of the October billing cycle, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

D

Securitized Surcharge Rider
(S.S.R.)

Applicable
To all retail electric customers.

Rate

1. Pursuant to the financing order of the Kentucky Public Service Commission in Case No. 2023-00159, Kentucky Power Company is to recover from retail ratepayers the costs approved for securitized bond financing by the Commission. Terms not defined in this rider shall have the meanings ascribed to those terms in that financing order.

   This rider is designed to recover from all retail electric customers the amounts necessary to service, repay and administer customer-backed securitized bonds associated with the approved securitized costs pursuant to the terms of the financing order of the Kentucky Public Service Commission in Case No. 2023-00159.

   This rider shall remain in effect until the complete repayment and retirement of any securitized bonds, or refunding bonds, associated with the approved securitized costs, together with ongoing financing costs. Upon issuance of a series of securitized bonds, this schedule is irrevocable and associated securitized surcharges are nonbypassable for the full term of that series of securitized bonds.

2. The Periodic Payment Requirement (PPR) is the required periodic payment for a given period due under the securitized bonds as further defined in the financing order.

3. Periodic Billing Requirement (PBR) shall be the aggregate dollar amount of securitized surcharges that must be billed during a given period so that the securitized surcharge collections will be sufficient to meet the sum of all PPR for that period, given: (i) forecast usage and revenue data, excluding the securitized surcharge, for the period; (ii) forecast uncollectibles for the period; and (iii) forecast lags in collection of billed securitized surcharges for the period.

4. The PBR for a given period shall be the sum of (a) the PBR for residential customers for the period (y) (Residential PBR Allocation (y)) and (b) the PBR for all other retail electric customers (non-residential retail electric customers) for the period (y) (Non-Residential PBR Allocation (y)).

5. The Residential PBR Allocation (y) shall be recovered from residential customers through application of the Residential S.S.R. Adjustment Factor to all charges on each residential customers bill for electric service, except for environmental surcharge (ES) and Decommissioning Rider (DR) charges, nonrecurring charges, and pass through charges as discussed and defined in the financing order in Case No. 2023-00159. The charges to which the Residential S.S.R. Adjustment Factor currently applies, based on that definition, are the sum of the customer's Service Charge, Demand Charge, Energy Charge(s), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Residential Energy Assistance, Purchase Power Adjustment, and Generation Rider. T T

Continued on Sheet 35-2 T

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TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Securitized Surcharge Rider Continued
(S.S.R.)

6. The Non-Residential PBR Allocation (y) shall be recovered through application of the Non-Residential S.S.R. Adjustment Factor to all charges on each non-residential retail electric customers bill for electric service, except for charges for base fuel costs and fuel cost adjustments, and environmental surcharge (ES) and Decommissioning Rider (DR) charges, nonrecurring charges, and pass through charges as discussed and defined in the financing order in Case No. 2023-00159. The charges to which the Non-Residential S.S.R. Adjustment Factor currently applies, based on that definition, are the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Kentucky Economic Development Surcharge, Purchase Power Adjustment, and Generation Rider. T T

7. The Residential S.S.R. Adjustment Factor (y) shall be calculated according to the following formula:

$$\text{Residential S.S.R. Adjustment Factor (y)} = \frac{\text{Residential PBR Allocation (y)}}{\text{Expected Residential Retail Revenue (y)}}$$

Where:

(y)	=	the given period
Expected Residential Retail Revenue (y)	=	Expected retail revenue for the period (y) from charges to which the Residential S.S.R. Adjustment Factor will apply in the period (y).

8. The Non-Residential S.S.R. Adjustment Factor shall be calculated according to the following formula:

$$\text{Non-Residential S.S.R. Adjustment Factor (y)} = \frac{\text{Non-Residential PBR Allocation (y)}}{\text{Expected Non-Residential Non-Fuel Retail Revenue NR(y)}}$$

Where:

(y)	=	the given period
Expected Non-Residential Non-Fuel Retail Revenue NR(y)	=	Expected non-fuel retail revenue for all non-residential retail electric customers for the period (y) from charges or portions of charges to which the Non-Residential S.S.R. Adjustment Factor will apply in the period (y).

9. The Residential PBR Allocation (y) shall be calculated by taking the sum of the residential true-up for the given period (y) (Residential True-up (y)) and the Residential PPR Allocation (y) and adjusting the sum to reflect both the projection of uncollectible securitized surcharges from residential customers and a projection of payment lags between the billing and collection of securitized surcharges from residential retail customers based upon the most recent experience regarding collection of securitized surcharges from residential customers.

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Securitized Surcharge Rider Continued
(S.S.R.)

10. The Non-Residential PBR Allocation (y) shall be calculated by taking the sum of the nonresidential retail electric customers true-up for the given period (y) (Non-Residential True-up (y)) and the Non-Residential PPR Allocation (y) and adjusting the sum to reflect both the projection of uncollectible securitized surcharges from non-residential retail electric customers and a projection of payment lags between the billing and collection of securitized surcharges from non-residential retail electric customers based upon the most recent experience regarding collection of securitized surcharges from non-residential retail electric customers.

11. The PPR for a given period, less the balance of the excess-funds subaccount not already accounted as part of the true-ups in paragraphs 12 and 13 and those portions of the PPR, if any, that will be collected as part of the true-ups in paragraphs 12 and 13 (PPR(y)), shall be allocated between residential customers and non-residential retail electric customers based upon their respective contributions to total retail revenues from the charges to which the Residential S.S.R. Adjustment Factor and Non-Residential S.S.R. Adjustment Factor applied and fuel costs for non-residential retail electric customers, according to the following formula:

$$\text{Residential PPR Allocation (y)} = \text{PPR(y)} \times \frac{\text{Residential Retail Revenue (b)}}{\text{KY Retail Revenue (b)}}$$

$$\text{Non-Residential PPR Allocation (y)} = \text{PPR(y)} \times \frac{\text{Non-Residential Retail Revenue (b)}}{\text{KY Retail Revenue (b)}}$$

Where:

(y)	=	the given period
(b)	=	Most recent available twelve-month period ended December 31 or June 20
Residential Retail Revenue (b)	=	Retail revenue for residential retail electric customers for the period (b) from charges to which Residential S.S.R. Adjustment Factor applied in the period (b) (or to which it would have applied if the adjustment factor was not applicable during all or a portion of the period).
Non-Residential Retail Revenue (b)	=	Retail revenue for all non-residential retail electric customers for the period (b) from charges to which the Non-Residential S.S.R. Adjustment Factor applied (or to which it would have applied if the adjustment factor was not applicable during all or a portion of the period) and charges for base fuel and pursuant to the fuel adjustment clause.
KY Retail Revenue (b)	=	Residential Retail Revenue (b) + Non-Residential Retail Revenue (b).

12. The Residential True-up (y) shall be calculated by subtracting the cumulative revenues collected from the Residential S.S.R. Adjustment Factor through the preceding period from the cumulative Residential PPR Allocation for all periods through the preceding period, in which the preceding period is the period ending on the date on which Residential S.S.R. Adjustment Factor (y) goes into effect.

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Securitized Surcharge Rider Continued
(S.S.R.)

13. The Non-Residential True-up (y) shall be calculated by subtracting the cumulative revenues collected from the Non-Residential S.S.R. Adjustment Factor through the preceding period from the cumulative Non-Residential PPR Allocation for all periods through the preceding period, in which the preceding period is the period ending on the date on which Non-Residential S.S.R. Adjustment Factor (y) goes into effect.

14. Notwithstanding the foregoing:

    A. the Residential S.S.R. Adjustment Factor to be used for the applicable true up filing shall be the greater of (i) the Residential S.S.R. Adjustment Factor (y), where (y) is the period beginning on the date on which the applicable true-up adjustment would go into effect and ending on the next payment date after the effective date of each true-up adjustment (Calculation Period A), and (ii) the Residential S.S.R. Adjustment Factor (y), where (y) is the period beginning on the date on which the applicable true-up adjustment would go into effect and ending on the second payment date after the effective date of such true-up adjustment (Calculation Period B);

    B. the Non-Residential S.S.R. Adjustment Factor to be used for the applicable true-up filing shall be the greater of (i) the Non-Residential S.S.R. Adjustment Factor (y), where (y) us Calculation Period A, and (ii) the Non-Residential S.S.R. Adjustment Factor (y), where (y) is Calculation Period B;

    C. the Residential PBR Allocation (y) referenced in paragraph 5 shall be with respect to the same period (y) as used for the Residential S.S.R. Adjustment Factor (y) selected under clause (A) above; and

    D. the Non-Residential PBR Allocation (y) referenced in paragraph 6 shall be with respect to the same period (y) as used for the Non-Residential S.S.R. Adjustment (y) selected under clause (B) above.

15. The initial Residential S.S.R. Adjustment Factor and Non-Residential S.S.R. Adjustment Factor shall be filed on the day following the pricing of each series of securitized bonds, shall be calculated based on the formulas in paragraphs 7 and 8, respectively, and shall become effective the first billing cycle following the closing of the securitized bonds. The Residential S.S.R. Adjustment Factor and Non-Residential S.S.R. Adjustment Factor shall initially be adjusted on March 1, 2026 and thereafter be adjusted at least semi-annually (every six months) along with all the necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

    Quarterly true-ups will begin 12 months prior to the scheduled final payment date for the latest maturing tranche of securitized bonds of a particular series.

    Interim Securitized Surcharge Rider adjustments may be filed with the Commission outside of the standard semi-annual or quarterly timeframe in order to correct for over- or under-collection to be submitted no later than 10 days before the rate is to be effective.

    Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

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T

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Securitized Surcharge Rider Continued
(S.S.R.)

T

16. The applicable rates for service rendered on and after June 30, 2025 to be applied to the revenues described in paragraphs 5 and 6 of this tariff are:

$$\text{Residential S.S.R. Adjustment Factor} = \frac{\$12,162,339}{\$172,017,997} = 7.0704\%$$

$$\text{Non-Residential S.S.R. Adjustment Factor} = \frac{\$15,620,679}{\$142,477,952} = 10.9636\%$$

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Federal Tax Cut Tariff
(F.T.C.)

Applicable

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L.

Rate

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2023-00159, Kentucky Power Company is to credit to retail ratepayers the approved annual amount of excess accumulated deferred federal income taxes (ADIT) beginning January 16, 2024.

2. The Company shall amortize the calendar year retail Generation and Distribution related Protected Excess ADIT of $1,410,730 to support the rate credits provided to customers through this tariff. R

3. The Company shall provide customers with the ADIT benefit related to Non-Decommissioning Rider Regulatory Assets (defined as the Rockport Deferral Regulatory Asset, Tariff P.P.A. Under-Recovery Regulatory Asset, and Storm Expense Deferral Regulatory Assets) approved for securitization through this tariff, at its Commission-approved WACC. The ADIT benefit described in this paragraph will be annually trued-up to address over/(under) recovery pursuant to the procedure described in paragraph 8 of this tariff. TD

4. Upon receipt of a Private Letter Ruling from the IRS affirming the Company's analysis that excluding its NOLC adjustment from rates would constitute a normalization violation, recovery of the NOLC regulatory asset established in accordance with the Commission's January 19, 2024 Order in Case No. 2023-00159 over a three-year period starting XXXX XX, XXXX. T

5. The Company shall include a final reconciliation of the retail Generation and Distribution related Unprotected Excess ADIT as part of the over or under-recovery computation in the October 2024 Federal Tax Cut Tariff adjustment filing. T

6. The applicable rates on a kWh basis are as follows: T

Residential ($/kWh)	All Other ($/kWh)
$(0.00068)	$(0.00047)

Continued on Sheet 36-2 T

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Federal Tax Cut Tariff Continued
(F.T.C.)

T

7. The allocation of the Annual Revenue Requirement (ARR) which consists of the retail Generation and Distribution related Protected Excess ADIT, the ADIT benefits related to the securitized Non-Decommissioning Rider Regulatory Assets and any over or under-recovery based upon actual information for prior periods between residential and all other customers shall be based upon their respective contribution to total retail revenues, according to the following formula: T

$$\text{Residential Allocation } RA(y) = AC(y) \times \frac{\text{KY Residential Retail Revenue RR}}{\text{KY Retail Revenue R}}$$

$$\text{All Other Allocation } OA(y) = AC(y) \times \frac{\text{KY All Other Classes Retail Revenue OR}}{\text{KY Retail Revenue R}}$$

Where:

(y)	=	the credit year;
RR	=	$263,446,618;
OR	=	$347,727,039; and
R	=	$611,173,657.

8. The annual Federal Tax Cut Tariff adjustments shall be filed with the Commission no later than October 15th of each year before it is scheduled to go into effect on Cycle 1 of the December billing cycle, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission. T

9. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884. T

Tariff C.F.F.
(City's Franchise Fee)

Availability of Service

Where a city or town within Kentucky Power's service territory requires the Company to pay a percentage of revenues from certain customer classifications collected within such city or town for the right to erect the Company's poles, conductors, or other apparatus along, over, under, or across such city's or town's streets, alleys, or public grounds, the Company shall increase the rates and charges to such customer classifications within such city or town by a like percentage. The aforesaid charge shall be separately stated and identified on each affected customer's bill.

U.G.R.T.
(Utility Gross Receipts Tax)
(School Tax)

Applicable
To all Tariff Schedules.

Rate
This tariff schedule is applied as a rate increase pursuant to KRS 160.617 to all other tariff schedules for the recovery by the utility of the utility gross receipts license tax imposed by the applicable school district pursuant to KRS 160.613 with respect to the customer's bill. The current utility gross receipts license tax for school imposed by a school district may not exceed 3%. The utility gross receipts license tax shall appear on the customer's bill as a separate line item.

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In Case No.: 2025-00257 Dated XXXX XX, XXXX

K.S.T.
(Kentucky Sales Tax)

Applicable
To all Tariff Schedules.

Rate
This tariff schedule is applied as a rate increase to all other applicable tariff schedules for the recovery by the utility pursuant to KRS 139.210 of the Kentucky Sales Tax imposed by KRS 139.200 for all customers not exempted by KRS 139.470(7). For any other exempt customers, an exemption certification must be received and on file with the Company. The Kentucky Sales Tax rate is currently imposed by the Commonwealth of Kentucky at the rate of 6%. The Kentucky Sales Tax shall appear on the customer's bill as a separate line item.

Sales of electricity under Tariff R.S. are exempt from sales tax only if the service is to the customer's place of domicile as defined by KRS 139.470(7)(b). Kentucky Power may retroactively charge a customer, under the parameters of KRS 278.225, for all applicable sales tax the Department of Revenue determines is due for service that is not exempt. It is the customer's responsibility to file all necessary documentation, including Form 51A380 (1-23), when notified by the Company, establishing the customer's place of domicile. In such a case, any exemption will become effective with the customer's first full billing cycle after the customer's delivery of a properly executed Form 51A380 (1-23).

P.S.C. KY. NO. 14~~13~~
CANCELLING P.S.C. KY. NO. 13~~12~~

Kentucky Power Company

1645 Winchester Avenue
Ashland, KY 41101
www.kentuckypower.com

Rates, Terms, and Conditions for Furnishing
Electric Service

Applicable to the Entire Territory Served by Kentucky Power Company In: Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Johnson, Knott, Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike, and Rowan Counties.

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ISSUED BY: /s/ ~~Brian K. West~~Tanner S. Wolffram
TITLE: ~~Vice President, Regulatory & Finance~~Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated ~~January 19, 2024~~XXXX XX, XXXX

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DATE OF ISSUE: August 29, 2025~~April 4, 2025~~
DATE EFFECTIVE: Services Rendered On and After March 1, 2026~~March 18, 2025~~
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2024-00305~~ Dated XXXX XX, XXXX~~March 18, 2025~~

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Terms and Conditions of Service

1. Application

Applications may be made in writing, on-line, or via telephone for customers who wish to have the Company provide electric service. Requests for service are to be made in the Customer's legal name by telephone or online at: www.kentuckypower.com. The Company has the right to reject any request for service based on 807 KAR 5:006 Section 15 and associated tariffs.

The Company may require verification of ownership of property, lease, applicant's identity, or other requested information.

A copy of the tariffs and standard terms and conditions under which service is to be rendered to the Customer will be furnished upon request and the Customer shall elect upon which tariff applicable to his service his application shall be based. A copy of the tariff is also available online at www.kentuckypower.com.

If the Company requires a written agreement from a Customer before service will be commenced, a copy of the agreement will be furnished to the Customer upon request.

When the Customer desires delivery of energy at more than one point, a separate agreement may be required for each separate point of delivery. Service delivered at each point of delivery will be billed separately under the applicable tariff.

2. Inspection

The Customer is responsible for the proper installation and maintenance of the customer's wiring and electrical equipment and the customer shall at all times be responsible for the character and condition thereof. The Company has no obligation to undertake inspection thereof and in no event shall be responsible therefore. However, the Company may disconnect or refuse to connect service if the customer's wiring is deemed unsafe by the Company.

Company may also require a new state electrical inspection should tampering, illegal use or theft of service be the basis for disconnection service.

Where a Customer's premises are located in a municipality or other governmental subdivision where inspection laws or ordinances are in effect, the Company may withhold furnishing service to new installations until the Company has received evidence that the inspection laws or ordinances have been complied with.

Where a Customer's premises are located outside of an area where inspection service is in effect, the Company may require the delivery by the Customer to the Company of an agreement duly signed by the owner and/or tenant of the premises authorizing the connection to the wiring system of the Customer and assuming responsibility therefore. No responsibility shall attach to the Company because of any waiver of this requirement.

3. Service Connections

Service connections will be provided in accordance with 807 KAR-5:041, Section 10.

The Customer should in all cases consult the Company before the Customer's premises are wired to determine the location of Company's point of service connection.

Continued on Sheet 2-2

Terms and Conditions of Service Continued

Service Connections Continued

The Company will, when requested to furnish service, designate the location of its service connection. The Customer's wiring must, except for those cases listed below, be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto. When service is from an overhead system, the Customer's wiring must extend at least 18 inches beyond the building. Where Customers install service entrance facilities which have capacity and layout specified by the Company and/or install and use certain equipment specified by the Company, the Company may supply or offer to own certain facilities on the Customer's side of the point where the service wires attach to the building
All inside wiring must be grounded in accordance with the requirements of the National Electrical Code or the requirements of any local inspection service authorized by a state or local authority.

When a Customer desires that energy be delivered at a point or in a manner other than that designated by the Company, the Customer shall pay the additional cost of same.

4. Deposits

Prior to providing service or at any time thereafter, the Company may require a cash deposit or other guaranty acceptable to the Company to secure payment of bills except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection. Service may be refused or discontinued for failure to pay the requested deposit. Upon request from a residential customer the deposit will be returned after 18 months if the customer has established a satisfactory payment record; but commercial deposits will be retained by the Company during the entire time that the account remains active.

A. Interest

Interest will be paid on all sums held on deposit at the rate indicated in KRS 278.460. The interest will be applied by the Company as a credit to the Customer's bill or will be paid to the Customer on an annual basis. If the deposit is refunded or credited to the Customer's bill prior to the deposit anniversary date, interest will be paid or credited to the Customer's bill on a pro-rated basis.

The Company will not pay interest on deposits after discontinuance of service to the Customer. Retention of any deposit or guaranty by the Company prior to final settlement is not a payment or partial payment of any bill for service. The Company shall have a reasonable time in which to obtain a final reading and to ascertain that the obligations of the Customer have been fully performed before being required to return any deposits.

B. Criteria for Waiver of Deposit Requirement

The Company may waive any deposit requirement based upon the following criteria, which may be considered by the Company cumulatively:

i. Satisfactory payment history with the Company, which may be established by paying all bills by due date, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments and having no energy diversion or theft of service;
ii. Satisfactory payment history with another utility acceptable to the Company;
iii. Another customer with satisfactory payment history is willing to sign as a guarantor for an amount equal to the required deposit; or
iv. Providing evidence of other collateral acceptable to Company.

Continued on Sheet 2-3

Terms and Conditions of Service Continued

C. Method of Determination – Calculated Deposits

a. Deposit amounts paid by residential customers shall not exceed a calculated amount based upon actual usage data of the Customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the average bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the Customer's actual or estimated annual bill.

b. Deposit amounts paid by commercial and industrial customers shall not exceed a calculated amount based upon actual usage data of the customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the typical bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the customer's actual or estimated annual bill.

D. Additional or Supplemental Deposit Requirement

An additional or supplemental deposit may be required if the Customer does not maintain a satisfactory credit criteria or payment history. If a change in usage or classification of service has occurred, the customer may be required to pay an additional deposit up to 2/12 of the annual usage. The Customer will receive a message on the bill informing the Customer that if the account is not current by the specified date listed an additional or supplemental deposit will be charged to the account the next time the account is billed.

i. Satisfactory payment history is defined as paying all bills by due date, having no disconnections for nonpayment, having no defaulted credit arrangements, having no returned payments and having no meter diversion or theft of service.

ii. A nonresidential customer does not maintain satisfactory credit criteria when its credit score at any national independent credit rating service falls to a level that is deemed to present a risk of nonpayment, including but not limited to: below a "BB+" level at Standard and Poor's or below "Ba1" at Moody's. If a nonresidential customer is not rated by a national independent credit rating service, its credit may be evaluated by using credit scoring services, public record financial information, or financial scoring and modeling services, and if it is deemed that the customer presents a risk of nonpayment, a deposit may be required.

E. Recalculation of Customer Deposit

When a deposit is held longer than 18 months, the Customer may request that the deposit be recalculated based on the Customer's actual usage. If the amount of deposit on the account differs from the recalculated amount by more than $10.00 for a residential Customer or 10 percent for a non-residential Customer, the Company may collect any underpayment and shall refund any overpayment. No refund will be made if the Customer's bill is delinquent at the time of the recalculation.

5. Payments

Bills will be rendered by the Company to the Customer monthly or in accordance with the tariff selected applicable to the Customer's service.

A. Equal Payment Plan (Budget)

Nonresidential customers with accounts that are current and that maintain satisfactory credit criteria per paragraph 4(D) above and all residential customers have the option of paying a fixed amount each month under the Company's Equal Payment Plan. The monthly payment amount will be based on one-twelfth of the Customer's estimated annual usage. The payment amount is subject to periodic review and adjustment during the budget year to more accurately reflect actual usage. The normal plan period is 12 months, which may commence April through December.

Continued on Sheet 2-4

Terms and Conditions of Service Continued

Equal Payment Plan (Budget) Continued

In the last month of the plan (the "settle-up month") if the actual usage during the plan period exceeds the amount billed, the Customer will be billed for the balance due. If an overpayment exists, the amount of overpayment will either be refunded to the Customer or credited to the last bill of the period. If a Customer discontinues service with the Company under the Equal Payment Plan, any amounts not yet paid shall become payable immediately.

If a Customer fails to pay bills as rendered under the Equal Payment Plan, the Company reserves the right to revoke the plan, restore the Customer to regular billing, require immediate payment of any deficiency, and require a cash deposit or other guaranty to secure payment of bills.

Customers currently enrolled in the Equal Payment Plan whose settle-up month falls within the period December through February may elect to change their settle-up month to November or March if their Equal Payment Plan account is current.

If a customer who is currently enrolled in the Equal Payment Plan elects to take service under Tariff N.M.S. II, such customer will be removed from the Equal Payment Plan and restored to regular billing. Additionally, if a customer who is currently enrolled in the Equal Payment Plan elects to take service under Tariff FlexPay, such customer will be removed from the Equal Payment Plan and billed on a pay as they use basis.

B. Average Monthly Payment Plan

The Average Monthly Payment Plan (AMP Plan) is available to all residential customers and nonresidential customers with accounts that are current and that maintain satisfactory credit criteria per paragraph 4(D) above.

The AMP Plan is designed to allow the Customer to pay an average amount each month based upon the actual billed amounts during the past twelve (12) months. The average payment amount is based upon the current month's total bill plus the eleven (11) preceding months. That result is divided by the total billing days associated with the billings to determine a per day average. The daily average amount is multiplied by thirty (30) to determine the current month's payment under the AMP Plan. At the next billing period, the oldest month's billing history is removed, the current month's billing is added and the total is again divided by the total billing days associated with the billings to determine a per day average. Again the daily average amount is multiplied by thirty (30) to find the new average payment amount. The average monthly payment amount is calculated each and every month in this manner.

If a customer who is currently enrolled in the AMP Plan elects to take service under Tariff N.M.S. II, such customer will be removed from the AMP Plan and restored to regular billing. Additionally, if a customer who is currently enrolled in the AMP Plan elects to take service under Tariff FlexPay, such customer will be removed from the AMP Plan and billed on a pay as they use basis.

Continued on Sheet 2-5

Terms and Conditions of Service Continued

Average Monthly Payment Plan Continued

The difference between the actual billings and the AMP Plan billings will be carried in a deferred balance. Both the debit and credit differences will accumulate in the deferred balance for the duration of the AMP Plan year, which is twelve (12) consecutive billing months. At the end of the AMP Plan year (anniversary month), the current month's billing plus the eleven (11) preceding month's billing is summed and divided by the total billing days associated with the billings to determine a per day average. That result is multiplied by thirty (30) to calculate the AMP Plan's monthly payment amount. In addition, the net accumulated deferred balance is divided by 12. This result is added or subtracted to the calculated average payment amount starting with the next billing of the new AMP plan year and will be used in the average payment amount calculation for the remaining AMP plan year. Settlement occurs only when participation in the AMP Plan is terminated. This happens if any account is final billed, if the customer requests termination, or at the Company's discretion when the customer fails to make two or more consecutive monthly payments on an account by the due date. The deferred balance (debit or credit) is then applied to the billing now due.

In such instances where sufficient billing history is not available, an AMP Plan may be established by using the actual billing history available throughout the first AMP Plan year.

C. All Payments

All bills are due and payable within twenty-one (21) days after their mailing date. Failure to receive a bill will not entitle a Customer to any discount or to the remission of any charges for non-payment within the time specified. The word "month" as used herein and in the tariffs is hereby defined to be the elapsed time between 2 successive meter readings approximately 30 days apart.

In the event of the stoppage of or the failure of any meter to register the full amount of energy consumed, the Customer will be billed for the period based on an estimated consumption of energy in a similar period of like use.

Delayed Payment Charge

The tariffs of the Company are met if the account of the Customer is paid within the time limit specified in the tariff applicable to the Customer's service. Residential customers are not subject to a delayed payment charge. On all non-residential accounts not so paid, an additional charge of 5% of the unpaid balance will be applied. Any one delayed payment charge billed against the Customer for non-payment of bill or any one forfeited discount applied against the Customer for non-payment of bill may be remitted, provided the Customer's previous accounts are paid in full and provided no delayed payment charge or forfeited discount has been remitted under this clause during the preceding six months.

6. Payment Arrangements

In accordance with 807 KAR 5:006 Section 14(2), Kentucky Power shall negotiate and accept reasonable payment arrangements at the request of a residential customer who has received a termination notice for failure to pay. Payment arrangements will include the following reasonable provisions:

a. Partial Payment Plans are available up to the day prior to the termination date printed on a customer's termination notice.
b. Partial Payment Plans are available only for current balances and balances up to 30 days in arrears.
c. Any balance more than 30 days in arrears must be paid in full at least one business day prior to the date the Partial Payment Plan is established.
d. Customers with delinquent or otherwise unsatisfied Partial Payment Plans may not be eligible for a Partial Payment Plan.

Continued on Sheet 2-6

Terms and Conditions of Service Continued

Payment Arrangements Continued

e. Unpaid deposit amounts are not eligible for inclusion in a Partial Payment Plan.
f. Company reserves the right to refuse unverifiable third-party pledges toward a customer's obligations under a Partial Payment Plan.
g. Customer shall be advised, in writing or by telephone, the date and the amount of payment(s) due. Service may be terminated without additional notice if the Customer fails to meet the obligations of the agreed plan.
h. It is the responsibility of the customer presenting the Medical Certificate to contact the Company to negotiate a payment arrangement based upon the customer's ability to pay. The payment arrangement shall require that the account become current no later than October 15.
i. Customers presenting Certification from the Cabinet for Health and Family Services must do so during the initial 10 day termination notice period. As a condition of the 30-day extension, the customer shall exhibit good faith by entering into a payment arrangement.

7. Underground Service

When a real estate developer desires an underground distribution system within the property which he is developing or when a Customer desires an underground service, the real estate developer or the Customer as the case may be, shall pay the Company the difference between the anticipated cost of the underground facilities so requested and the cost of the overhead facilities which would ordinarily be installed in accordance with 807 KAR 5:041, Section 21, and the Company's underground service plan as filed with the Public Service Commission. Upon receipt of payment, the Company will install the underground facilities and will own, operate and maintain the same.

Please see Tariff Sheet No. 14-1 for the underground differential cost schedule.

8. Company's Liability

The Company will use reasonable diligence in furnishing a regular and uninterrupted supply of energy, but does not guarantee uninterrupted service. The Company shall not be liable for damages in case such supply should be interrupted or fail by reason of an event of Force Majeure. Force Majeure consists of an event or circumstance which prevents Company from providing service, which event or circumstance was not anticipated, which is not in the reasonable control of, or the result of negligence of, the Company, and which, by the exercise of due diligence, Company is unable to overcome or avoid or cause to be avoided. Force Majeure events includes acts of God, the public enemy, accidents, labor disputes, orders or acts of civil or military authority, breakdowns or injury to the machinery, transmission lines, distribution lines or other facilities of the Company, or extraordinary repairs.

Unless otherwise provided in a contract between the Company and Customer, the point at which service is delivered by Company to Customer, to be known as "delivery point," shall be the point at which the Customer's facilities are connected to the Company's facilities. The metering device is the property of the Company. The meter base, connection, grounds and all associated internal parts inside the meter base are customer owned and are the responsibility of the customer to install and maintain. The Company shall not be liable for any loss, injury, or damage resulting from the Customer's use of their equipment or occasioned by the energy furnished by the Company beyond the delivery point.

Any new installation, upgrade or other modification of an existing meter installation shall be made using only Company-supplied or Company-approved meter bases. A list of Company-approved meter bases and specifications can be found on the Company's website at: www.kentuckypower.com.

Continued on Sheet 2-7

Terms and Conditions of Service Continued

Company's Liability Continued

The Customer shall provide and maintain suitable protective devices on their equipment to prevent any loss, injury or damage that might result from single phasing conditions or any other fluctuation or irregularity in the supply of energy. The Company shall not be liable for any loss, injury or damage resulting from a single phasing condition or any other fluctuation or irregularity in the supply of energy which could have been prevented by the use of such protective devices. The Company shall not be liable for any damages, whether direct, incidental or consequential, including, without limitation, loss of profits, loss of revenue, or loss of production capacity occasioned by interruptions, fluctuations, or irregularity in the supply of energy.

The Company is not responsible for loss or damage caused by the disconnection or reconnection of its facilities. The Company is not responsible for loss or damages caused by the theft or destruction of Company facilities by a third party.

The Company will provide and maintain the necessary line or service connections, transformers (when same are required by conditions of contract between the parties thereto), meters and other apparatus, which may be required for the proper measurement of and protection to its service. All such apparatus shall be and remain the property of the Company.

9. Customer's Liability

In the event of loss or injury to the property of the Company through misuse by, or the negligence of, the Customer or the employees of the same, the cost of the necessary repairs or replacement thereof shall be paid to the Company by the Customer.

Customers will be responsible for tampering with, interfering with, or breaking the seals of meters, or other equipment of the Company installed on the Customer's premises. The Customer hereby agrees that no one except the employees of the Company shall be allowed to make internal or external adjustments to any meter or any other piece of apparatus, which shall be the property of the Company.

The Company shall have the right at all reasonable hours to enter the premises of the Customer for the purpose of installing, reading, removing, testing, replacing or otherwise disposing of its apparatus and property, and the right of entire removal of the Company's property in the event of the termination of the contract for any cause. The Company may assess charges based on electric usage and damages to all Company equipment.

10. Extension of Service

The electric facilities of the Company shall be extended or expanded to supply electric service to all residential Customers and small commercial Customers which require single phase line where the installed transformer capacity does not exceed 25 KVA in accordance with 807 KAR 5:041, Section 11.

The electric facilities of the Company shall be extended or expanded to supply electric service to Customers other than those named in the above paragraph when the estimated revenue is sufficient to justify the estimated cost of making such extensions or expansions as set forth below.

Continued on Sheet 2-8

Terms and Conditions of Service Continued

Extension of Service Continued

For services to be delivered to Commercial, Industrial, Mining and multiple housing project Customers up to and including estimated demands of 500 KW requiring new facilities, the Company will: (a) where the estimated revenue for one year exceeds the estimated installed cost of new local facilities required, provide such new facilities at no cost to the Customer; (b) where the estimated revenue for one year is less than the installed cost of new local facilities required, the Customer will be required to pay a contribution in aid of construction equal to the difference between the installed cost of the new facilities required to service the load and the estimated revenue for one year; (c) if the Company has reason to question the financial stability of the Customer and/or the life of the operation is uncertain or temporary in nature, such as construction projects, oil and gas well drilling, sawmills and mining operations, the Customer shall pay a contribution in aid of construction, consisting of the estimated labor cost to install and remove the facilities required plus the cost of unsalvageable material, before the facilities are installed.

For service to be delivered to Customers with demand levels higher than those specified above, the annual cost to serve the Customer's requirements shall be compared with the estimated revenue for one year to determine if a contribution in aid of construction, and/or a special minimum and/or other arrangement may be necessary. The annual cost to serve shall be the sum of the following components:

i. The annual fixed costs of the generation, transmission and distribution facilities related to the Customer's requirements. These fixed costs will be calculated at 21.95% of the value to be based on the year-end embedded investment depreciated in all similar facilities of the Company.
ii. The annual energy cost based on the latest available production costs related to the Customer's estimated annual energy use requirements.
iii. The annual fixed costs of the new local facilities necessary to provide the service requested calculated at 21.95% of the installed cost of such facilities.

If the estimated revenue for one year is greater than the cost to serve as describe herein, the Company may provide any new local facilities required at no cost to the Customer. If the estimated revenue for one year is less than the cost to serve as described herein, the Company will require the Customer to pay a contribution in aid of construction equal to the difference between the annual cost to serve as calculated and the estimated revenue for one year divided by 21.95%, but in no case to exceed the installed cost of the new facilities required. If, however, the annual cost to serve excluding the cost of new facilities paid for by the Customer exceeds the estimated revenue for one year, the Company, will, in addition to a contribution in aid of construction, require a special minimum or other arrangement to compensate the Company for such deficiency in venue.

Except where service is rendered in accordance with 807 KAR 5:041, Section 11, as described herein, the Company may require the Customer to execute an Advance and Refund Agreement where the Company reasonably questions the longevity of the service or the estimated energy use and demand requirements provided by the Customer. Under the Advance and Refund Agreement, the Customer shall pay the company the estimated total installed cost of the required new facilities which advance could be refunded over a five year period under certain circumstances. Over the five year period the Customer' electric bill would be credited each month up to the amount of 1/60th of the total amount advanced.

11. Extension of Service to Mobile Home

The electrical facilities of the Company will be extended or expanded to supply electric service to mobile homes in accordance with 807 KAR 5:041, Section 12.

Continued on Sheet 2-9

Terms and Conditions of Service Continued

12. Location and Maintenance of Company Equipment

The Company shall have the right to construct its poles, lines and circuits on the property, and to place its transformers and other apparatus on the property or within the building of the Customer, at a point or points convenient for such purposes, as required to serve such Customer, and the Customer shall provide suitable space for the installation of necessary measuring instruments so that the latter may be protected from injury by the elements or through the negligence or deliberate acts of the Customer or of any employee of the same.

13. Billing Form

Pursuant to 807 KAR 5:006, Section 7, copies of the billing forms used by the Company are shown on Sheet Nos. 2-17~~2-14~~ thru 2-26~~2-23~~.

14. Rate Schedule Selection

The Company will explain to the Customer, at the beginning of service or upon request, the Company's rates available to the Customer. Company will assist Customer in the selection of the rate schedule best adapted to Customer's service requirements, provided, however, that Company does not assume responsibility for the selection or that Customer will at all times be served under the most favorable rate schedule.

Customer may change their initial rate schedule selection to another applicable rate schedule at any time by either written notice to Company and/or by executing a new contract for the rate schedule selected, provided that the application of such subsequent selection shall continue for 12 months before any other selection may be made. In no case will the Company refund any monetary difference between the rate schedule under which service was billed in prior periods and the newly selected rate schedules.

15. Monitoring Usage

At least once quarterly the Company will monitor the usage of each customer according to the following procedure:

a. The Customer's monthly usage will be compared with the usage of the corresponding period of the previous year.
b. If the monthly usage for the two periods is substantially the same or if any difference is known to be attributed to unique circumstances, such as unusual weather conditions, common to all customers, no further review will be made.
c. If the monthly usage is not substantially the same and cannot be attributed to a readily identified common cause, the Company will compare the Customer's monthly usage records for the 12-month period with the monthly usage for the same months of the preceding year.
d. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, the company will contact the Customer to determine whether there have been changes that explain the increased or decreased usage.
e. Where the deviation is not otherwise explained, the Company will test the Customer's meter to determine whether it shows an average error greater than 2 percent fast or slow.
f. The Company will notify the Customer of the investigation, its findings, and any refunds or back billing in accordance with 807 KAR 5:006, Section 11(4) and (5).

In addition to the quarterly monitoring, the Company will immediately investigate usage deviations brought to its attention as a result of its on-going meter reading, billing processes, or customer inquiry.

Continued on Sheet 2-10

Terms and Conditions of Service Continued

16. Use of Energy by Customer

The tariffs for electric energy given herein are classified by the character of use of such energy and are not available for service except as provided herein.

Upon the expiration of an electric service contract, if required by the terms of the tariff, the Customer may elect to renew the contract upon the same or another tariff published by the Company available to the Customer and applicable to the Customer's requirements, except that in no case shall the Company be required to maintain transmission, switching or transformation equipment different from or in addition to that generally furnished to other Customers receiving electrical supply under the terms of the tariff elected by the Customer.

The service connections, transformers, meters and appliances supplied by the Company for each Customer have a definite capacity and no additions to the equipment, or load connected thereto, will be allowed except by consent of the Company.

~~**Use of Energy by Customer Continued**~~

The Customer shall install only motors, apparatus or appliances which are suitable for operation with the character of the service supplied by the Company, and which shall not be detrimental to same, and the electric energy must not be used in such a manner as to cause unprovided-for voltage fluctuations or disturbances in the Company's transmission or distribution system. The Company shall be the sole judge as to the suitability of apparatus or appliances, and also as to whether the operation of such apparatus or appliances is or will be detrimental to its general service.

No attachment of any kind whatsoever may be made to the Company's lines, poles, cross arms, structures or other facilities without the express written consent of the Company.

All apparatus used by the Customer shall be of such type as to secure the highest practicable commercial efficiency, power factor and the proper balancing of phases. Motors which are frequently started or motors arranged for automatic control must be of a type to give maximum starting torque with minimum current flow, and must be of a type, and equipped with controlling devices, approved by the Company. The Customer agrees to notify the Company of any increase or decrease in his connected load

The Company will not supply service to Customers who have other sources of electrical energy supply except under tariffs that specifically provide for same.

The Customer shall not be permitted to operate generating equipment in parallel with the Company's service except with express written consent of the Company.

Resale of energy will be permitted only with express written consent by the Company.

17. Residential Service

Except as otherwise provided in these tariffs, individual residences shall be served individually with single-phase secondary service under the applicable residential service tariff. Customer may not take service for 2 or more separate residences through a single point of delivery under any tariff. Exclusions may be allowed pursuant to 807 KAR 5:046 (Prohibition of master metering).

Continued on Sheet 2-11

Terms and Conditions of Service Continued

Residential Service Continued

The residential service tariff shall cease to apply to that portion of a residence which becomes regularly used for business, professional, institutional or gainful purposes, which requires three phase service or primary service or which requires service to motors in excess of 10 HP each. Under these circumstances, Customer shall have the choice of: (1) separating the wiring so that the residential portion of the premises is served through a separate meter under the residential service tariff, and the other uses as enumerated above are served through a separate meter or meters under the applicable general service tariff; or (2) taking the entire service under the applicable general service tariff.

Detached building or buildings, actually appurtenant to the residence, such as a garage, stable or barn, may be served by an extension of the Customer's residence wiring through the residence meter and under the applicable residential service tariff.

18. Denial or Discontinuance of Service

The Company reserves the right to refuse or discontinue service to any customer if the customer is indebted to the Company for any service theretofore rendered at any location. Service will not be supplied or continued to any premises if at the time of application for service the Applicant is merely acting as an agent or person or former customer who is indebted to the Company for service previously supplied at the same, or other premises, until payment of such indebtedness shall have been made.

~~**Denial or Discontinuance of Service Continued**~~

Unpaid balances of previously rendered Final Bills may be transferred to any account for which Customer has responsibility and may be included on initial or subsequent bills for the account to which the transfer was made. Such transferred Final Bills, if unpaid, will be a part of the past due balance of the account to which they are transferred. When there is no lapse in service, such transferred Final Bills will be subject to Company's collections and disconnect procedures in accordance with 807 KAR 5:006, Section 15(1)(f). Final Bills transferred following a lapse in service will not be subject to disconnection unless: (1) such service was provided pursuant to a fraudulent application submitted by Customer; (2) Customer and Company have entered into a contractual agreement which allows for such a disconnection; or (3) the current account is subsequently disconnected for service supplied at that point of delivery, at which time, all unpaid and past due balances must be paid prior to reconnect.

Residential disconnections are limited to the hours of 8:00 a.m. through 5:00 p.m. Monday through Thursday and 8:00 a.m. through noon on Friday.

Residential service will not be disconnected for 24 hours following when temperatures are forecast to be 32 degrees or below or 95 degrees or higher.

Continued on Sheet 2-12

Terms and Conditions of Service Continued

19. Special Charges

a. Reconnection and Disconnect Charges

In cases where the Company has discontinued service as herein provided for, the Company reserves the right to assess a reconnection charge pursuant to 807 KAR 5:006, Section 9 (3)(b), payable in advance, in accordance with the following schedule. However, those Customers qualifying for Winter Hardship Reconnection under 807 KAR 5:006 Section 16 shall be exempt from the reconnect charges.

Reconnect for nonpayment during regular hours for non-remote reconnection meters	$54.114.70
Reconnect at the end of the day (no "Call Out" required) for non-remote reconnection meters	$137.2030.00
Reconnect for nonpayment when a "Call Out" is required prior to 8:00 p.m. for non-remote reconnection meters (A "Call Out" is when an employee must be called in to work on overtime basis to make the reconnect trip. Reconnection for nonpayment will not be made when a "Call Out" after 8:00 p.m. is required)	$137.2095.00
Reconnect for nonpayment when double time is required (Sunday and Holiday) for non-remote reconnection meters	$178.75124.00
Reconnect for nonpayment for meters with remote reconnection capability	$0.00
Termination or field trip	$54.114.70

The reconnection charge for all Customers where service has been disconnected for fraudulent use of electricity will be the actual cost of the reconnection.

b. Meter Read Check

Pursuant to 807 KAR 5:006, Section 9(3)(d) in cases where a customer requests a meter be reread, and the second reading shows the original reading was correct, the Customer will be charged a fee of $54.1121.00 to cover the handling cost.

c. Returned Check Charge

In cases where a customer pays by check, which is later returned as unpaid by the bank for any reason, the Customer will be charged a fee of $6.6014.65 to cover the handling costs.

d. Meter Test Charge

Where test of a meter is made upon written request by the Customer pursuant to 807 KAR 5:006, Section 19, the Customer will be charged $74.8848.00 if such test shows that the meter was not more than two percent (2%) fast.

e. Work Performed on Company's Facilities at Customer's Request

Whenever, at the request and for the benefit of the Customer, work is performed on the Company's facilities, including the relocation, or replacement of the Company's facilities, the Customer shall pay to the Company in advance of the Company undertaking the work the estimated total cost of such work. This cost shall be itemized by major categories and shall include the Company's overheads and shall be credited with the net value of any salvageable material. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the Customer.

Continued on Sheet 2-13

Terms and Conditions of Service Continued

Special Charges Continued

Reasonable notice of not less than three working days shall be given to the Company for all requested work except for the covering of the Company's lines. Notice of any request for the Company to cover its lines shall be given at least two days in advance. The Company will endeavor to comply with all timely requests, but work may be delayed because of demands on the Company's personnel and equipment.

If the cost, as calculated above, is $500 or less for covering the Company's distribution facilities no charge will be imposed. All costs in excess of $500 for covering the Company's distribution facilities shall be paid by the Customer, in advance of the Company undertaking the work. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the customer.

20. Refunds to Residential Customers

The Company may make a refund to residential customers by one of the following means: a credit to the Customer's bill, a prepaid card, or a check or electronic funds transfer (EFT).

The Company acting through its customer service representative shall fully address and resolve any customer complaints or disputes related to: (a) the accuracy of the names and last known addresses of the customer to receive prepaid cards; (b) the effective delivery and receipt of the prepaid cards; and (c) the amount of any refunds.

21. Alerts and Subscriptions

Kentucky Power offers an optional Mobile Alert Service for customers through which participating customers can elect to receive notifications from the Company via e-mail or text message. The Company provides billing and payment alerts and alerts relating to outages. These alerts are supplemental to standard communications from the Company and to the extent any discrepancies exist between the information contained in the mobile alerts and the information contained in standard communications from the Company, the information in the standard communications from the Company shall prevail.

Customers interested in receiving mobile alerts from Kentucky Power may sign up for the service through the Company's website at www.kentuckypower.com. The full terms and conditions of participating in the Kentucky Power Mobile Alert Service are included on the Company's website. Customers wishing to participate in Kentucky Power's Mobile Alert Service and to receive alerts via e-mail should add communications@kentuckypower-mailaep.com and communications@aep-email.com to the customer's email address book or spam filter to avoid alert communications from Kentucky Power being directed to spam. Customers are advised to contact their e-mail service provider for instructions on how to add addresses to an address book or spam filter if needed.

E-mail addresses from which alerts are sent through the Mobile Alert Service are used for sending e-mails only. Any e-mails sent to those addresses will not be received by the Company and the Company will not respond. Any electronic communication to the Company should be sent to Communications@kentuckypower-mail.com.

There is no charge from the Company for the Mobile Alert Service; however, message and data rates may apply. Customers are advised to verify message and data rates with their cellular and internet service providers.

Information regarding the types of alerts and the Mobile Alert Service in general are provided below.

Continued on Sheet 2-14

Terms and Conditions of Service Continued

Alerts and Subscriptions Continued

Billing and Payment Alerts

Billing and payment alerts provided through Kentucky Power's Mobile Alert Service are in addition to regular billing statements, payment notifications, disconnect notices, or other standard communications sent by Kentucky Power or its third party partners as required by law, regulation, or tariff filed by Kentucky Power or its subsidiaries. These alerts are not a replacement for any regular billing statement, payment notifications, disconnect notices, or other standard communications. In the event of a discrepancy between the information provided in a billing or payment alert provided through the Mobile Alert Service and the information provided in the Company's standard communication, the information in the standard communication shall prevail.

Kentucky Power shall not have any liability for any delay or failure to deliver a billing or payment alert or for any mistakes or errors in any billing or payment alert provided through the Mobile Alerts Service.

Outage Alerts

Kentucky Power provides alerts relating to system outages through its Mobile Alert Service. Outage alerts will be sent when the Company has evidence of an outage at a subscribed address. Due to variations in equipment from one area to another, it is possible that the accuracy of outage alerts will vary from one area to another. Recipients shall consider any outage related information as guidance and not as an absolute guarantee. Kentucky Power will send outage related notifications based upon available information and does not guarantee that the notifications will be without error.

Planned outages and short-duration outages will normally not generate an outage-related notification. During large-scale outage events, the frequency and timeliness of outage updates may be impacted.

Kentucky Power shall not have any liability for any delay or failure to deliver an outage-related notification.

General

Kentucky Power does not warrant or guarantee that alerts will be sent or received, and Kentucky Power shall not be responsible for any lost or misdirected messages.

Customers electing to participate in Kentucky Power's Mobile Alert Service authorize the Company to contact them via their elected communication method with transactional messages pertaining to the service. Participation in the Mobile Alert Service shall be considered as affirmative consent to receive the related messages should these messages ever be classified as commercial in nature.

Kentucky Power shall not have any liability under any theory of recovery, whether in contract or tort, for any loss or damages due to delay or failure to deliver an alert through the Mobile Alert Service. Without limiting the previous sentence, Kentucky Power disclaims any liability, expressed or implied, for indirect or consequential damages arising from a customer's subscription to Kentucky Power's Mobile Alert Service.

Customer agrees not to publish, copy, communicate to the public, edit, retransmit, or amend any data received as part of Kentucky Power's Mobile Alert Service. The data communicated via the Mobile Alert Service is provided for the participating customer's personal non-commercial use only and may not be used for any other purpose.

Continued on Sheet 2-15

Terms and Conditions of Service Continued

Alerts and Subscriptions Continued

Personal information and data ("Personal Data") provided by customers when using Kentucky Power's Mobile Alert Service will only be used by Kentucky Power and its suppliers and contractors for Mobile Alert Service-related purposes. Data other than Personal Data may be aggregated and used by the Company for the purpose of undertaking market research or in facilitating reviews, developments and improvements to Kentucky Power's Mobile Alert Service.

Customers participating in the Mobile Alert Service may discontinue a portion of or all alerts at any time by modifying their alert subscription or by unsubscribing entirely. Customers wishing to modify or unsubscribe from the Mobile Alert Service may do so at the Company's website: www.kentuckypower.com or by contacting Kentucky Power's Customer Operations Centers at 1-800-572-1113. Kentucky Power will process a request to unsubscribe from the Mobile Alert Service within ten days of receiving the request. Kentucky Power is authorized to send a communication to a customer requesting to unsubscribe from the Mobile Alert Service to confirm the request.

The terms and conditions the Company's Mobile Alert Service shall be governed by applicable state law.

Customers electing to participate in the Company's Mobile Alert Service agree to the terms and conditions of the service and further agree that the terms and conditions may be updated from time to time. The Company will provide customers participating in the Mobile Alert Service with updated terms and conditions as they become effective. Customers participating in the Mobile Alert Service must take affirmative action to withdraw from the service if the customer does not agree with any new or updated term or condition of service. Failure to withdraw after an updated term and condition is provided by the Company means that the customer accepts the new or updated terms and conditions.

Additional Terms and Conditions for E-mail Alerts
If a customer sends an email to Kentucky Power with questions or comments, Kentucky Power may use the customer's e-mail address and other personal information included in the correspondence in order to respond. If a customer provides the Company with an e-mail address in order to receive alerts, Kentucky Power may use that e-mail address to send the customer other types of information.

A customer may unsubscribe from receiving e-mail alerts by clicking the "Unsubscribe" link near the bottom of an e-mail alert.

Additional Terms and Conditions for Text Message Alerts
Customers may elect to receive text alerts through Kentucky Power's Mobile Alert Service. For text alerts, message and data rates may apply consistent with the customer's mobile phone service agreement. Kentucky Power assumes no responsibility for any service charges received from customer's mobile phone service providers for text alerts received through the Mobile Alert Service. Kentucky Power is not responsible for and will not be liable for any breach of the terms of an agreement between a customer electing to receive text alerts through the Mobile Alert System and that customer's mobile phone service provider or for any mistake that may arise in the billing process.

To receive text alerts from the Company through the Mobile Alert Service, the customer must be the owner or legitimate user of the mobile phone registered or have the express consent of the owner or legitimate user. Customers electing to receive text alerts from the Company through the Mobile Alert Service are responsible for providing and maintaining a mobile phone and ensuring connection to a mobile network capable of receiving the text alerts.

Continued on Sheet 2-16

Terms and Conditions of Service Continued

Alerts and Subscriptions Continued

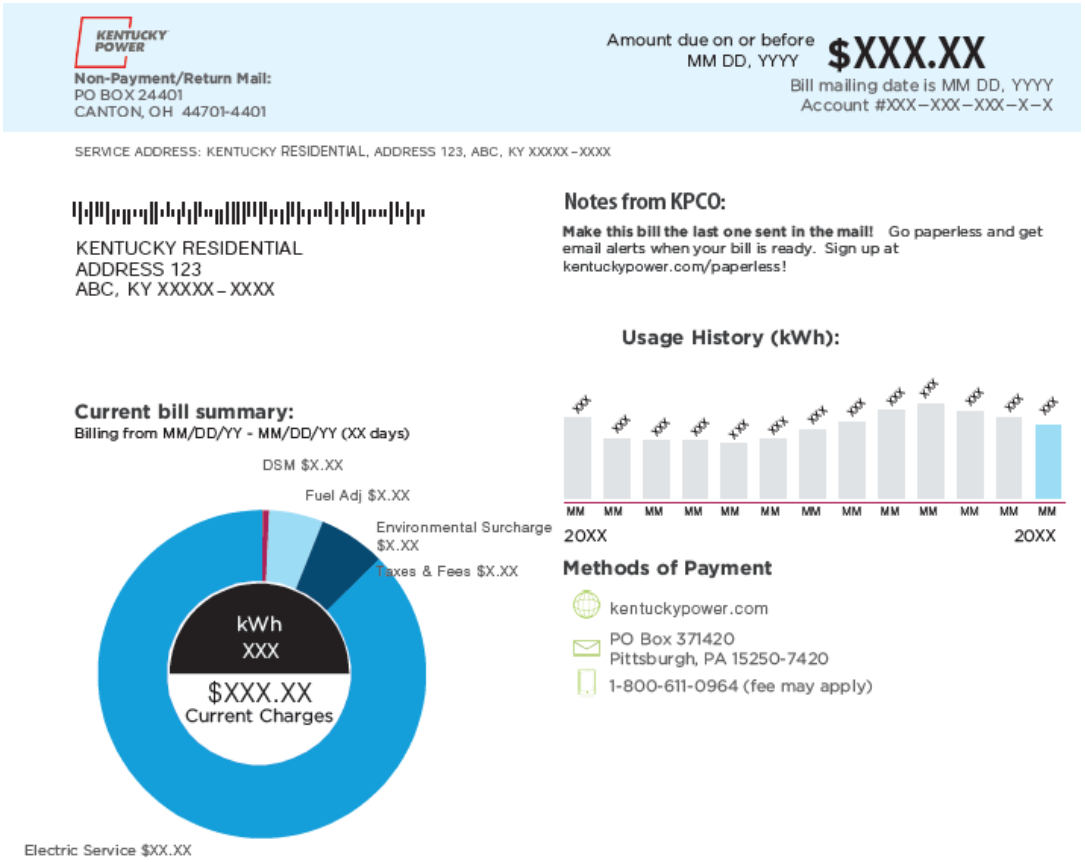
Customers electing to receive text alerts through the Mobile Alert Service acknowledge that the text alerts may, at any time, be adversely affected by problems with the mobile phone network including, without limitation, interference to the network coverage. Kentucky Power shall not be responsible or liable for any loss, damage, or expense incurred directly or indirectly by customers electing to receive text alerts through the Mobile Alert Service as a result of any difficulties experienced by any cellular phone service provider.

In the event a customer electing to receive text alerts through the Mobile Alert Service changes mobile phone service providers or telephone number, that customer is required to subscribe again to receive text alerts. If no alerts are sent or received for eighteen months, a customer's opt-in to that offering will expire. A customer must opt-in again to the program in order to receive alerts.

Kentucky Power may discontinue text alerts at any time. Customers electing to receive text alerts through the Mobile Alert Service will receive text alerts from 23711. Customers may unsubscribe from text alerts by texting STOP to 23711 and may obtain assistance via text by texting HELP to 23711.

Continued on Sheet 2-17

Terms and Conditions of Service Continued



Continued on Sheet 2-18

DATE OF ISSUE: August 29, 2025~~July 23, 2025~~
DATE EFFECTIVE: Services Rendered On And After March 1, 2026~~June 30, 2025~~
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Terms and Conditions of Service Continued

KENTUCKY POWER

Service Address:

KENTUCKY RESIDENTIAL
ADDRESS 123
ABC, KY XXXXX–XXXX
Account #XXX-XXX-XXX-X-X

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XXX.XX
Payment 02/07/22 - Thank You		-XXX.XX
Previous Balance Due	**$**	X.XX
Current KPCO Charges		
Tariff XXX - Residential Service XX/XX/XX		
Rate Billing	$	XXX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-XX.XX
Fuel Adj @ X.XXXXX Per kWh		XX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
DSM Adj @ X.XXXXX Per kWh		XX.XX
Residential Energy Assistance @ $X.XX		XX.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Renewable Power Option Rider		XX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Envrionmental Adj. X.XXXXX%		XX.XX
School Tax		XX.XX
City's Franchise Fee		XX.XX
State Sales Tax		XX.XX
Current Balance Due	**$**	**XXX.XX**
Homeserve Warranty Service	$	XX.XX

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
XXXXX	Actual	XXXXX	Actual	XXX	XXX kWh
Service Period XX/XX – XX/XX					Multiplier 1
Next scheduled read date should be between MM DD and MM DD .					

Notes from KPCO:

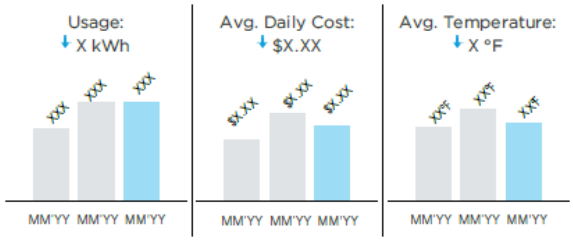
Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1–800–572–1113.

Homeserve USA is optional. Homeserve USA is not the same as KPCO and is not regulated by the KY Public Service Commission. A customer does not have to buy the Warranty Service in order to continue to receive quality regulated services from KPCO.

www.kyelectricalprotectionplan.com

Usage Details:

↑↓Values reflect changes between current month and previous month.



Total usage for the past 12 months: X,XXX kWh

Average (Avg.) monthly usage: XXX kWh

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
DATE EFFECTIVE: Services Rendered On And After March 1, 2026~~January 16, 2024~~
ISSUED BY: /s/ Tanner S. Wolffram~~Brian K. West~~
TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

KENTUCKY POWER

Service Address:

KENTUCKY RESIDENTIAL
ADDRESS 123
ABC, KY XXXXX–XXXX

Account #XXX-XXX-XXX-X-X

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XXX.XX
Payment 02/07/22 - Thank You		-XXX.XX
Previous Balance Due	**$**	**X.XX**
Current KPCO Charges		
Tariff XXX - Residential Service XX/XX/XX		
Rate Billing	$	XXX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-XX.XX
Fuel Adj @ X.XXXXX Per kWh		XX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
DSM Adj @ X.XXXXX Per kWh		XX.XX
Residential Energy Assistance @ $X.XX		XX.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Renewable Power Option Rider		XX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Generation Rider $X.XXXXX/kWh		XX.XX
Envrionmental Adj. X.XXXXX%		XX.XX
School Tax		XX.XX
City's Franchise Fee		XX.XX
State Sales Tax		XX.XX
Current Balance Due	**$**	**XXX.XX**
Homeserve Warranty Service	$	XX.XX

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
XXXXX	Actual	XXXXX	Actual	XXX	XXX kWh
Service Period XX/XX – XX/XX					Multiplier 1
Next scheduled read date should be between MM DD and MM DD .					

Notes from KPCO:

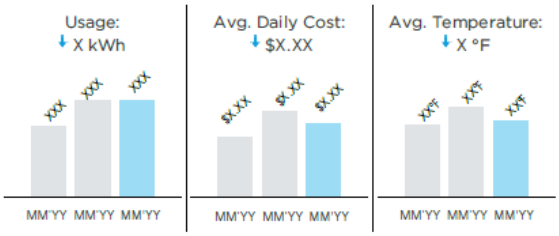
Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1–800–572–1113.

Homeserve USA is optional. Homeserve USA is not the same as KPCO and is not regulated by the KY Public Service Commission. A customer does not have to buy the Warranty Service in order to continue to receive quality regulated services from KPCO.

www.kyelectricalprotectionplan.com

Usage Details:

↑↓Values reflect changes between current month and previous month.



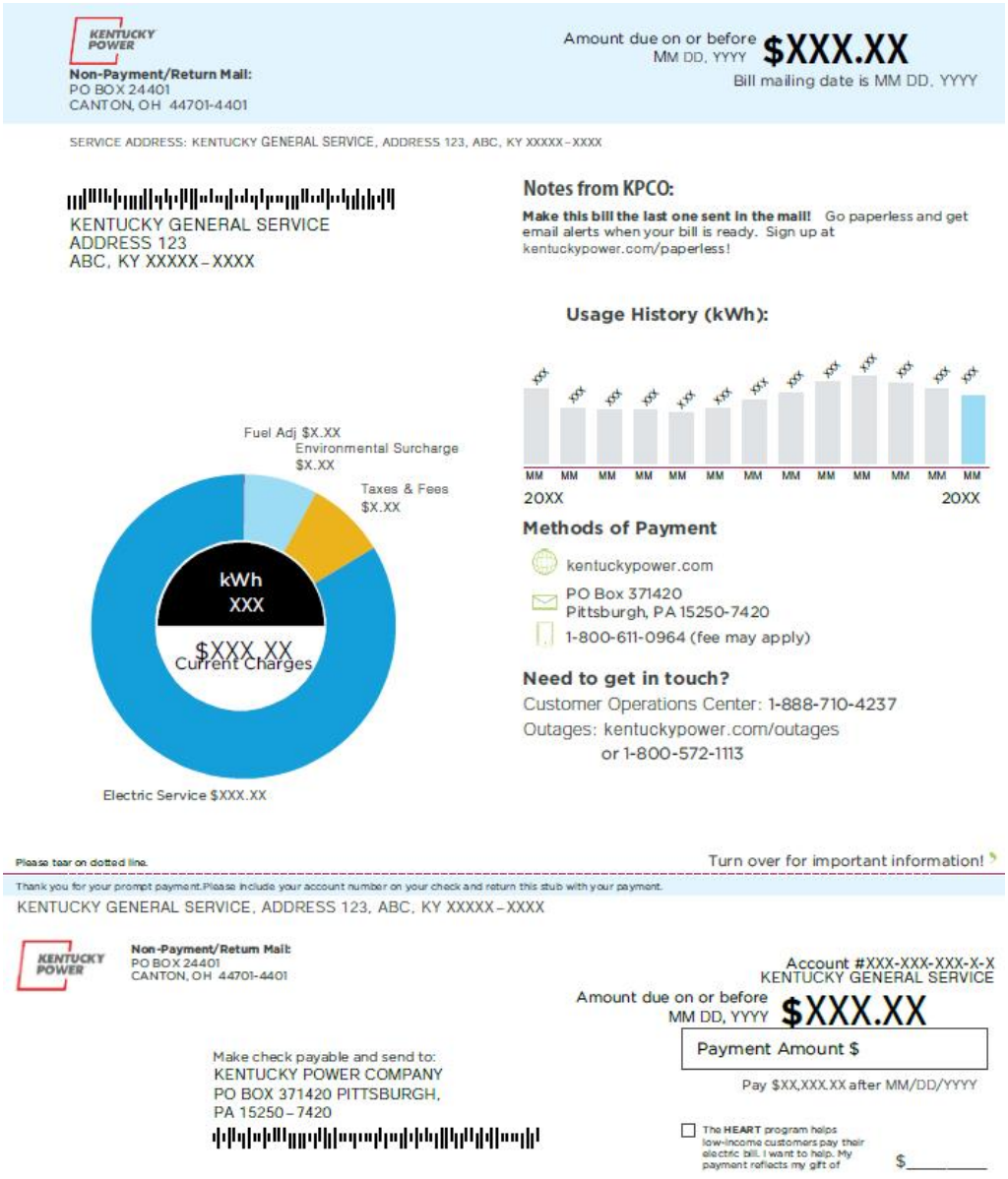
Total usage for the past 12 months: X,XXX kWh

Average (Avg.) monthly usage: XXX kWh

Continued on Sheet 2-19

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
DATE EFFECTIVE: Services Rendered On And After March 1, 2026~~January 16, 2024~~
ISSUED BY: /s/ Tanner S. Wolffram~~Brian K. West~~
TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Terms and Conditions of Service Continued



Continued on Sheet 2-20

Terms and Conditions of Service Continued

KENTUCKY POWER

Service Address:

KENTUCKY GENERAL SERVICE
ADDRESS 123
ABC, KY XXXXX – XXXX
Account #XXX-XXX-XXX-X-X

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XX.XX
Payment XX/XX/XX - Thank You		-XX.XX
Previous Balance Due	**$**	**X.XX**
Current KPCO Charges		
Tariff XXX - General Service XX/XX/XX		
Rate Billing	$	XX.XX
Demand Charge		XX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-XX.XX
Fuel Adj @ X.XXXXX Per kWh		XX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
DSM Adj @ X.XXXXX Per kWh		XX.XX
Kentucky Economic Development Surcharge @ $X.XX		XX.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Renewable Power Option Rider		XX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Envrionmental Adj. X.XXXXX%		XX.XX
School Tax		XX.XX
City's Franchise Fee		XX.XX
State Sales Tax		XX.XX
Current Balance Due	**$**	**XX.XX**

Meter Read Details:

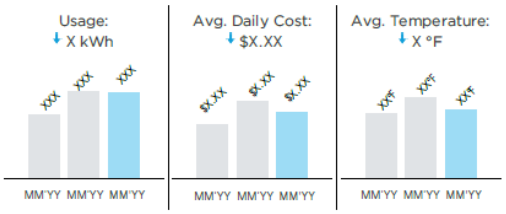
Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
XXX	Actual	XXX	Actual	XXX	XXX kWh
Service Period XX/XX - XX/XX					Multiplier 1
Next scheduled read date should be between MM DD and MM DD.					

Notes from KPCO:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Usage Details:

↑↓Values reflect changes between current month and previous month.



Total usage for the past 12 months: XXX kWh

Average (Avg.) monthly usage: XXX kWh

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
DATE EFFECTIVE: Services Rendered On And After March 1, 2026~~January 16, 2024~~
ISSUED BY: /s/ Tanner S. Wolffram~~Brian K. West~~
TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

KENTUCKY POWER

Service Address:

KENTUCKY GENERAL SERVICE
ADDRESS 123
ABC, KY XXXXX – XXXX

Account #XXX-XXX-XXX-X-X

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XX.XX
Payment XX/XX/XX - Thank You		-XX.XX
Previous Balance Due	**$**	**X.XX**
Current KPCO Charges		
Tariff XXX - General Service XX/XX/XX		
Rate Billing	$	XX.XX
Demand Charge		XX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-XX.XX
Fuel Adj @ X.XXXXX Per kWh		XX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
DSM Adj @ X.XXXXX Per kWh		XX.XX
Kentucky Economic Development Surcharge @ $X.XX		XX.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Renewable Power Option Rider		XX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Generation Rider $X.XXXXX/kWh		XX.XX
Envrionmental Adj. X.XXXXX%		XX.XX
School Tax		XX.XX
City's Franchise Fee		XX.XX
State Sales Tax		XX.XX
Current Balance Due	**$**	**XX.XX**

Meter Read Details:

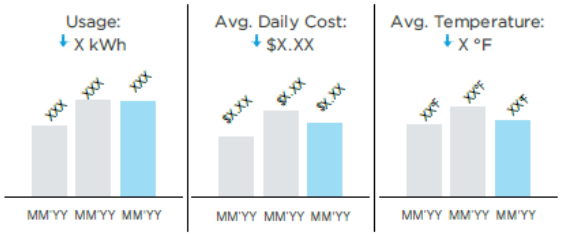
Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
XXX	Actual	XXX	Actual	XXX	XXX kWh
Service Period XX/XX - XX/XX					Multiplier 1
Next scheduled read date should be between MM DD and MM DD.					

Notes from KPCO:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Usage Details:

↑↓Values reflect changes between current month and previous month.



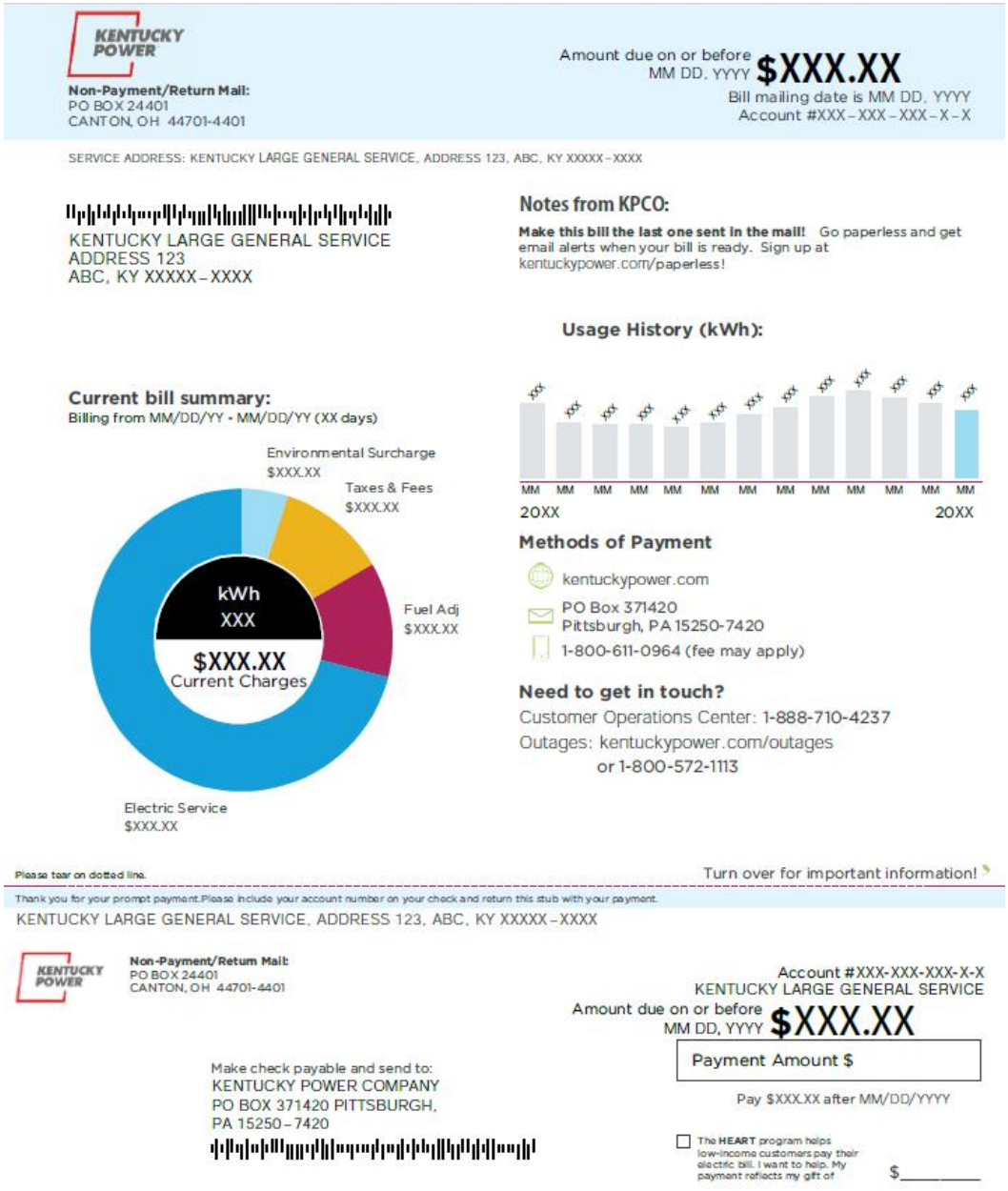
Total usage for the past 12 months: XXX kWh

Average (Avg.) monthly usage: XXX kWh

Continued on Sheet 2-21

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
DATE EFFECTIVE: Services Rendered On And After March 1, 2026~~January 16, 2024~~
ISSUED BY: /s/ Tanner S. Wolffram~~Brian K. West~~
TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Terms and Conditions of Service Continued



Continued on Sheet 2-22

Terms and Conditions of Service Continued

KENTUCKY POWER

Service Address:

KENTUCKY LARGE GENERAL SERVICE
ADDRESS 123
ABC, KY XXXXX – XXXX

Account #XXX-XXX-XXX-X-X

Billed Usage MM/YY				
Usage	Power Factor	Power Factor Constant	Meter Location Comp.	Billed Usage
XXX	-	-	-	XXXX kWh
XXX	-	-	-	XXX kW
XXX	-	-	-	XXX.XXX KVA

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XXX.XX
Payment XX/XX/XX - Thank You		-XXX.XX
Previous Balance Due	**$**	**XX.XX**
Current Charges		
Tariff XXX - Large General Service XX/XX/XX		
Rate Billing	$	XXX.XX
Demand Charge		-XXX.XX
Economic Development Rider - IBDD		-XXX.XX
Economic Development Rider - SBDD		-XXX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-XXX.XX
Fuel Adj @ X.XXXXX Per kWh		XXX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
DSM Adj @ X.XXXXX Per kWh		XXX.XX
Kentucky Economic Development Surcharge @ $X.XX		X.XX
Purchased Power Adj. $X.XXXXX/kWh		XXX.XX
Renewable Power Option Rider		XXX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Envrionmental Adj. X.XXXXX%		XXX.XX
School Tax		XXX.XX
City's Franchise Fee		XXX.XX
State Sales Tax		XXX.XX
Current Balance Due	**$**	**XXX.XX**

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
X	X	X.XXX	Actual	X	X kVAR
X	X	X.XXX	Actual	X.XXX	XXX.XX kW
XXXXX	Actual	XXXXX	Actual	XXX	XXX,XXX kWh
Service Period MM/DD - MM/DD				Multiplier XXX	
Next scheduled read date should be between MM DD and MM DD.					

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

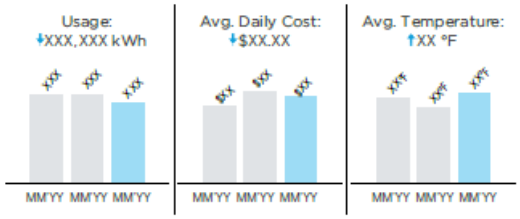
Notes from Kentucky Power:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/acclunt/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1 – 800 – 572 – 1113.

Due date does not apply to previous balance due.

Usage Details:

↑↓Values reflect changes between current month and previous month.



Total usage for the past 12 months: XXX kWh

Average (Avg.) monthly usage: XXX kWh

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
DATE EFFECTIVE: Services Rendered On And After March 1, 2026~~January 16, 2024~~
ISSUED BY: /s/ Tanner S. Wolffram~~Brian K. West~~
TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

KENTUCKY POWER

Service Address:

KENTUCKY LARGE GENERAL SERVICE

ADDRESS 123
ABC, KY XXXXX – XXXX

Account #XXX-XXX-XXX-X-X

Billed Usage MM/YY				
Usage	Power Factor	Power Factor Constant	Meter Location Comp.	Billed Usage
XXX	-	-	-	XXXX kWh
XXX	-	-	-	XXX kW
XXX	-	-	-	XXX.XXX KVA

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XXX.XX
Payment XX/XX/XX - Thank You		-XXX.XX
Previous Balance Due	$	XX.XX
Current Charges		
Tariff XXX - Large General Service XX/XX/XX		
Rate Billing	$	XXX.XX
Demand Charge		-XXX.XX
Economic Development Rider - IBDD		-XXX.XX
Economic Development Rider - SBDD		-XXX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-XXX.XX
Fuel Adj @ X.XXXXX Per kWh		XXX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
DSM Adj @ X.XXXXX Per kWh		XXX.XX
Kentucky Economic Development Surcharge @ $X.XX		X.XX
Purchased Power Adj. $X.XXXXX/kWh		XXX.XX
Renewable Power Option Rider		XXX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Generation Rider $X.XXXXX/kWh		XX.XX
Environmental Adj. X.XXXXX%		XXX.XX
School Tax		XXX.XX
City's Franchise Fee		XXX.XX
State Sales Tax		XXX.XX
Current Balance Due	$	XXX.XX

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
X	X	X.XXX	Actual	X	X kVAR
X	X	X.XXX	Actual	X.XXX	XXX.XX kW
XXXXX	Actual	XXXXX	Actual	XXX	XXX,XXX kWh
Service Period MM/DD - MM/DD				Multiplier XXX	
Next scheduled read date should be between MM DD and MM DD.					

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

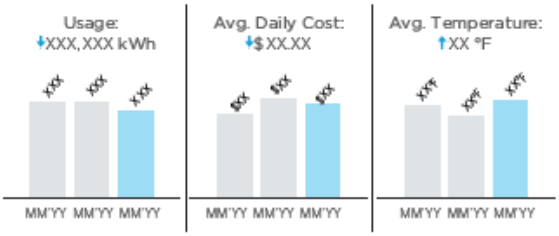
Notes from Kentucky Power:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/acclunt/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Due date does not apply to previous balance due.

Usage Details:

↑↓Values reflect changes between current month and previous month.



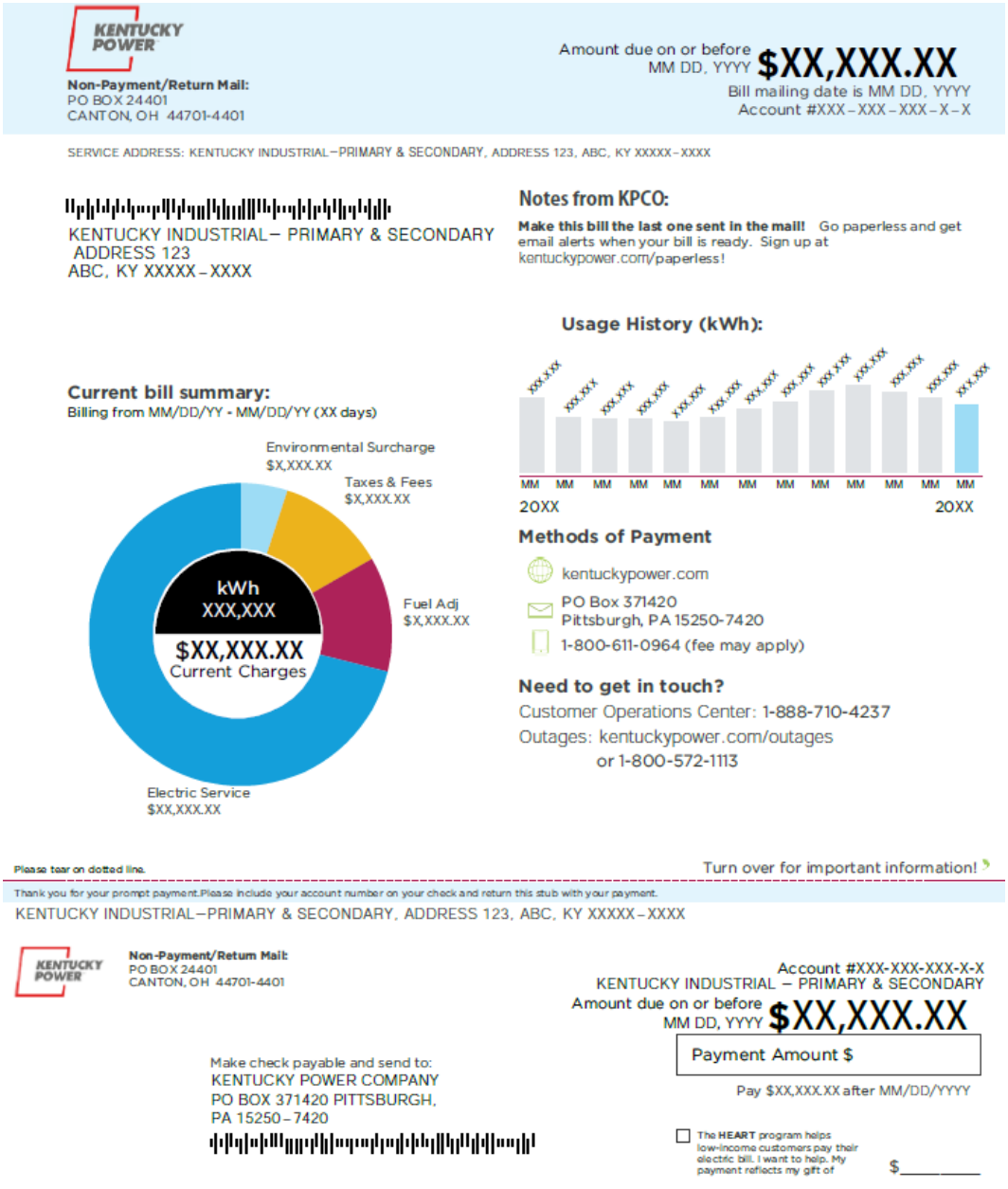
Total usage for the past 12 months: XXX kWh

Average (Avg.) monthly usage: XXX kWh

Continued on Sheet 2-23

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
DATE EFFECTIVE: Services Rendered On And After March 1, 2026~~January 16, 2024~~
ISSUED BY: /s/ Tanner S. Wolffram~~Brian K. West~~
TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Terms and Conditions of Service Continued



Continued on Sheet 2-24

Terms and Conditions of Service Continued

KENTUCKY POWER

Service Address:

KENTUCKY INDUSTRIAL–PRIMARY & SECONDARY

ADDRESS 123
ABC, KY XXXXX–XXXX

Account #XXX-XXX-XXX-X-X

Billed Usage MM/YY				
Usage	Power Factor	Power Factor Constant	Meter Location Comp.	Billed Usage
XXX.XXX	-	-	-	XXX.XXX kWh
XXX.XXX	-	-	-	XXX.XXX kW On-Pk
XXX.XXX	-	-	-	XXX.XXX kW Off-Pk
Contract Capacity = X,XXX.X			High Prev Demand = X,XXX.X On-Pk High Prev Demand = X,XXX.X Off-Pk	

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XX,XXX.XX
Payment XX/XX/XX - Thank You		-XX,XXX.XX
Previous Balance Due	**$**	**XX.XX**
Current Charges		
Tariff XXX - Industrial General Service XX/XX/XX		
Rate Billing	$	XX,XXX.XX
Demand Charge		-X,XXX.XX
Economic Development Rider - IBDD		-X,XXX.XX
Economic Development Rider - SBDD		-X,XXX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-X,XXX.XX
Fuel Adj @ X.XXXXX Per kWh		X,XXX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
Kentucky Economic Development Surcharge @ $X.XX		X.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Purchased Power Adj. $X.XXXXX/kW		X,XXX.XX
Renewable Power Option Rider		X,XXX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Environmental Adj. X.XXXXX%		X,XXX.XX
School Tax		X,XXX.XX
City's Franchise Fee		X,XXX.XX
State Sales Tax		X,XXX.XX
Total Balance Due	**$**	**XX,XXX.XX**

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
X	X	X.XXX	Actual	X	X kVAR
X	X	X.XXX	Actual	X.XXX	XXX.XX kW On-Pk
XXXXX	Actual	XXXXX	Actual	XXX	XXX,XXX kWh
X	X	X.XXX	Actual	X.XX	XXX.X kW Off-Pk
X	X	X.XXX	Actual	X.XXX	XXX.XX kVAR
Service Period MM/DD - MM/DD				Multiplier XXX	
Next scheduled read date should be between MM/DD and MM/DD					

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

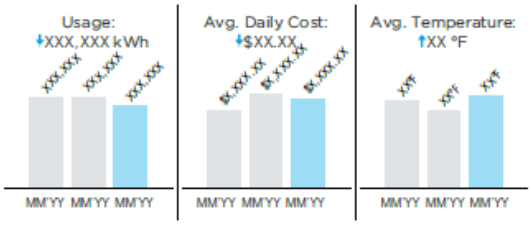
Notes from Kentucky Power:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Due date does not apply to previous balance due.

Usage Details:

↑↓Values reflect changes between current month and previous month.



Total usage for the past 12 months: X,XXX,XXX kWh

Average (Avg.) monthly usage: XXX,XXX kWh

KENTUCKY POWER

Service Address:

KENTUCKY INDUSTRIAL–PRIMARY & SECONDARY

ADDRESS 123
ABC, KY XXXXX–XXXX

Account #XXX-XXX-XXX-X-X

Billed Usage MM/YY				
Usage	Power Factor	Power Factor Constant	Meter Location Comp.	Billed Usage
XXX,XXX	-	-	-	XXX,XXX kWh
XXX.XXX	-	-	-	XXX.XXX kW On-Pk
XXX.XXX	-	-	-	XXX.XXX kW Off-Pk
Contract Capacity = X,XXX.X				High Prev Demand = X,XXX.X On-Pk
				High Prev Demand = X,XXX.X Off-Pk

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XX,XXX.XX
Payment XX/XX/XX - Thank You		-XX,XXX.XX
Previous Balance Due	**$**	**XX.XX**
Current Charges		
Tariff XXX - Industrial General Service XX/XX/XX		
Rate Billing	$	XX,XXX.XX
Demand Charge		-X,XXX.XX
Economic Development Rider - IBDD		-X,XXX.XX
Economic Development Rider - SBDD		-X,XXX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-X,XXX.XX
Fuel Adj @ X.XXXXX Per kWh		X,XXX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
Kentucky Economic Development Surcharge @ $X.XX		X.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Purchased Power Adj. $X.XXXXX/kW		X,XXX.XX
Renewable Power Option Rider		X,XXX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Generation Rider $X.XXXXX/kW		XX.XX
City's Franchise Fee		X,XXX.XX
State Sales Tax		X,XXX.XX
Total Balance Due	**$**	**XX,XXX.XX**

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
X	X	X.XXX	Actual	X	X kVAR
X	X	X.XXX	Actual	X.XXX	XXX.XX kW On-Pk
XXXXX	Actual	XXXXX	Actual	XXX	XXX,XXX kWh
X	X	X.XXX	Actual	X.XX	XXX.X kW Off-Pk
X	X	X.XXX	Actual	X.XXX	XXX.XX kVAR
Service Period MM/DD - MM/DD					Multiplier XXX
Next scheduled read date should be between MM DD and MM DD .					

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

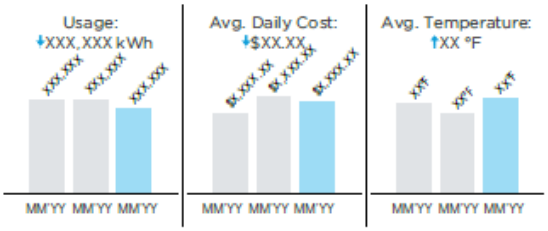
Notes from Kentucky Power:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/acclunt/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Due date does not apply to previous balance due.

Usage Details:

↑↓Values reflect changes between current month and previous month.

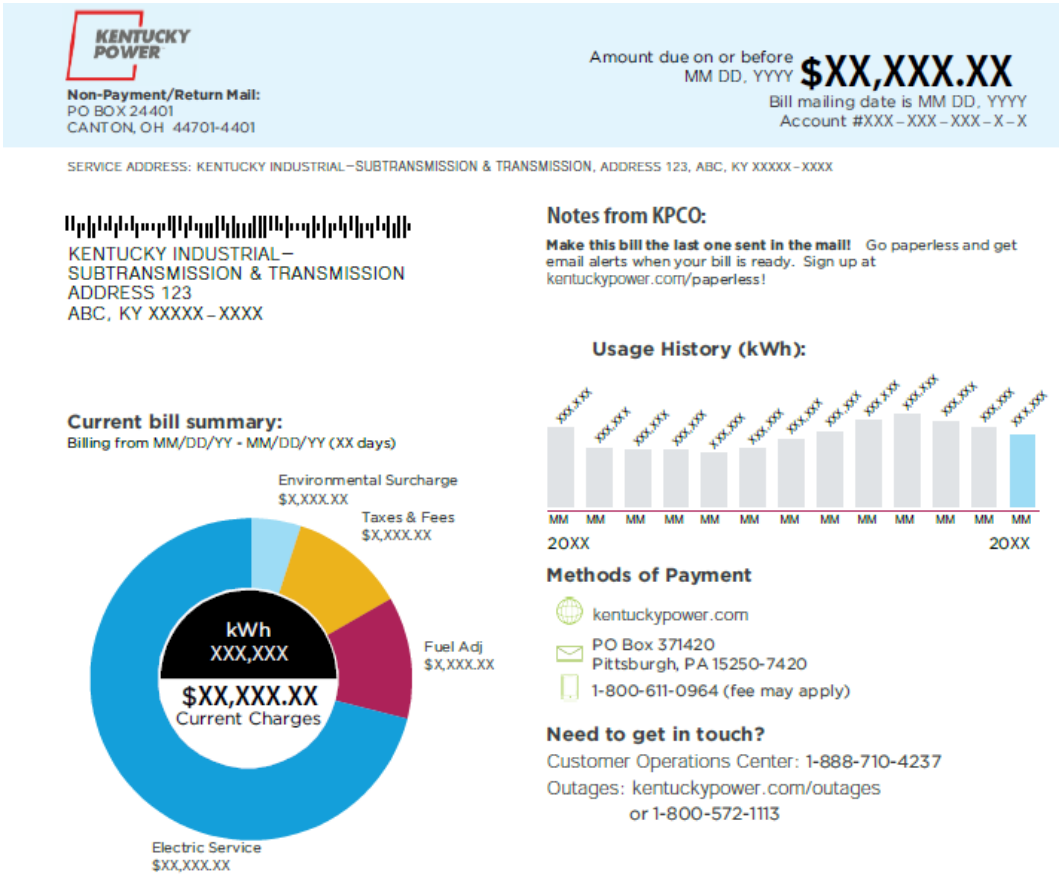


Total usage for the past 12 months: X,XXX,XXX kWh

Average (Avg.) monthly usage: XXX,XXX kWh

Continued on Sheet 2-25

Terms and Conditions of Service Continued



Continued on Sheet 2-26

Terms and Conditions of Service Continued

KENTUCKY POWER

Service Address:

KENTUCKY INDUSTRIAL–
SUBTRANSMISSION AND TRANSMISSION
ADDRESS 123
ABC, KY XXXXX–XXXX

Account #XXX-XXX-XXX-X-X

Billed Usage MM/YY				
Usage	Power Factor	Power Factor Constant	Meter Location Comp.	Billed Usage
XXX.XXX	-	-	-	XXX.XXX kWh
XXX.XXX	-	-	-	XXX.XXX kW On-Pk
XXX.XXX	-	-	-	XXX.XXX kW Off-Pk
Contract Capacity = X,XXX.X				High Prev Demand = X,XXX.X On-Pk High Prev Demand = X,XXX.X Off-Pk

Previous Charges		
Total Amount Due At Last Billing	$	XX,XXX.XX
Payment XX/XX/XX - Thank You		-XX,XXX.XX
Previous Balance Due	**$**	**XX.XX**

Current Charges		
Tariff XXX - Industrial General Service XX/XX/XX		
Rate Billing	$	XX,XXX.XX
Demand Charge		-X,XXX.XX
Economic Development Rider - IBDD		-X,XXX.XX
Economic Development Rider - SBDD		-X,XXX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-X,XXX.XX
Fuel Adj @ X.XXXXX Per kWh		X,XXX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
Kentucky Economic Development Surcharge @ $X.XX		X.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Purchased Power Adj. $X.XXXXX/kW		X,XXX.XX
Renewable Power Option Rider		X,XXX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Envrionmental Adj. X.XXXXX%		X,XXX.XX
School Tax		X,XXX.XX
City's Franchise Fee		X,XXX.XX
State Sales Tax		X,XXX.XX
Total Balance Due	**$**	**XX,XXX.XX**

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
X	X	X.XXX	Actual	X	X kVAR
X	X	X.XXX	Actual	X.XXX	XXX.XX kW On-Pk
XXXXX	Actual	XXXXX	Actual	XXX	XXX,XXX kWh
X	X	X.XXX	Actual	X.XX	XXX.X kW Off-Pk
X	X	X.XXX	Actual	X.XXX	XXX.XX kVAR
Service Period MM/DD - MM/DD				Multiplier XXX	
Next scheduled read date should be between MM/DD and MM/DD					

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

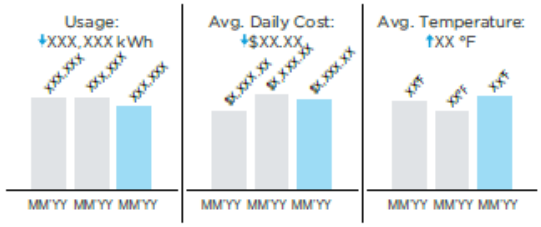
Notes from Kentucky Power:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1–800–572–1113.

Due date does not apply to previous balance due.

Usage Details:

↑↓Values reflect changes between current month and previous month.



Total usage for the past 12 months: X,XXX,XXX kWh

Average (Avg.) monthly usage: XXX,XXX kWh

KENTUCKY POWER

Service Address:

KENTUCKY INDUSTRIAL–
SUBTRANSMISSION AND TRANSMISSION
ADDRESS 123
ABC, KY XXXXX–XXXX

Account #XXX-XXX-XXX-X-X

Billed Usage MM/YY				
Usage	Power Factor	Power Factor Constant	Meter Location Comp.	Billed Usage
XXX.XXX	-	-	-	XXX.XXX kWh
XXX.XXX	-	-	-	XXX.XXX kW On-Pk
XXX.XXX	-	-	-	XXX.XXX kW Off-Pk
Contract Capacity = X,XXX.X				High Prev Demand = X,XXX.X On-Pk
				High Prev Demand = X,XXX.X Off-Pk

Previous Charges		
Total Amount Due At Last Billing	$	XX,XXX.XX
Payment XX/XX/XX - Thank You		-XX,XXX.XX
Previous Balance Due	**$**	XX.XX
Current Charges		

Tariff XXX - Industrial General Service XX/XX/XX		
Rate Billing	$	XX,XXX.XX
Demand Charge		-X,XXX.XX
Economic Development Rider - IBDD		-X,XXX.XX
Economic Development Rider - SBDD		-X,XXX.XX
Federal Tax Cut @ X.XXXXX- Per kWh		-X,XXX.XX
Fuel Adj @ X.XXXXX Per kWh		X,XXX.XX
Fuel Adjustment Credit @ X.XXXXX Per kWh		-XX.XX
Kentucky Economic Development Surcharge @ $X.XX		X.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Purchased Power Adj. $X.XXXXX/kW		X,XXX.XX
Renewable Power Option Rider		X,XXX.XX
Securitized Surcharge Rider X.XXXXX%		XX.XX
Generation Rider $X.XXXXX/kW		XX.XX
City's Franchise Fee		X,XXX.XX
State Sales Tax		X,XXX.XX
Total Balance Due	**$**	**XX,XXX.XX**

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
X	X	X.XXX	Actual	X	X kVAR
X	X	X.XXX	Actual	X.XXX	XXX.XX kW On-Pk
XXXXX	Actual	XXXXX	Actual	XXX	XXX,XXX kWh
X	X	X.XXX	Actual	X.XX	XXX.X kW Off-Pk
X	X	X.XXX	Actual	X.XXX	XXX.XX kVAR
Service Period MM/DD - MM/DD					Multiplier XXX
Next scheduled read date should be between MM DD and MM DD .					

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

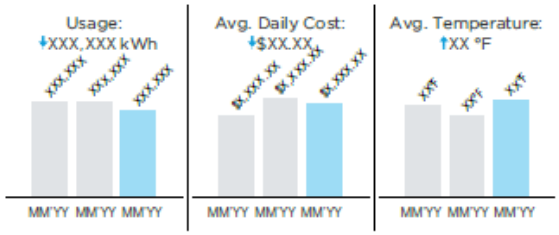
Notes from Kentucky Power:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1–800–572–1113.

Due date does not apply to previous balance due.

Usage Details:

↑↓Values reflect changes between current month and previous month.



Total usage for the past 12 months: X,XXX,XXX kWh

Average (Avg.) monthly usage: XXX,XXX kWh

Capacity and Energy Control Program

Introduction

Kentucky Power Company's Capacity and Energy Control Program outlines the procedures the Company will follow in the event of an emergency that threatens the continued reliable operation of bulk power supply system. Notwithstanding any provisions of this Capacity and Energy Control Program, the Company shall have the right to take whatever steps, with or without notice and without liability on Company's part, that Company believes necessary, in whatever order consistent with good utility practices and not on an unduly discriminatory basis, to preserve system integrity and to prevent the collapse of Company's electric system or interconnected electric network or to restore service following an outage. Such actions will be taken giving priority to maintaining service to Company's retail and full requirements customers relative to other sales whenever feasible and as allowed by law. The Company's Capacity and Energy Control Program consists of three sets of procedures:

I. Procedures During Abnormal System Frequency
II. Capacity Deficiency Program
III. Energy Emergency Control Program

Specific details regarding the Company's Capacity and Energy Control Program are included in the Company's Emergency Operating Plan ("EOP"). A copy of the Company's current EOP is on file with the Kentucky Public Service Commission in Administrative Case No. 345. Where this tariff diverts from the Company's EOP, the EOP Plan shall govern.

I. AEP/PJM Procedures During Abnormal System Frequency (EOP Section IV)

a. Purpose

Precautionary procedures are required to meet emergency conditions such as system separation and operation at subnormal frequency. In addition, the coordination of these emergency procedures with neighboring companies is essential. The AEP/PJM program described below provides procedures for reducing the consumption of electric energy on the Company's system in the event of a period of abnormal system frequency.

b. AEP/PJM Procedures

From 59.8 – 60.2 Hz, to the extent practicable, the Company will utilize all operating and emergency reserves. The manner of utilization of these reserves depends on the behavior of the System during the emergency.

For rapid frequency decline, the Company will utilize capacity that is on-line and automatically responsive to frequency (spinning reserve) and such measures as interconnection assistance and automatic load reductions to arrest the decline in frequency.

If the frequency decline is gradual, the Generation/Production Optimization Group, particularly in the deficient area, will invoke non-automatic procedures involving operating and emergency reserves. These efforts will continue until the frequency decline is arrested or until automatic load-shedding devices operate at subnormal frequencies. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities. At 59.75 Hz, the Company will suspend Automatic Generation Control (AGC) and notify Interruptible Customers to drop load.

Continued on Sheet 3-2

Capacity and Energy Control Program Continued

If at any time the decline in area frequency is arrested below 59.5 Hz, the Company will evaluate whether the area should manually shed an additional 5% of its initial load. If, after five minutes, shedding 5% of load has not returned the area frequency to 59.5 Hz or above, the area shall manually shed an additional 5% of its remaining load and continue to repeat in five-minute intervals until 59.5 Hz is reached. These steps must be completed within the time constraints imposed upon the operation of generating units that are discussed in the EOP subsection titled, "Isolation of Coal-fired Generating Units."

Automatic Load Shedding Program details are located in Section IV of the Company's EOP.

II. Capacity Deficiency Program (EOP Section III)

a. Purpose
The purpose of the Capacity Deficiency Program is to provide a plan for full utilization of emergency capacity resources and for orderly reduction in the aggregate customer demand on the American Electric Power (AEP) East/PJM Eastern System in the event of a capacity deficiency. A capacity deficiency is a shortage of generation versus load and can be caused by generating unit outages and/or extreme internal load requirements.

b. AEP East/PJM Procedures
There are three general levels of emergency actions for capacity deficiencies:

- Alerts - issued in advance of the operating day for elevated awareness and to give time for advanced preparations.
- Warnings - issued real time, typically preceding, and with an estimated time/window for a potential future action.
- Actions - issued real time and requires PJM and/or Member response. PJM actions are consistent with NERC and RFC EOP standards.

The Company may also issue an Advisory, one or more days in advance of the operating day during which a capacity deficiency may occur, that are general in nature and are for elevated awareness only. No preparations or actions are required in response to an Advisory.

Alerts

Voluntary Customer Load Curtailment Alert
The purpose of the Voluntary Customer Load Curtailment Alert is to alert members of the probable future need to implement a voluntary customer load curtailment. It is implemented whenever the estimated operating reserve capacity indicates a probable future need for voluntary customer load curtailment.

Real Time Emergency Procedures (Warnings and Actions)

Warnings
Warnings are issued in real time during present operations to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM RTO. Generally, a warning precedes an associated action. The intent of warnings is to keep all affected system personnel aware of the forecast and/or actual status of the PJM RTO.

Continued on Sheet 3-3

Capacity and Energy Control Program Continued

Actions
The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain system reliability. These measures involve:

- loading generation that is restricted for reasons other than cost
- recalling non-capacity backed off-system sales
- purchasing emergency energy from participants / surrounding pools
- load relief measures

The Company's EOP includes a nine-step warning and action procedure during capacity deficiency conditions.

c. Priority Levels
For the purpose of these capacity deficiency procedures, the following Priority Levels for loads have been established:

I. Essential Health and Safety Uses – to be given special consideration in these procedures shall, insofar as the situation permits, include the following types of use:

a. Hospitals, which shall be limited to institutions providing medical care to patients.

b. Life Support Equipment, which shall be limited to kidney machines, respirators, and similar equipment used to sustain the life of a person.

c. Police Stations and Government Detention Institutions, which shall be limited to essential uses required for police activities and the operation of facilities used for the detention of persons.

d. Fire Stations, which shall be limited to facilities housing mobile fire-fighting apparatus.

e. Communication Services, which shall be limited to essential uses required for telephone, telegraph, television, radio and newspaper operations, and operation of state and local emergency services.

f. Water and Sewage Services, which shall be limited to essential uses required for the supply of water to a community, flood pumping and sewage disposal.

g. Transportation and Defense-related Services, which shall be limited to essential uses required for the operation, guidance control and navigation of air, rail and mass transit systems, including those uses essential to the national defense and operation of state and local emergency services. These uses shall include essential services such as street, highway and signal-lighting.

Although, when practical, these types of uses will be given special consideration when implementing the manual load- shedding provisions of this program, any customer may be affected by rotating or unplanned outages and should install emergency generation equipment if continuity of service is essential. Where the emergency is system-wide in nature, consideration will be given to the use of rotating outages as operationally practicable. In case of customers supplied from two utility sources, only one source will be given special consideration. Also, any other customers who, in their opinion, have critical equipment should install emergency generation equipment.

Continued on Sheet 3-4

Capacity and Energy Control Program Continued

Priority Levels Continued

Company maintains lists of customers with life support equipment and other critical needs for the purpose of curtailments and service restorations. Company, lacking knowledge of changes that may occur at any time in Customer's equipment, operation, and backup resources, does not assume the responsibility of identifying customers with priority needs. It shall, therefore, be Customer's responsibility to notify Company if Customer has critical needs.

II. Critical Commercial and Industrial Uses – Except as described in Section C.III below, these uses shall include commercial or industrial operations requiring regimented shutdowns to prevent conditions hazardous to the general population, and to energy utilities and their support facilities critical to the production, transportation, and distribution of service to the general population. Company shall maintain a list of such customers for the purpose of curtailments and service restoration.

III. Residential Use – Residential use during certain weather conditions (for example severe winter weather) will receive precedence over critical commercial and industrial uses. The availability of Company service personnel and the circumstances associated with the outage will also be considered in the restoration of service.

IV. Non-critical commercial and industrial uses.

V. Nonessential Uses – The following and similar types of uses of electric energy shall be considered nonessential for all customers:

a. Outdoor flood and advertising lighting, except for the minimum level to protect life and property, and a single illuminated sign identifying commercial facilities when operating after dark.

b. General interior lighting levels greater than minimum functional levels.

c. Show-window and display lighting.

d. Parking lot lighting above minimum functional levels.

e. Energy use to lower the temperature below 78 degrees during operation of cooling equipment and above 65 degrees during operation of heating equipment.

f. Elevator and escalator use in excess of the minimum necessary for non-peak hours of use.

g. Energy use greater than that which is the minimum required for lighting, heating, or cooling of commercial or industrial facilities for maintenance cleaning or business-related activities during non-business hours.

Non-jurisdictional customers will be treated in a manner consistent with the curtailment procedures contained in the service agreement between the parties or the applicable tariff.

Continued on Sheet 3-5

Capacity and Energy Control Program Continued

d. Curtailment Procedures

In the event Company's load exceeds internal generation, transmission, or distribution capacity, or other system disturbances exist, and internal efforts have failed to alleviate the problem, including emergency energy purchases, the following steps may be taken, individually or in combination, in the order necessary as time permits:

1. Customers having their own internal generation capacity will be curtailed, and customers on interruptible contracts will be curtailed for the maximum hours and load allowable under their contract. Nothing in this procedure shall limit Company's rights under the Contract Service – Interruptible Power Tariff or the Alternate Feed Service Rider.

2. Power output will be maximized at Company's generating units.

3. Company use of energy at its generating stations will be reduced to a minimum.

4. Company's use of electric energy in the operation of its offices and other facilities will be reduced to a minimum.

5. The Kentucky Public Service Commission will be advised of the situation.

6. An appeal will be made to customers through the news media and/or personal contact to voluntarily curtail as much load as possible. The appeal will emphasize the defined priority levels as set forth above.

7. Customers will be advised through the use of the news media and personal contact that load interruption is imminent.

8. Implement procedures for interruption of selected distribution circuits.

e. Service Restoration Procedures

Where practical, priority uses will be considered in restoring service and service will be restored in the order I through V as defined under Priority Levels described above. However, because of the varieties of unpredictable circumstances which may exist or precipitate outages, it may be necessary to balance specific individual needs with infrastructure needs that affect a larger population. When practical, Company will attempt to provide estimates of repair times on its website to aid customers in assessing the need for alternative power sources and temporary relocations.

III. Energy Emergency Control Program (EOP Section V)

a. Introduction

The purpose of this plan is to provide for the reduction of the consumption of electric energy on the American Electric Power Company System in the event of a severe coal fuel shortage, such as might result from a general strike, or severe weather.

b. Procedures

In the event of a potential severe coal shortage, such as one resulting from a general coal strike, the following steps will be implemented. These steps will be carried out to the extent permitted by contractual commitments or by order of the regulatory authorities having jurisdiction. For further information, see EOP Section V.

With regard to mandatory curtailments, the Company proposes to monitor compliance after the fact. A customer exceeding his electric allotment would be warned to curtail his usage or face, upon continuing noncompliance and upon one day's actual written notice, disconnection of electric service for the duration of the energy emergency.

Standard Nominal Voltages

The voltage available to any individual customer shall depend upon the voltage of the Company's lines serving the area in which customer is provided service.

Electric service provided under the Company's rate schedules will be 60 hertz alternating current delivered from various load centers at nominal voltages and phases as available in a given location as follows:

Secondary Distribution Voltages

Residential Service

Single phase 120/240 volts three wire or 120/208 volts three wire on network system.

General Service - All Except Residential

Single-phase 120/240 volts three wire or 120/208 volts three wire on network system. Three-phase 120/208 volts four wire on network system, 120/240 volts four wire, 240 volts three wire, 480 volts three wire and 277/480 volts four wire, Single-phase 480 volts two wire, and Single-phase 240/480 volts three wire.

Primary Distribution Voltages

The Company's primary distribution voltage levels at load centers are 2,400; 4,160Y; 7,200; 12,470Y; 19,900 and 34,500Y.

Subtransmission Line Voltages

The Company's sub transmission voltage levels are 34,500; 46,000; and 69,000.

Transmission Line Voltages

The Company's transmission voltage levels are 138,000; 161,000; 345,000; and 765,000.

Tariff R.S.
(Residential Service)

Availability of Service
Available for full domestic electric service through 1 (one) meter to individual residential customers including rural residential customers engaged principally in agricultural pursuits.

Rate *(Tariff Codes 015, 017, 022)*

Service Charge*	~~$20.00~~	~~per month~~
Tier 1 (0-2,000 kWh)	$26.00	per month
Tier 2 (over 2,000 kWh)	$40.00	per month
Energy Charge**	~~12.785¢~~	~~per kWh~~
Block 1 (0-600 kWh)	15.750¢	per kWh
Block 2 (over 600 kWh)	12.606¢	per kWh

*Customers will only be charged either the Tier 1 or Tier 2 service charge based on the customer's total energy usage for the billing period.

** Customers will be charged the Block 1 energy charge for all usage up to 600 kWh and the Block 2 energy charge for all usage above 600 kWh for the billing period.

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 33~~32~~
Decommissioning Rider	Sheet No. 34~~33~~
Securitized Surcharge Rider	Sheet No. 35~~34~~
Federal Tax Cut Tariff	Sheet No. 36~~35~~
City's Franchise Fee	Sheet No. 37~~36~~
School Tax	Sheet No. 38~~37~~

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5~~2 4~~. Residential customers are not subject to a delayed payment charge.

Volunteer Departments *(Tariff Code 024)*
Volunteer Fire Departments may qualify pursuant to KRS 278.172 for this tariff but will be required to provide a completed Form 990 and update it annually.

Continued on Sheet 5-2

DATE OF ISSUE: ~~April 4, 2025~~ August 29, 2025
DATE EFFECTIVE: Services Rendered On And After ~~February 21, 2025~~March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated ~~March 17, 2025~~ XXXX XX, XXXX

Tariff R.S. Continued
(Residential Service)

Storage Water Heating Provision
This provision is withdrawn except for the present installations of current customers receiving service hereunder at premises served prior to April 1, 1997.

If the customer installs a Company approved storage water heating system which consumes electrical energy only during off-peak hours as specified by the Company and stores hot water for use during on-peak hours, the following shall apply:

Tariff Code			
012	For Minimum Capacity of 80 gallons, the last 300 kWh of use in any month shall be billed at	9.317¢	per kWh
013	For Minimum Capacity of 100 gallons, the last 400 kWh of use in any month shall be billed at	9.317¢	per kWh
014	For Minimum Capacity of 120 gallons or greater, the last 500 kWh of use in any month shall be billed at	9.317¢	per kWh

These provisions, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For purpose of this provision, the on-peak billing period is defined as 7:00A.M. to 9:00P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00PM to 7:00AM for all weekdays and all hours of Saturday and Sunday.

The Company reserves the right to inspect at all reasonable times the storage water heating system and devices which qualify the residence for service under the storage water heater provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgment the availability conditions of this provision are being violated, it may discontinue billing the Customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge, and the adjustment clauses as stated in the Adjustment Clauses section.

Load Management Water-Heating Provision *(Tariff Code 011)*
For residential customers who install a load management water-heating system which consumes electrical energy during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 kWh of use in any month shall be billed at 9.317¢ per kWh.

This provision, however, shall in no event apply to the first 200 kWh used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For the purpose of this provision, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Continued on Sheet 5-3

Tariff R.S. Continued
(Residential Service)

Load Management Water Heating Provision Continued

The Company reserves the right to inspect at all reasonable times the load management water-heating system(s) and devices which qualify the residence for service under the Load Management Water-Heating Provision. If the Company finds that, in its sole judgment, the availability conditions of this provision are being violated; it may discontinue billing the Customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge, and the adjustment clauses as stated in the Adjustment Clauses section.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This service is available to rural domestic customers engaged principally in agricultural pursuits where service is taken through one meter for residential purposes as well as for the usual farm uses outside the home, but it is not extended to operations of a commercial nature or operations such as processing, preparing or distributing products not raised or produced on the farm, unless such operation is incidental to the usual residential and farm uses.

The Company shall have the option of reading meters monthly or bimonthly and rendering bills accordingly. When bills are rendered bimonthly, the minimum charge and the quantity of KWH in each block of the rates shall be multiplied by two.

Pursuant to 807 KAR 5:041, Section 11, paragraph (1), of Public Service Commission Regulations, the Company will make an extension of 1,000 feet or less to its existing distribution line without charge for a prospective permanent residential customer served under this R.S.Tariff. Pursuant to 807 KAR 5:041 Section 12 extensions of up to 150 feet for a mobile home are provided without charge.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP-I or by special agreement.

Continued on Sheet 5-4

Tariff R.S.-L.M.-T.O.D.
(Residential Service Load Management Time of Day)

Availability of Service
Available to customers eligible for Tariff R.S. (Residential Service) who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours.

Households eligible to be served under this tariff shall be metered through a multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods.

Rate *(Tariff Codes 028, 030, 032, 034)*

Service Charge	$~~23.00~~ 29.00	per month
Energy Charge		
All kWh used during on-peak billing period	~~17.335~~ 19.962¢	per kWh
All kWh used during off-peak billing period	9.317¢	per kWh

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Conservation and Load Management Credit
For the combination of an approved electric thermal storage space heating system and water heater, both of which are designed to consume electrical energy only between the hours of 9:00P.M. and 7:00A.M. for all days of the week, each residence will be credited 0.745¢ per kWh for all energy used during the off-peak billing period, for a total of 60 monthly billing periods following the installation and use of these devices in such residence.

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 33~~32~~
Decommissioning Rider	Sheet No. 34~~33~~
Securitized Surcharge Rider	Sheet No. 35~~34~~
Federal Tax Cut Tariff	Sheet No. 36~~35~~
City's Franchise Fee	Sheet No. 37~~36~~
School Tax	Sheet No. 38~~37~~

Continued on Sheet 5-5

Tariff R.S.-L.M.-T.O.D. Continued
(Residential Service Load Management Time of Day)

Delayed Payment Charge

Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. Residential customers are not subject to a delayed payment charge.

Separate Metering Provision

Customers who use electric thermal storage space heating and water heaters which consume energy only during off-peak hours specified by the Company, or other automatically controlled load management devices such as space and/or water heating equipment that use energy only during off-peak hours specified by the Company, shall have the option of having these approved load management devices separately metered. The service charge for the separate meter shall be $4.4530 per month.

Separate Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service. Existing customers may initially choose to take service under this tariff without satisfying any requirements to remain on their current tariff for at least 12 months.

The Company reserves the right to inspect at all reasonable times the energy storage and load management devices which qualify the residence for service and for conservation and load management credits under this tariff, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds, that in its sole judgment, the availability conditions of this tariff are being violated; it may discontinue billing the Customer under this tariff and commence billing under the appropriate Residential Service Tariff.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP1 or by special agreement with the Company.

Continued on Sheet 5-6

Tariff R.S.-T.O.D.
(Residential Service Time of Day)

Availability of Service
Available for residential electric service through a multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods to individual residential customers, including residential customers engaged principally in agricultural pursuits. Availability is limited to the first 1,000 customers applying for service under this tariff.

Rate *(Tariff Code 036)*

Service Charge	$~~23.00~~ 29.00	per month
Energy Charge		
All kWh used during on-peak billing period	~~17.335~~ 19.962¢	per kWh
All kWh used during off-peak billing period	9.317¢	per kWh

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 33~~32~~
Decommissioning Rider	Sheet No. 34~~33~~
Securitized Surcharge Rider	Sheet No. 35~~34~~
Federal Tax Cut Tariff	Sheet No. 36~~35~~
City's Franchise Fee	Sheet No. 37~~36~~
School Tax	Sheet No. 38~~37~~

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5~~2 4~~. Residential customers are not subject to a delayed payment charge.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

Continued on Sheet 5-7

Tariff R.S.-T.O.D.2
(Experimental Residential Service Time of Day 2)

Availability of Service

Available on a voluntary, experimental basis to individual residential customers for residential electric service through a multi-register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff.

Rate *(Tariff Code 027)*

Service Charge	$~~23.00~~ 29.00	per month
Energy Charge		
All kWh used during Summer on-peak billing period	~~18.291~~ 20.702¢	per kWh
All kWh used during Winter on-peak billing period	~~13.426~~ 17.881¢	per kWh
All kWh used during off-peak billing period	~~12.167~~ 12.980¢	per kWh

For the purpose of this tariff, the on-peak and off-peak billing periods shall be defined as follows:

Months Approximate Percent (%) of Annual Hours	**On-Peak** 16%	**Off-Peak** 84%
Winter Period: November 1 to March 31	7:00 AM to 11:00 AM 6:00 PM to 10:00 PM	11:00 AM to 6:00 PM 10:00 PM to 7:00 AM
Summer Period: May 15 to September 15	Noon to 6:00 PM	6:00 PM to Noon
All Other Calendar Periods	None	Midnight to Midnight

Note: All kWh consumed during Saturday and Sunday are billed at the off-peak level.

Minimum Charge

This tariff is subject to a minimum monthly charge equal to the Service Charge.

Continued on Sheet 5-8

Tariff R.S.-T.O.D.2 Continued
(Experimental Residential Service Time of Day 2)

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 3332
Decommissioning Rider	Sheet No. 3433
Securitized Surcharge Rider	Sheet No. 3534
Federal Tax Cut Tariff	Sheet No. 3635
City's Franchise Fee	Sheet No. 3736
School Tax	Sheet No. 3837

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. Residential customers are not subject to a delayed payment charge.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP-I or by special agreement with the Company.

Continued on Sheet 5-9

Tariff R.S.D.
(Residential Demand-Metered Electric Service)

Availability of Service
Available for residential electric service through one single-phase multiple-register demand meter. Availability is limited to the first 1,000 customers applying for service under this tariff.

Monthly Rate *(Tariff Code 018)*

Service Charge	$~~23.00~~ 26.00	per customer
Energy Charge		
All kWh used during on-peak billing period	~~9.861~~ 14.464¢	per kWh
All kWh used during off-peak billing period	9.317¢	per kWh
Demand Charge	$~~5.90~~8.01	for each kW of monthly billing demand

For the purpose of this tariff, the on-peak billing period is defined as follows:

Months of October – May:	7:00 AM to 11:00 AM for all weekdays
Months of June – September	4:00 PM to 9:00 PM for all weekdays

The off-peak billing period is defined as all weekday hours not defined above as on-peak and all hours of Saturday and Sunday

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 33~~32~~
Decommissioning Rider	Sheet No. 34~~33~~
Securitized Surcharge Rider	Sheet No. 35~~34~~
Federal Tax Cut Tariff	Sheet No. 36~~35~~
City's Franchise Fee	Sheet No. 37~~36~~
School Tax	Sheet No. 38~~37~~

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5~~2 4~~. Residential customers are not subject to a delayed payment charge.

Monthly Billing Demand
Customer's demand will be taken monthly to be the highest registration of a 60 minute integrating demand meter or indicator during the on- peak period.

Continued on Sheet 5-10

Tariff R.S.D.
(Residential Demand-Metered Electric Service)

Special Terms and Conditions

This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Tariff G.S.
(General Service)

Availability of Service
Available for general service customers. Customers may continue to qualify for service under this tariff until their average maximum demand exceeds 100 kW (excluding the demand served by the Load Management Time-of-Day provision).

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

Rate

Tariff Code	Service Voltage	Demand Charge ($/kW)	First 4,450 kWh (¢/kWh)	Over 4,450 kWh (¢/kWh)	Monthly Service Charge ($)
211, 212, 215, 216, 218	Secondary	13.24~~8.36~~	14.562~~13.060~~	11.853~~11.581~~	31.00~~28.00~~
217, 220	Primary	11.85~~7.56~~	12.887~~11.558~~	10.543~~10.301~~	140.00~~120.00~~
236	Subtransmission	9.07~~5.84~~	11.742~~10.531~~	9.618~~9.397~~	460.00

The Demand Charge shall apply to all monthly billing demand in excess of 10 kW.

Minimum Charge
This tariff is subject to a minimum charge equal to the sum of the service charge plus the demand charge multiplied by the monthly billing demand in excess of 10 kW.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 33~~32~~
Decommissioning Rider	Sheet No. 34~~33~~
Securitized Surcharge Rider	Sheet No. 35~~34~~
Federal Tax Cut Tariff	Sheet No. 36~~35~~
City's Franchise Fee	Sheet No. 37~~36~~
School Tax	Sheet No. 38~~37~~

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5~~2-4~~.

Metered Voltage
The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

Continued on Sheet 6-2

Tariff G.S. Continued
(General Service)

Metered Voltage Continued

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Monthly Billing Demand

Energy supplied hereunder will be delivered through not more than one single phase and/or polyphase meter. Customer's demand will be taken monthly to be the highest registration of a 15-minute integrating demand meter or indicator, or the highest registration of a thermal type demand meter. The monthly billing demand shall be the greater of: (1) Customer's metered kW demand, (2) 60% of the Customer's contract capacity in excess of 100 kW, or (3) 60% of the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 KW.

The Company reserves the right to install a demand meter on any customer receiving service under this tariff. A demand meter will be installed by the Company for customers with monthly kWh usage of 4,450 kWh or greater.

Recreational Lighting Service Provision

Available for service to customers with demands of 5 KW or greater and who own and maintain outdoor lighting facilities and associated equipment utilized at baseball diamonds, football stadiums, parks and other similar recreational areas. This service is available only during the hours between sunset and sunrise. Daytime use of energy under this rate is strictly forbidden except for the sole purpose of testing and maintaining the lighting system. All Terms and Conditions of Service applicable to Tariff G.S. customers will also apply to recreational lighting customers except for the Availability of Service.

Rate *(Tariff Code 214)*

Service Charge	$31.00~~28.00~~	per month
Energy Charge	15.950~~14.015~~¢	per kWh

Load Management Time of Day Provision

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements. This provision is also available for electric vehicle charging if separately metered.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

Rate *(Tariff Codes 223 and 225)*

Service Charge	$31.00~~28.00~~	per month
Energy Charge		
All kWh used during on-peak billing period	~~19.211~~ 22.953¢	per kWh
All kWh used during off-peak billing period	~~9.269~~ 9.493¢	per kWh

Continued on Sheet 6-3

Tariff G.S. Continued
(General Service)

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Optional Unmetered Service Provision
Available to customers who qualify for Tariff G.S., have a demand of less than 10 KW, and use the Company's service for commercial purposes consisting of small fixed electric loads such as traffic signals and signboards which can be served by a standard service drop from the Company's existing secondary distribution system. This service will be furnished at the option of the Company.

Each separate service delivery point shall be considered a contract location and shall be separately billed under the service contract. In the event one Customer has several accounts for like service, the Company may meter one account to determine the appropriate kilowatt-hour usage applicable for each of the accounts.

The Customer shall furnish switching equipment satisfactory to the Company. The Customer shall notify the Company in advance of every change in connected load, and the Company reserves the right to inspect the customer's equipment at any time to verify the actual load. In the event of the customer's failure to notify the Company of an increase in load, the Company reserves the right to refuse to serve the contract location thereafter under this provision, and shall be entitled to bill the customer retroactively on the basis of the increased load for the full period such load was connected or the earliest date allowed by Kentucky statute whichever is applicable.

Calculated energy use per month shall be equal to the contract capacity specified at the contract location times the number of days in the billing period times the specified hours of operation. Such calculated energy shall then be billed at the following rates:

Rate *(Tariff Codes 204 (Metered) and 213 (Unmetered))*

Customer Charge	$17.00~~15.00~~	per month
Energy Charge		
First 4,450 kWh per month	~~13.060~~ 14.562¢	per kWh
All Over 4,450 kWh per month	~~11.581~~ 11.853¢	per kWh

Term of Contract
Contracts under this tariff may be required of customers. Contracts under this tariff will be made for an initial period of not less than l (one) year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company will have the right to make contracts for periods of longer than 1 (one) year.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum demand in KW which the Company might be required to furnish, but no less than 10 KW. The Company shall not be obligated to supply demands in excess of that contracted for. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

Continued on Sheet 6-4

Tariff S.G.S.-T.O.D.
(Small General Service Time of Day Service)

Special Terms and Conditions Continued
This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point of both their power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP ~~I or II~~ or by special agreement with the Company.

Availability of Service
Available on a voluntary, basis for general service to customers being served at secondary distribution voltage with one single-phase, multi- register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff.

Customers not meeting the requirements for availability under this tariff will be permitted to continue service under this tariff only for continuous service at the premises occupied on or prior to June 30, 2015.

Rate *(Tariff Code 227)*

Service Charge	$31.00~~28.00~~	per month
Energy Charge		
All kWh used during Summer on-peak billing period	~~20.185~~ 23.244¢	per kWh
All kWh used during Winter on-peak billing period	~~14.461~~ 22.547¢	per kWh
All kWh used during off-peak billing period	~~13.034~~ 14.004¢	per kWh

For the purpose of this tariff, the on-peak and off-peak billing periods shall be defined as follows:

Months Approximate Percent (%) of Annual Hours	**On-Peak** 16%	**Off-Peak** 84%
Winter Period: November 1 to March 31	7:00 AM to 11:00 AM 6:00 PM to 10:00 PM	11:00 AM to 6:00 PM 10:00 PM to 7:00 AM
Summer Period: May 15 to September 15	Noon to 6:00 PM	6:00 PM to Noon
All Other Calendar Periods	None	Midnight to Midnight

Note: All kWh consumed during weekends are billed at the off-peak level.

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Continued on Sheet 6-5

Tariff S.G.S.-T.O.D. Continued
(Small General Service Time of Day)

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 3332
Decommissioning Rider	Sheet No. 3433
Securitized Surcharge Rider	Sheet No. 3534
Federal Tax Cut Tariff	Sheet No. 3635
City's Franchise Fee	Sheet No. 3736
School Tax	Sheet No. 3837

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-52 4.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP 1 or by special agreement with the Company.

Continued on Sheet 6-6

DATE OF ISSUE: August 29, 2025February 8, 2024
DATE EFFECTIVE: Services Rendered On And After March 1, 2026January 16, 2024
ISSUED BY: /s/ Tanner S. WolframBrian K. West
TITLE: Director, Regulatory ServicesVice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 2023-00159 Dated XXXX XX, XXXXJanuary 19, 2024

Tariff M.G.S.-T.O.D.
(Medium General Service Time of Day)

Availability of Service
Available for general service to customers with average maximum demands greater than 10 KW but not more than 100 KW being served by a multi- register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff.

Rate *(Tariff Code 229)*

Service Charge	$31.00~~28.00~~	per month
Energy Charge		
All kWh used during on-peak billing period	~~19.211~~ 22.953¢	per kWh
All kWh used during off-peak billing period	~~9.269~~ 9.493¢	per kWh

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 33~~32~~
Decommissioning Rider	Sheet No. 34~~33~~
Securitized Surcharge Rider	Sheet No. 35~~34~~
Federal Tax Cut Tariff	Sheet No. 36~~35~~
City's Franchise Fee	Sheet No. 37~~36~~
School Tax	Sheet No. 38~~37~~

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5~~2 4~~.

Continued on Sheet 6-7

Tariff M.G.S.-T.O.D. Continued
(Medium General Service Time of Day)

Metered Voltage

The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service. Existing customers may initially choose to take service under this tariff without satisfying any requirements to remain on their current tariff for at least 12 months.

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP~~1~~ or by special agreement with the Company.

Tariff L.G.S.
(Large General Service)

Availability of Service

Available for general service to customers with average maximum demands greater than 100 KW but not more than 1,000 KW (excluding the demand served by the Load Management Time-of-Day provision).

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

Rate

	Service Voltage			
	Secondary	**Primary**	**Subtransmission**	**Transmission**
Tariff Code	240, 242, 260	244, 246, 264	248, 268	250, 270
Service Charge per Month	$111.00~~97.00~~	$166.00~~145.00~~	$849.00~~750.00~~	$849.00~~750.00~~
Demand Charge per kW	$15.76~~13.84~~	$13.93~~12.23~~	$9.64~~8.46~~	$9.43~~8.28~~
Excess Reactive Charge per KVA	$3.46	$3.46	$3.46	$3.46
Energy Charge per kWh	~~8.966~~10.238¢	~~8.120~~9.339¢	~~6.292~~7.127¢	~~6.198~~7.008¢

Minimum Charge

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

Adjustment Clauses

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 33~~32~~
Decommissioning Rider	Sheet No. 34~~33~~
Securitized Surcharge Rider	Sheet No. 35~~34~~
Federal Tax Cut Tariff	Sheet No. 36~~35~~
City's Franchise Fee	Sheet No. 37~~36~~
School Tax	Sheet No. 38~~37~~

Delayed Payment Charge

Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5~~2-4~~.

Continued on Sheet 7-2

DATE OF ISSUE: ~~January 2, 2025~~August 29, 2025
DATE EFFECTIVE: Services Rendered On And After ~~December 31, 2024~~March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00008~~ Dated ~~December 13, 2024~~XXXX XX, XXXX

Tariff L.G.S. Continued
(Large General Service)

Metered Voltage
The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Monthly Billing Demand
Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

Determination of Excess Kilovolt-Ampere (KVA) Demand
The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

Load Management Time of Day Provision
Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements. This provision is also available for electric vehicle charging if separately metered.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

Rate *(Tariff Code 251)*

Service Charge	$111.00~~97.00~~	per month
Energy Charge		
All kWh used during on-peak billing period	~~16.700~~20.310¢	per kWh
All kWh used during off-peak billing period	~~9.407~~9.677¢	per kWh

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Continued on Sheet 7-3

Tariff L.G.S. Continued
(Large General Service)

Term of Contract

Contracts under this tariff will be made for customers requiring a average maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than l (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

Contract Capacity

The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

Continued on Sheet 7-4

Tariff L.G.S.-T.O.D.
(Large General Service Time of Day)

Availability of Service

Available for general service customers with average maximum demands of 100 KW or greater. Customers may continue to qualify for service under this tariff until their 12-month average demand exceeds 1,000 KW. Availability is limited to the first 500 customers applying for service under this tariff.

Rate

	Service Voltage			
	Secondary	**Primary**	**Subtransmission**	**Transmission**
Tariff Code	256	257	258	259
Service Charge per Month	$111.00~~97.00~~	$166.00~~145.00~~	$849.00~~750.00~~	$849.00~~750.00~~
Demand Charge per kW	$13.10~~9.33~~	$10.78~~7.91~~	$4.97~~4.39~~	$4.90~~4.32~~
Excess Reactive Charge per KVA	$3.46	$3.46	$3.46	$3.46
On-Peak Energy Charge per kWh	~~13.416~~14.753¢	~~12.820~~14.084¢	~~12.646~~13.880¢	~~12.499~~13.709¢
Off-Peak Energy Charge per kWh	~~6.906~~7.170¢	~~6.734~~6.958¢	~~6.684~~6.894¢	~~6.642~~6.840¢

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M., for all weekdays Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Minimum Charge

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

Adjustment Clauses

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 33~~32~~
Decommissioning Rider	Sheet No. 34~~33~~
Securitized Surcharge Rider	Sheet No. 35~~34~~
Federal Tax Cut Tariff	Sheet No. 36~~35~~
City's Franchise Fee	Sheet No. 37~~36~~
School Tax	Sheet No. 38~~37~~

Delayed Payment Charge

Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5~~2-4~~.

Continued on Sheet 7-5

DATE OF ISSUE: ~~January 2, 2025~~ August 29, 2025
DATE EFFECTIVE: Services Rendered On And After ~~December 31, 2024~~March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00008~~ Dated ~~December 13, 2024~~ XXXX XX, XXXX

Tariff L.G.S.-T.O.D. Continued
(Large General Service Time of Day)

Metered Voltage
The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Monthly Billing Demand
Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

Determination of Excess Kilovolt-Ampere (KVA) Demand
The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

Term of Contract
Contracts under this tariff will be made for customers requiring a average maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than l (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

Contract Capacity
The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

Continued on Sheet 7-6

Tariff L.G.S.-T.O.D. Continued
(Large General Service Time of Day)

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP ~~I or II~~ or by special agreement with the Company.

Tariff I.G.S.
(Industrial General Service)

Availability of Service

Available for commercial and industrial customers with contract demands of at least 1,000 KW. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet average maximum requirements.

Rate

	Service Voltage			
	Secondary	**Primary**	**Subtransmission**	**Transmission**
Tariff Code	356	358/370	359/371	360/372
Service Charge per Month	$276.00	$276.00	$794.00	$1,353.00
Demand Charge per kW				
Of monthly on-peak billing demand	$30.52~~26.99~~	$28.33~~24.94~~	$19.55~~17.36~~	$19.16~~17.00~~
Of monthly off-peak billing demand	$2.08~~1.84~~	$2.01~~1.78~~	$1.98~~1.75~~	$1.96~~1.73~~
Energy Charge per kWh	~~3.924~~4.537¢	~~3.775~~4.331¢	~~3.732~~4.269¢	~~3.695~~4.216¢
Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand……..				$0.69/KVAR

For the purpose of this tariff, the on-peak billing period is defined as 7:00 AM to 9:00 PM for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays and all hours of Saturday and Sunday.

Minimum Demand Charge

The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:

Secondary	**Primary**	**Subtransmission**	**Transmission**
$31.91 ~~25.68~~ / kW	$29.68 ~~23.68~~ / kW	$20.88 ~~16.12~~ / kW	$20.46 ~~15.77~~ / kW

The minimum billing demand shall be the greater of 60% of the contract capacity set forth on the contract for electric service or 60% of the highest billing demand, on-peak or off-peak, recorded during the previous eleven months.

Minimum Charge

This tariff is subject to a minimum charge equal to the Service Charge plus the Minimum Demand Charge.

Adjustment Clauses

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 33~~32~~
Decommissioning Rider	Sheet No. 34~~33~~
Securitized Surcharge Rider	Sheet No. 35~~34~~
Federal Tax Cut Tariff	Sheet No. 36~~35~~
City's Franchise Fee	Sheet No. 37~~36~~
School Tax	Sheet No. 38~~37~~

Continued on Sheet 8-2

DATE OF ISSUE: ~~January 2, 2025~~ August 29, 2025
DATE EFFECTIVE: Services Rendered On And After ~~December 31, 2024~~March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00008~~ Dated ~~December 13, 2024~~ XXXX XX, XXXX

Tariff I.G.S. Continued
(Industrial General Service)

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5~~2-4~~.

Metered Voltage
The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KVA values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Monthly Billing Demand
The monthly on-peak and off-peak billing demands in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered by a demand meter during the on-peak and off-peak billing periods, respectively.

The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVARs as registered during the month by a demand meter or indicator.

Term of Contract
Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

Contract Capacity
The Customer shall set forth the amount of capacity contracted for ("the contract capacity") in an amount equal to or greater than 1,000 KW in multiples of 100 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for resale service to mining and industrial Customers who furnish service to Customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point for both the power and camp requirements.

Continued on Sheet 8-3

Tariff I.G.S. Continued
(Industrial General Service)

Special Terms and Conditions Continued

This tariff is also available to Customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum amount of demand in KW which the Company might be required to furnish, but not less than 1,000 KW. The Company shall not be obligated to supply demands in excess of that contracted capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP-II or by special agreement with the Company.

Applicable on and after March 18, 2025, to existing commercial and industrial customers that add 150 MW or more of incremental load and new commercial and industrial customers that have at least 150 MW. The following terms and conditions apply:

Contracts will be made for an initial period of twenty (20) years and shall remain in effect thereafter unless cancelled or modified pursuant to the terms hereunder.

Either party shall give at least five years' written notice to the other of the intention to discontinue service under the terms of this Schedule. Such notice shall not reduce the twenty-year initial term. In the event of a permanent closure by the customer occurring after the first five (5) years of the initial contract term, the customer may exit the contract by providing a one-time payment equal to five (5) years of minimum billing under this Schedule.

The customer shall give at least five (5) years' written notice to the Company of the intention to reduce the contract capacity specified in the contract, but any contract capacity changes may be implemented with less than five (5) years notice with mutual agreement. Such notice shall not reduce the maximum contract capacity established during the term of the contract by more than 20%, except by mutual agreement. Such notice shall not be given and will not be accepted during the first five (5) years of the initial contract term.

In addition to the Monthly Billing Demand provisions, the customer's monthly billing demand shall in no event be less than 90% of the greater of (a) the customer's on-peak contract capacity or b) the customer's highest previously established monthly billing demand during the past 11 months or (c) the customer's maximum demand created during the billing month.

The customer shall provide collateral in a form acceptable to the Company based upon the creditworthiness of the customer. The amount of collateral provided shall be equal to 24 times the customer's previous maximum monthly non-fuel bill. During the first year of the contract, the maximum expected bill for the year shall be used. The amount of collateral to be provided will be recomputed annually, and updated if the recomputed value is 10% greater than the current amount held.

Tariff M.W.
(Municipal Waterworks)

Availability of Service
Available only to incorporated cities and towns and authorized water districts and to utility companies operating under the jurisdiction of Public Service Commission of Kentucky for the supply of electric energy to waterworks systems and sewage disposal systems served under this tariff on September 1, 1982, and only for continuous service at the premises occupied by the Customer on this date. If service hereunder is discontinued, it shall not again be available.

Customer shall contract with the Company for a reservation in capacity in kilovolt-amperes sufficient to meet with the maximum load, which the Company may be required to furnish.

Rate *(Tariff Code 540)*

Service Charge	$28.00 ~~25.00~~	per month
Energy Charge All kWh used per month	~~11.841~~ 13.979¢	per kWh

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the sum of the service charge plus $10.229.55 per KVA as determined from customer's total connected load.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 3332
Decommissioning Rider	Sheet No. 3433
Securitized Surcharge Rider	Sheet No. 3534
Federal Tax Cut Tariff	Sheet No. 3635
City's Franchise Fee	Sheet No. 3736
School Tax	Sheet No. 3837

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-52 ~~4~~.

Term of Contract
Contracts under this tariff will be made for not less than (1) one year with self-renewal provisions for successive periods of (1) one year each until either party shall give at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period. The Company will have the right to require contracts for periods of longer than (1) one year.

Continued on Sheet 9-2

DATE OF ISSUE: August 29, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated XXXX XX, XXXX

Tariff M.W. Continued
(Municipal Waterworks)

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is not available to customers having other sources of energy supply.

Tariff O.L.
(Outdoor Lighting)

Availability of Service

Available for outdoor lighting to individual customers in locations where municipal street lighting is not applicable provided the lighting location designated by the Customer is reasonably accessible to the Company's service vehicles without causing damage to the Customer's or other's property. New installations of High Pressure Sodium, Mercury Vapor and Metal Halide lamps shall cease on January 14, 2021.

Base Fuel Rate

Customers receiving service under this tariff will receive bills calculated using per lamp and base fuel charge. The base fuel charge will be calculated each month as shown below by multiplying the approved base fuel amount set forth in the Company's Fuel Adjustment Clause tariff by the relevant monthly kWh value set forth in the monthly kWh table included below in the Adjustment Clauses section of this tariff.

Rate

A. Overhead Lighting Service

	Tariff Code	Watts	Rate	
High Pressure Sodium	094	100 (9,500 Lumens)	$11.84~~10.25~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	113	150 (16,000 Lumens)	$13.50~~11.69~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	097	200 (22,000 Lumens)	$16.36~~14.17~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	103	250 (28,000 Lumens)	$23.32~~20.19~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	098	400 (50,000 Lumens)	$25.84~~22.38~~	per lamp + 0.03380 x kWh in Sheet No. 10-4

	Tariff Code	Watts	Rate	
Mercury Vapor	093	175 (7,000 Lumens)	$15.09~~13.07~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	095	400 (20,000 Lumens)	$25.97~~22.49~~	per lamp + 0.03380 x kWh in Sheet No. 10-4

	Tariff Code	Lumens	Rate	
LED	150	6,000-10,000	$8.65~~7.49~~	per lamp + 0.03380 x kWh in Sheet No. 10-4

Company will provide lamp, photo-electric relay control equipment, luminaries and upsweep arm not over six feet in length, and will mount same on an existing pole carrying secondary circuits.

B. Post-Top Lighting Service

	Tariff Code	Watts	Rate	
High Pressure Sodium	111	100 (9,500 Lumens)	$21.46~~18.58~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	122	150 (16,000 Lumens)	$33.75~~29.23~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	120	250 (19,000 Lumens)	$39.29~~34.02~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	126	400 (40,000 Lumens)	$51.57~~44.66~~	per lamp + 0.03380 x kWh in Sheet No. 10-4

	Tariff Code	Watts	Rate	
Mercury Vapor	099	175 (7,000 Lumens)	$17.31~~14.99~~	per lamp + 0.03380 x kWh in Sheet No. 10-4

Continued on Sheet 10-2

DATE OF ISSUE: ~~January 2, 2025~~August 29, 2025
DATE EFFECTIVE: Services Rendered On And After ~~December 31, 2024~~March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00008~~ Dated ~~December 13, 2024~~XXXX XX, XXXX

Tariff O.L. Continued
(Outdoor Lighting)

Post-Top Lighting Service Continued

	Tariff Code	Lumens	Rate	
LED	160	6,000-10,000	$24.90~~21.56~~	per lamp + 0.03380 x kWh in Sheet No. 10-4

Company will provide lamp photo-electric relay control equipment, luminaries, post, and installation including underground wiring for a distance of thirty feet from the Company's existing secondary circuits. Incremental costs of installation beyond thirty feet shall be the responsibility of the customer.

C. Flood Lighting Service

	Tariff Code	Watts	Rate	
High Pressure Sodium	107	200 (22,000 Lumens)	$18.79~~16.27~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	109	400 (50,000 Lumens)	$27.44~~23.76~~	per lamp + 0.03380 x kWh in Sheet No. 10-4

	Tariff Code	Watts	Rate	
Metal Halide	110	250 (20,500 Lumens)	$22.80~~19.74~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	116	400 (36,000 Lumens)	$28.72~~24.87~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	131	1,000 (110,000 Lumens)	$52.28~~45.27~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	130	250 Mongoose (20,500 Lumens)	$29.74~~25.75~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	136	400 Mongoose (36,000 Lumens)	$36.30~~31.43~~	per lamp + 0.03380 x kWh in Sheet No. 10-4

	Tariff Code	Lumens	Rate	
LED	165	17,500-22,500	$32.33~~28.00~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	166	42,500-47,500	$39.73~~34.40~~	per lamp + 0.03380 x kWh in Sheet No. 10-4

Company will provide lamp, photoelectric relay control equipment, luminaries, mounting bracket, and mount same on an existing pole carrying secondary circuits.

D. LED Lamp Conversion Charge
Existing outdoor lighting customers that wish to convert from non-LED lamps to new LED fixtures shall pay a monthly charge of $3.33 per lamp replaced, per month for 84 months.

All lumen figures are based upon manufacturer estimates and may vary.

When new or additional facilities, other than those specified in Paragraphs A, B, and C, are to be installed by the Company, the customer in addition to the monthly charges, shall pay in advance the installation cost (labor and material) of such additional facilities extending from the nearest or most suitable pole of the Company to the point designated by the customer for the installation of said lamp, except that customer may, for the following facilities only, elect, in lieu of such payment of the installation cost to pay:

Continued on Sheet 10-3

Tariff O.L. Continued
(Outdoor Lighting)

Post-Top Lighting Service Continued

Wood Pole	$4.70~~4.08~~	per month
Overhead wire span not over 150 feet	$2.25~~2.26~~	per month
Underground wire lateral not over 50 feet	$7.65~~7.66~~	per month

(Price includes pole riser and connections)

E. Flexible Lighting Option *(Tariff Code 175 for Unmetered and Tariff Code 201 for Metered)*
Applicable for the installation of any outdoor area lighting system (System) on a private or public property and owned by the Company. The customer must be adjacent to an electric power line of the Company that is adequate for supplying the necessary electric service. Service for the System under this tariff shall require a contract addendum agreed to and signed by the customer. The System shall comply with the Company's terms and conditions unless otherwise noted in this section. Included in the contract addendum shall be the installed capital cost of the System and the monthly amount of kWh the System will use if it is not metered. The Company reserves the right to refuse service under this provision based on customer's creditworthiness.

Rate
Customers shall pay the monthly lamp charge for the System, a monthly maintenance charge, a non-fuel energy charge, a base fuel charge, and all applicable adjustment clauses.

Monthly Lamp Charge* = IC x MLFCR

Where:
IC = Installed Cost of System
MLFCR = Monthly Levelized Fixed Cost Rate of ~~1.42~~1.48% which is inclusive of return, depreciation, income taxes, property taxes and A&G expense components

Monthly maintenance charge is $2.53~~0.80~~ per lamp per month
Monthly non-fuel charge is 0.08523~~.08561~~ $/kWh
Base fuel charge is 0.03380 $/kWh

Customers selecting this flexible lighting option to replace existing lamps shall also be subject to the LED Lamp Conversion Charge.

*Customers may pay a portion of the installed cost upfront to reduce the monthly lamp charge component of the rate.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 33~~32~~
Decommissioning Rider	Sheet No. 34~~33~~
Securitized Surcharge Rider	Sheet No. 35~~34~~
Federal Tax Cut Tariff	Sheet No. 36~~35~~
City's Franchise Fee	Sheet No. 37~~36~~
School Tax	Sheet No. 38~~37~~

Continued on Sheet 10-4

DATE OF ISSUE: ~~January 2, 2025~~August 29, 2025
DATE EFFECTIVE: Services Rendered On And After ~~December 31, 2024~~March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00008~~ Dated ~~December 13, 2024~~XXXX XX, XXXX

Tariff O.L. Continued
(Outdoor Lighting)

For adjustments calculated on a per kWh basis the following kWh values will be used in the calculation:

	Metal Halide			Mercury Vapor		High Pressure Sodium				
	250 Watts	400 Watts	1,000 Watts	175 Watts	400 Watts	100 Watts	150 Watts	200 Watts	250 Watts	400 Watts
Jan	127	199	477	91	199	51	74	106	130	210
Feb	106	167	400	76	167	43	62	89	109	176
Mar	106	167	400	76	167	43	62	89	109	176
Apr	90	142	340	65	142	36	53	76	93	150
May	81	127	304	58	127	32	47	68	83	134
Jun	72	114	272	52	114	29	42	61	74	120
Jul	77	121	291	55	121	31	45	65	79	128
Aug	88	138	331	63	138	35	51	74	90	146
Sep	96	152	363	69	152	39	57	81	99	160
Oct	113	178	427	81	178	45	66	95	116	188
Nov	119	188	449	86	188	48	70	100	122	198
Dec	129	203	486	92	203	52	75	108	132	214
Total	1,204	1,896	4,540	864	1,896	484	704	1,012	1,236	2,000

	Light Emitting Diode (LED)			
	150 Tariff Code 6,000-10,000 Lumens	160 Tariff Code 6,000-10,000 Lumens	165 Tariff Code 17,500-22,500 Lumens	166 Tariff Code 42,500-47,500 Lumens
Jan	28	33	75	154
Feb	24	28	63	129
Mar	24	28	63	129
Apr	20	24	53	109
May	18	21	48	96
Jun	16	19	43	87
Jul	17	20	46	93
Aug	19	23	52	105
Sep	22	26	58	118
Oct	25	30	67	136
Nov	27	32	71	145
Dec	29	33	77	156
Total	269	317	716	1,457

Continued on Sheet 10-5

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
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TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Tariff O.L. Continued
(Outdoor Lighting)

Delayed Payment Charge
Residential customers are not subject to a delayed payment charge. Other delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-52-4.

Hours of Lighting
All lamps shall burn from one-half hour after sunset until one-half hour before sunrise every night and all night, burning approximately 4,000 hours per annum.

Ownership of Facilities
All facilities necessary for service including fixtures, controls, poles, transformers, secondaries, lamps and other appurtenances shall be owned and maintained by the Company. All service and necessary maintenance will be performed only during the regular scheduled working hours of the Company.

The Company shall be allowed 3 working days after notification by the customer to replace all burned-out lamps.

Term of Initial Service
Term of initial service shall be required for a period of one year. If early termination is requested or service is terminated during the initial 12 month period, the customer will be billed for the remainder of the 12 month period on the final bill.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

The Company shall have the option of rendering monthly or bimonthly bills.

Customer's account balance must be current prior to installation of new or additional lights.

Tariff S.L.
(Street Lighting)

Availability of Service
Available for lighting service for all the lighting of public streets, public highways and other public outdoor areas in municipalities, counties, and other governmental subdivisions where such service can be supplied from the existing general distribution systems provided the lighting location designated by the Customer is reasonably accessible to the Company's service vehicles without causing damage to the Customer's or other's property. New installations of High Pressure Sodium lamps shall cease on January 14, 2021.

Base Fuel Rate
Customers receiving service under this tariff will receive bills calculated using per lamp and base fuel charge. The base fuel charge will be calculated each month as shown below by multiplying the approved base fuel amount set forth in the Company's Fuel Adjustment Clause tariff by the relevant monthly kWh value set forth in the monthly kWh table included below in the Adjustment Clauses section of this tariff.

Rate *(Tariff Code 528)*
A. Overhead Service on Existing Distribution Poles

	Watts	Rate	
High Pressure Sodium	100 (9,500 Lumens)	$10.02~~8.64~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	150 (16,000 Lumens)	$11.00~~9.49~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	200 (22,000 Lumens)	$13.03~~11.24~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	400 (50,000 Lumens)	$17.11~~14.76~~	per lamp + 0.03380 x kWh in Sheet No. 11-3

	Lumens	Rate	
LED	8,000-11,000	$11.47~~9.89~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	10,000-14,000	$14.72~~12.70~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	24,000-30,000	$17.55~~15.14~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 6,000-10,000	$11.91~~10.27~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 8,000-12,000	$26.41~~22.78~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Flood 17,500-22,500	$19.33~~16.67~~	per lamp + 0.03380 x kWh in Sheet No. 11-3

B. Service on New Wood Distribution Poles

	Watts	Rate	
High Pressure Sodium	100 (9,500 Lumens)	$15.66~~13.51~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	150 (16,000 Lumens)	$16.78~~14.47~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	200 (22,000 Lumens)	$18.82~~16.23~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	400 (50,000 Lumens)	$24.15~~20.83~~	per lamp + 0.03380 x kWh in Sheet No. 11-3

	Lumens	Rate	
LED	8,000-11,000	$18.90~~16.30~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	10,000-14,000	$22.17~~19.12~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	24,000-30,000	$25.01~~21.57~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 6,000-10,000	$19.34~~16.68~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 8,000-12,000	$33.85~~29.20~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Flood 17,500-22,500	$26.78~~23.10~~	per lamp + 0.03380 x kWh in Sheet No. 11-3

Continued on Sheet 11-2

DATE OF ISSUE: ~~January 2, 2025~~August 29, 2025
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By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00008~~ Dated ~~December 13, 2024~~XXXX XX, XXXX

Tariff S.L. Continued
(Street Lighting)

C. Service on New Metal or Concrete Poles*

	Watts	Rate	
High Pressure Sodium	100 (9,500 Lumens)	$32.63~~28.15~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	150 (16,000 Lumens)	$33.82~~29.17~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	200 (22,000 Lumens)	$35.86~~30.93~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	400 (50,000 Lumens)	$39.94~~34.45~~	per lamp + 0.03380 x kWh in Sheet No. 11-3

	Lumens	Rate	
LED	8,000-11,000	$33.03~~28.49~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	10,000-14,000	$35.24~~30.40~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	24,000-30,000	$36.98~~31.90~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 6,000-10,000	$34.01~~29.34~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 8,000-12,000	$48.34~~41.70~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Flood 17,500-22,500	$38.71~~33.39~~	per lamp + 0.03380 x kWh in Sheet No. 11-3

* Effective June 29, 2010 and thereafter these lamps are not available for new installations

D. LED Lamp Conversion Charge

Existing street lighting customers that wish to convert from non-LED lamps to a new LED fixture shall pay a monthly charge of $2.18 per lamp replaced, per month for 84 months.

All lumen figures are based upon manufacturer estimates and may vary.

E. Flexible Lighting Option *(Tariff Code 525 for Unmetered and Tariff Code 526 for Metered)*

Applicable for the installation of any street lighting system (System) on a private or public property and owned by the Company. The customer must be adjacent to an electric power line of the Company that is adequate for supplying the necessary electric service. Service for the System under this tariff shall require a contract addendum agreed to and signed by the customer. The System shall comply with the Company's terms and conditions unless otherwise noted in this section. Included in the contract addendum shall be the installed capital cost of the System and the monthly amount of kWh the System will use unless the system is separately metered. The Company reserves the right to refuse service under this provision based on customer's credit worthiness.

Rate

Customers shall pay the monthly lamp charge for the System, a monthly maintenance charge, a non-fuel energy charge, a base fuel charge, and all applicable adjustment clauses.

Monthly Lamp Charge* = IC x MLFCR

Where:
IC = Installed Cost of System
MLFCR = Monthly Levelized Fixed Cost Rate of 1.09~~1.04~~% which is inclusive of return, depreciation, income taxes, property taxes and A&G expense components

Continued on Sheet 11-3

Tariff S.L. Continued
(Street Lighting)

Monthly maintenance charge is $2.502.52 per lamp per month
Monthly non-fuel charge is 0.06102.05192 $/kWh
Base fuel charge is 0.03380 $/kWh

Customers selecting this flexible lighting option to replace existing lamps shall also be subject to the LED Lamp Conversion Charge.

*Customers may pay a portion of the installed cost upfront to reduce the monthly lamp charge component of the rate.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 3332
Decommissioning Rider	Sheet No. 3433
Securitized Surcharge Rider	Sheet No. 3534
Federal Tax Cut Tariff	Sheet No. 3635
City's Franchise Fee	Sheet No. 3736
School Tax	Sheet No. 3837

For adjustments calculated on a per kWh basis the following kWh values will be used in the calculation:

	High Pressure Sodium				Light Emitting Diode (LED)					
	100 Watts	150 Watts	200 Watts	400 Watts	8,000-11,000 Lumens	10,000-14,000 Lumens	24,000-30,000 Lumens	Post Top 6,000-10,000 Lumens	Post Top 8,000-12,000 Lumens	Flood 17,500-22,500 Lumens
Jan	51	74	106	210	35	49	98	33	48	75
Feb	43	62	89	176	30	40	83	28	41	63
Mar	43	62	89	176	30	40	83	28	41	63
Apr	36	53	76	150	25	34	70	24	34	53
May	32	47	68	134	22	30	62	21	31	48
Jun	29	42	61	120	20	27	56	19	27	43
Jul	31	45	65	128	21	29	60	20	29	46
Aug	35	51	74	146	23	33	68	23	32	52
Sep	39	57	81	160	27	37	75	26	37	58
Oct	45	66	95	188	31	43	87	30	43	67
Nov	48	70	100	198	33	46	93	32	45	71
Dec	52	75	108	214	36	50	100	33	50	77
Total	484	704	1,012	2,000	333	458	935	317	458	716

Continued on Sheet 11-4

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TITLE: Director, Regulatory ServicesVice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 2023-00159 Dated XXXX XX, XXXXJanuary 19, 2024

Tariff S.L. Continued
(Street Lighting)

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-52 4.

Special Facilities
When a customer requests street lighting service which requires special poles or fixtures, underground street lighting, or a line extension of more than one span of approximately 150 feet, the customer will be required to pay, in advance, an aid-to-construction in the amount of the installed cost of such special facilities.

Hours of Lighting
All lamps shall burn from one-half hour after sunset until one-half hour before sunrise every night and all night, burning approximately 4,000 hours per annum.

Term of Contract
Contracts under this tariff will ordinarily be made for an initial term of one year with self-renewal provisions for successive periods of one year each until either party shall give at least 60 days' notice to the other of the intention to discontinue at the end of the initial term or any yearly period. The Company may have the right to require contracts for periods of longer than one year if new or additional facilities are required.

Special Terms and Conditions
A customer's account balances must be current prior to installation of new or additional lights.

Tariff P.A.
(Pole Attachments)

1. Availability of Service

Available to broadband internet providers, cable television system operators, governmental units and telecommunications carriers that provide service within the operating area of Kentucky Power Company (Company). This Tariff is not available to: (1) the Attachments of utilities, including local exchange carriers (LECs), that have joint use agreements with Company; or (2) macro cell facilities. Nothing in this Tariff expands the right to attach to Company's facilities beyond the rights otherwise conveyed by law.

2. Definitions

Unless stated otherwise, the terms used in this Tariff shall have the same meaning as the terms expressly defined in Section 1 of 807 KAR 5:015.

"Approved Contractor" means a contractor approved by Company for a particular purpose.

"Attachment" means a Wireline Facility or Wireless Facility and all associated equipment, including without limitation, any overlashed cable or fiber, guying, small splice panels and vertical overhead to underground risers but shall not include power supplies, equipment cabinets, meter bases or other equipment that impedes accessibility or otherwise conflicts with Company's standards. For billing purposes, the term "Attachment" also includes: (1) a Service Drop affixed to a pole that is located more than one (1) vertical foot away from the point at which the messenger strand is attached to the pole; and (2) a Service Drop located on a dedicated service, drop or lift pole.

"Communications Space" means the area on a pole below the Communications Worker Safety Zone and above the point on the pole necessary to meet NESC clearance, department of transportation or other governmental requirements, and Company's construction standards.

"Facility" means any Company Distribution Pole, right-of-way, conduit or duct normally used by Company to support or protect its electric conductors. The term "Facility" does not include any Transmission Pole.

"Distribution Pole" means a utility pole supporting electric supply facilities, all of which operate at less than 69kV, but does not include a pole used primarily to support outdoor lighting.

"NESC" means the National Electrical Safety Code.

"Larger Order" means an application, or multiple applications submitted within thirty (30) days of one another, seeking to make Attachments to more than three hundred (300) poles except that for the period during which 807 KAR 5:015E is in effect, such term shall mean an application or applications submitted within thirty (30) days of one another seeking to make Attachments to more than 500 poles.

"Operator" means a broadband internet provider, cable television system operator, governmental unit or telecommunications carrier.

"Overlashing" means the practice whereby an entity, whether Operator or a third party, physically connects or attaches, through lashing or otherwise, new fiber optic or coaxial cable, or any other type of cable, to an existing Wireline Attachment on a Distribution Pole.

"Service Drop" means a Wireline Facility, attached to a pole with a J-hook or other similar hardware, that connects the trunk line to an end user's premises, and extends directly from the trunk line to a drop/lift pole or into an end user's premises.

Continued on Sheet 12-2

Tariff P.A. Continued
(Pole Attachments)

"Transmission Pole" means any utility pole or tower supporting electric supply facilities designed to operate at 69kV or greater.

"Wireline Facility" means fiber optic or coaxial cable, or any other type of cable, as well as any messenger wire or support strand.

"Wireless Facility" means, without limitation, antennas, risers, transmitters, receivers, and all other associated equipment used in connection with Operator's provision of wireless communications services and the transmission and reception of radiofrequency signals, but shall not include power supplies, equipment cabinets, meter bases, and other equipment that impedes accessibility or that conflicts with Company's standards. The term "Wireless Facility" does not include any strand-mounted antennas or macro cell facilities.

3. Rate

Charge for Wireline Facility on a two-user pole	$10.82	per attachment per year
Charge for Wireline Facility on a three-user pole	$6.71	per attachment per year

The above rate was calculated in accordance with the following formula:

Weighted Average Bare Pole Cost	x	Usage Factor	x	Carrying Charge	=	Rate Per Pole

A two-user pole is a pole being used, by actual occupation or reservation, by the Operator and the Company. A three-user pole is a pole being used by actual occupation or reservation, by the Operator, the Company, and a third party.

Charge for Attachments within ducts or conduits	$2.70	per linear foot per year
Charge for attachment of Wireless Facility to top of Distribution Pole	$150	per attachment per year
Charge for attachment of Wireless Facility within Communications Space of Distribution Pole	$75	per attachment per year

The above rates are subject to revision from time to time as approved by the Commission.

4. Company Facilities Subject to Attachment

Pursuant to 807 KAR 5:015 and the terms and conditions of this Tariff, Attachments to Company Facilities that do not interfere with Company's electric service requirements shall be permitted. Company may deny access to any Company Facility on a non-discriminatory basis where there is insufficient capacity or for reasons of safety, reliability, and generally applicable engineering purposes.

All Company Facilities covered by this Tariff remain the property of Company regardless of any payment by Operator toward their cost. No use, however extended, of Company Facilities or payment of any fee or charge required hereunder shall create or vest in Operator any claim or right, possession, title, interest or ownership in such Facilities. Nothing in this Tariff shall be construed to obligate Company to construct, reconstruct, retain, extend, repair, place, replace or maintain any Facility which, in Company's sole discretion, is not needed for Company's own purposes. Company and its successors and assigns shall have the right to operate, relocate and maintain Company Facilities in such a manner as will best enable Company, in its sole discretion, to fulfill its service requirements.

Continued on Sheet 12-3

Tariff P.A. Continued
(Pole Attachments)

5. Company's Pole Attachment Policy Handbook; Website

Operator is expected to follow the processes and guidelines set forth in Company's Pole Attachment Policy handbook, as well as any amendments thereto, but only to the extent that such processes and guidelines do not conflict with 807 KAR 5:015 (and 807 KAR 5:015E during the period such emergency regulation is effective) or this Tariff.

~~**Company's Pole Attachment Policy Handbook; Website Continued**~~

The Pole Attachment Policy handbook can be found at https://www.kentuckypower.com/business/b2b/pole-attachment. This website, which is maintained by Company, also includes: (a) the identity and contact information for contractors approved by Company to conduct surveys and self-help above the communications space; (b) Company's construction standards applicable to Attachments; (c) contact information for Company personnel responsible for invoicing, payment, make-ready work, and escalation of disputes; and (d) other relevant information.

Company reserves the right to update or revise the information posted on the above-referenced website from time to time. Attachment Customer shall ensure that it is utilizing up-to-date information before taking any action upon such information.

6. Applications

When Operator proposes to furnish service within Company's operating area and desires to make Attachments to Company Facilities, Operator shall make written application to install such Attachments, in the format required by Company, that specifies the location of each Facility in question, the character of its proposed Attachments, and any other information necessary to calculate the transverse and vertical load placed upon the pole as a result of the proposed Attachment and any other attachments or equipment attached to the Facility. If Operator's application qualifies as a Larger Order, Operator shall provide Company at least ninety (90) days' advance written notice before submission to Company. Company will notify Operator, within the time required by law, if the application is incomplete. If the application is incomplete, Operator shall provide the additional information required by Company prior to Company's review of the application on its merits.

If Operator is only seeking to make Wireline Attachments to Distribution Poles, Company shall complete a make-ready survey within the time required by law of receipt of a complete application. Company may, in its sole discretion, require prepayment for a make-ready survey. The current per pole estimate for a make-ready survey is $275. If the actual cost of performing the make-ready survey exceeds the amount of Operator's prepayment, then Operator shall reimburse Company for any difference upon receipt of an invoice for such amount. If the actual cost of performing the make-ready survey is less than the amount of Operator's prepayment, then Company shall issue Operator a refund for the difference. Company shall use commercially reasonable efforts to provide at least five (5) days advance notice of a field inspection to Operator and any other affected third party.

Within the time required by law after receipt of a complete application, Company shall notify Operator whether and to what extent any special conditions will be required to permit the use by Operator of each such pole. Within fourteen (14) days of providing such notice, Company shall provide Operator with a statement of the costs for any necessary Company make-ready work, including the cost of rearranging Company's electric supply facilities or pole changeouts. Operator shall indicate its approval of the make-ready cost statement by submitting payment to Company within fourteen (14) days of receipt of the make-ready cost statement. If payment is not received by Company within fourteen (14) days, then Company's make-ready cost statement shall be deemed withdrawn. Within seven (7) days of receipt of Operator's payment, Company shall notify, in a manner consistent with applicable law, all third parties whose attachments might be affected by the make-ready, and thereafter provide Operator with the contact information for, and copies of the notices sent to, such third parties. Thereafter, Operator shall be responsible for coordinating the rearrangement or transfer of any third-party attachment and shall pay the costs related thereto.

Continued on Sheet 12-4

Tariff P.A. Continued
(Pole Attachments)

Operator shall reimburse Company for any expenses incurred in reviewing Operator's written applications for attachment. Operator shall have a non-exclusive right to use such Facilities of Company as may be used or reserved for use by Operator and any other Facilities of Company when brought hereunder in accordance with the procedure hereinafter provided. Company shall have the right to grant to others, by contract or otherwise, rights or privileges to use any Facilities of Company and Company shall have the right to continue and extend any such rights or privileges heretofore granted.

7. Standards for Installation

All Attachments and associated equipment of Operator shall be installed in a manner satisfactory to Company and so as not to interfere with the present or any future use which Company may desire to make of the Facilities covered by this Tariff. All such Attachments and equipment shall be installed and at all times maintained by Operator so as to comply with the standards set forth in Company's Pole Attachment Policy handbook, the NESC and any other applicable regulations or codes promulgated by state, local or other governmental authority having jurisdiction thereover. In the event of a conflict, the more stringent standard shall apply. Operator shall take necessary precautions by the installation of protective equipment or other means, to protect all persons and property of all kinds against injury or damage occurring by reason of Operator's attachments.

Operator shall complete the installation of its Attachments within thirty (30) days of Company's approval of the application for such Attachments, or if make-ready is required to accommodate the Attachments, the completion date of such make-ready. Operator shall, within seven (7) days after completing the installation of its Attachments, provide Company with written notice of such completion (except that such notice may be provided within fifteen (15) days after completing the installation of Attachments during the period 807 KAR 5:015E is effective), and Company shall have the right to perform a post-inspection on such Attachments, at Operator's sole expense, within ninety (90) days of receipt of Operator's notice of completion. If Company's inspection reveals that Operator's installation resulted in any property damage or code violations, Company may either: (1) complete any necessary remedial work and bill Operator for the costs related to fixing the damage or correcting the code violations; or (2) require Operator to fix the damage or code violations at its own expense within fourteen (14) days' notice from Company.

8. Tagging Requirement

Operator shall identify each of its Attachments with a tag, approved in advance by Company, that includes Operator's name, 24-hour contact telephone number, and such other information as Company may require. Operator shall tag an Attachment at the time of construction. Any untagged Attachment existing as of the effective date of this Tariff shall be tagged by Operator by no later than June 30, 2025.

9. Overlashing

Operator shall provide Company with at least thirty (30) days' advance written notice before Overlashing, or allowing a third party to overlash, Operator's existing Wireline Facilities. Operator is responsible for all Overlashing performed on its Wireline Facilities, including any Overlashing by a third party, and shall ensure that all Overlashing complies with Company's standards, the applicable provisions of the NESC, and any other applicable law or code. If Overlashing of Operator's Wireline Facilities results in any damage to the pole, Company equipment or existing Attachments, or if any Overlashing causes a safety or engineering standard violation, Operator shall be responsible, at its expense, for any necessary repairs or corrections.

Continued on Sheet 12-5

Tariff P.A. Continued
(Pole Attachments)

Overlashing Continued

Operator shall notify Company within fifteen (15) days of completion of an overlash on a particular pole. Within ninety (90) days of receiving such notice, Company will perform an inspection at Operator's expense to determine whether the overlash caused any damage to Company property or resulted in any code violations. Company shall notify Operator of any damage to Company property or code violations within fourteen (14) days after completion of the inspection. At Company's discretion, Company may either: (1) complete any necessary remedial work and bill Operator for the costs related to fixing the damage or correcting the code violations; or (2) require Operator to fix the damage or code violations at its own expense within fourteen (14) days' notice from Company.

10. Pole Installation or Replacement; Rearrangements; Guying

In any case Operator proposes to install Attachments on a pole to be erected by Company in a new location, and such pole must, in Company's judgment, be taller and/or stronger than would be necessary to accommodate the facilities of Company and of other persons who have previously indicated that they desire to make attachments on such pole or with whom Company has an agreement providing for joint or shared ownership of poles, the cost of such extra height and/or strength shall be paid to Company by Operator. Such cost shall be the difference between the cost in place of the new pole and the current cost in place of a pole considered by Company to be adequate for the facilities of Company and the attachments of such other persons.

Where in Company's judgment a new pole must be erected to replace an existing pole solely to adequately provide for Operator's proposed Attachments, Operator agrees to pay Company for the entire cost of the new pole necessary to accommodate the existing facilities on the pole and Operator's proposed Attachments, plus the cost of removal of the in-place pole, minus the salvage value, if any, of the removed pole. Operator shall also pay to Company and to any other owner of existing attachments on the pole the cost of transferring each of their respective facilities or attachments to the newly-installed pole.

If Operator's desired Attachments can be accommodated on existing poles of Company by rearranging facilities of Company thereon or of any other person, or if because of Operator's proposed Attachments it is necessary for Company to rearrange its facilities on any pole not owned by it, then in any such case, Operator shall reimburse Company and any such other person for the respective expense incurred in making such rearrangement.

If because of the requirements of its business, Company intends to replace an existing pole on which Operator has any Attachment, or Company intends to change the arrangements of its facilities on any such pole in such manner as to necessitate a rearrangement of Operator's Attachment, or if as a result of any inspection of Operator's Attachments Company determines that any such Attachments are not in accordance with Company's standards, applicable codes or the provisions of this Tariff or are otherwise hazards Company shall give Operator not less than sixty (60) days' notice of such proposed replacement or change, or any such violation or hazard; provided, however, that the sixty (60) day notice requirement shall not apply to: (1) make-ready notices pursuant to Section 4 of 807 KAR 5:015 or 807 KAR 5:015E (during the period such emergency regulation is effective); (2) routine maintenance by Company; or (3) a replacement or change made by Company in response to an emergency. In such event, Operator shall at its expense relocate, rearrange or modify its Attachments at the time specified by Company. If Operator fails to do so, or if any such emergency makes notice impractical, Company shall perform such relocation or rearrangement and Operator shall reimburse Company for the reasonable cost thereof.

Any additional guying or anchors required by reason of the Attachments of Operator shall be provided at the expense of Operator and shall meet the requirements of all applicable codes or regulations and Company's generally applicable guying standards.

Continued on Sheet 12-6

Tariff P.A. Continued
(Pole Attachments)

11. Self-Help Remedy

If Company is unable to meet the timelines in 807 KAR 5:015 (or 807 KAR 5:015E during the period such emergency regulation is effective) for completing a survey or completing make-ready work above the Communications Space, and if Company lacks good and sufficient cause to deviate from such timelines, Operator may perform such work at its own expense using an Approved Contractor. Operator shall refer to Company's website for a list of Approved Contractors for specified purposes. Self-help is not available for pole replacements or for surveys or make-ready related to ducts. Operator shall provide written notice to Company at least one (1) week prior to performing surveys or performing make-ready above the Communications Space. Operator shall notify Company immediately if a survey or make-ready causes any property damage or an outage that is reasonably likely to interrupt Company's services.

12. One-Touch Make-Ready

For Attachments to Distribution Poles that require only "simple make-ready," as that term is defined in 807 KAR 5:015, Operator may elect to proceed with the one-touch make-ready (OTMR) process established in this Section 12, as opposed to the standard process set forth in Section 6 of this Tariff. To elect OTMR, Operator must clearly indicate in its application that it is electing the OTMR process. Operator shall not combine requests for "simple make-ready" and "complex make-ready," as those terms are defined in 807 KAR 5:015, within an OTMR application. Operator's OTMR application shall identify the "simple make-ready" that it intends to perform.

Company shall, within ten (10) days of receipt, determine whether Operator's OTMR application is complete. Upon receipt of a complete OTMR application, Company shall review such application on the merits within the timelines established by 807 KAR 5:015. If Company denies an OTMR application on the merits, Company will provide Operator with an explanation of its denial, along with information and documentation supporting Company's decision.

Operator shall be responsible for all surveys required as part of the OTMR process. Any survey performed under the OTMR process shall be conducted by an Approved Contractor. Operator shall provide Company, as well as any third parties with attachments on Distribution Poles subject to an OTMR application, at least five (5) days' advance written notice of any field inspection, and such notice shall: provide the date, time and location of the field inspection; and state the name of the Approved Contractor that will be performing the field inspection. Operator shall allow Company and affected third parties to be present for any field inspection it performs under the OTMR process.

If Operator's OTMR application is approved, Operator may, after providing fifteen (15) days' advance written notice to Company and affected third parties, proceed with the make-ready as allowed by 807 KAR 5:015. Operator's notice shall: provide the date, time and location of the make-ready; describe the make-ready involved; and identify the contractor that will be performing the make-ready. Operator shall allow Company and affected third parties to be present during the make-ready. Operator shall complete all make-ready within thirty (30) days of the date on which Company approved Operator's OTMR application (or within seventy-five (75) days in the case of a Larger Order), or else Operator's OTMR application will be deemed closed.

If Company or Operator determine at any time that make-ready does not qualify as "simple make-ready," Operator shall halt all make-ready on the impacted Distribution Poles. The make-ready on the impacted Distribution Poles shall thereafter be subject to the requirements of Section 6 of this Tariff. Operator shall notify Company and affected third parties within fifteen (15) days of completion of the make-ready identified in the OTMR application.

Continued on Sheet 12-7

Tariff P.A. Continued
(Pole Attachments)

13. Pole Inspection

Company may make periodic inspections, as conditions may warrant, for the purpose of determining compliance with the provisions of this Tariff. Company reserves the right to inspect each new or proposed installation of Operator on Company's Facilities. In addition, Company's right to make any inspections and any inspection made pursuant to such right shall not relieve Operator of any responsibility, obligation or liability assumed under this Tariff.

14. Transfer of Attachments to New Poles

Operator shall transfer its Attachments within sixty (60) days of receiving notice from Company (Transfer Period). If Operator fails to transfer its Attachments within the Transfer Period, Company may transfer the Attachments at Operator's sole risk and expense. Company may transfer Operator's Attachments prior to the expiration of the Transfer Period if an expedited transfer is necessary for safety or reliability purposes.

15. Attachment Inventory

Owner may conduct a complete field inventory for the purpose of verifying the number and location of Operator's Attachments on Company Facilities. Company shall provide Operator with at least thirty (30) days' prior notice of a field inventory, and Operator shall advise Company whether Operator desires to participate in the field inventory not less than fifteen (15) days prior to the scheduled date of such inventory. Operator shall reimburse Company for the costs Company incurs in performing the field inventory, regardless of whether Operator elects to participate in the inventory; provided, however, Company may not charge Operator for more than one (1) complete field inventory within a five (5) year period. If Company inspects the Attachments of more than one Operator during a field inventory, then each Operator whose Attachments were inspected by Company during the field inventory shall share pro rata in the costs of such inventory. Upon request, Company shall furnish a summary report for the field inventory within a reasonable time after its completion.

If a field inventory reveals that the number of Operator's Attachments exceeds the number of Attachments shown in Company's existing records, the excess number of Attachments shall be presumed to be unauthorized attachments and handled in accordance with Section 16.

16. Unauthorized Attachments

If Operator makes an Attachment that requires approval by, or advance notice to, Company under this Tariff, and if Operator fails to comply with such approval or notice requirements, then Operator's Attachment shall be deemed an unauthorized attachment. Unless Operator can demonstrate to Company's reasonable satisfaction that an unauthorized attachment was made more recently, unauthorized attachments are presumed to have existed on Company Facilities for two (2) years. Operator shall be liable for all charges and fees that would have been due under the Tariff for this time period. In addition to charges and fees applicable to the period of unauthorized attachment, Operator shall pay a penalty in the amount of: (1) $25 for each unauthorized attachment within the Communications Space on a Distribution Pole; (2) $500 for each unauthorized attachment above the Communications Space on a Distribution Pole; and (3) $500 for each unauthorized attachment within a duct. Operator shall submit an application for approval of any unauthorized attachment within sixty (60) days of discovery. If Operator fails to submit the required application or to comply with Company's application process, Company may remove the unauthorized attachment at Operator's sole risk and expense.

17. Abandonment by Operator

Operator may at any time abandon the use of a Company Facility hereunder by removing therefrom all of its Attachments and by giving written notice thereof, on a form provided by Company, and no Facility shall be considered abandoned until such notice is received. If notice has been given that Attachment(s) have been removed, but the Attachments are later discovered not to have been removed, then such Attachments shall be deemed unauthorized attachments and handled in accordance with Section 16 of this Tariff.

Continued on Sheet 12-8

Tariff P.A. Continued
(Pole Attachments)

18. Indemnity

Operator hereby agrees to indemnify, hold harmless, and defend Company from and against any and all loss, damage, cost or expense which Company may suffer or for which Company may be held liable because of interruption of Operator's service to its subscribers, or by reason of bodily injury, including death, to any person, or damage to or destruction of any property, including loss of use thereof, arising out of or in any manner connected with the attachment, operation, and maintenance of the Attachments and other facilities of Operator on the Facilities of Company under this Tariff, or to any such act or omission of Operator's respective representatives, employees, agents or contractors.

19. Limitation of Liability

IN NO EVENT SHALL COMPANY OR ANY OF ITS REPRESENTATIVES BE LIABLE UNDER THIS TARIFF TO OPERATOR FOR CONSEQUENTIAL, INDIRECT, INCIDENTAL, SPECIAL, EXEMPLARY, PUNITIVE OR ENHANCED DAMAGES, LOST PROFITS OR REVENUES OR DIMINUTION IN VALUE, ARISING OUT OF, OR RELATING TO, OR IN CONNECTION WITH THIS TARIFF, REGARDLESS OF (A) WHETHER SUCH DAMAGES WERE FORESEEABLE; (B) WHETHER OR NOT COMPANY WAS ADVISED OF THE POSSIBILITY OF SUCH DAMAGES OR (C) THE LEGAL OR EQUITABLE THEORY (CONTRACT, TORT OR OTHERWISE) UPON WHICH THE CLAIM IS BASED. THE LIMITATIONS SET FORTH IN THIS SECTION 19 SHALL NOT APPLY TO DAMAGES OR LIABILITY ARISING FROM THE GROSSLY NEGLIGENT ACTS OR OMISSIONS OR WILLFUL MISCONDUCT OF COMPANY IN PERFORMING ITS OBLIGATIONS UNDER THIS TARIFF.

20. Insurance

Operator agrees to obtain and maintain at all times policies of insurance as follows:

(a) Comprehensive bodily injury liability insurance in an amount not less than $5,000,000 for any one occurrence.
(b) Comprehensive property damage liability insurance in an amount not less than $5,000,000 for any one occurrence.
(c) Contractual liability insurance in an amount not less than the foregoing minimums to cover the liability assumed by the Operator under the agreement or indemnity set forth above.

Prior to making Attachments to Company's Facilities, Operator shall furnish to Company two copies of a certificate, from an insurance carrier licensed to do business in Kentucky, stating that policies of insurance have been issued by it to Operator providing for the insurance listed above and that such policies are in force. Such certificate shall state that the insurance carrier will give Company thirty (30) days' prior written notice of any cancellation of or material change in such policies.

21. Performance Assurance

Operator shall furnish performance assurance in the following amounts to guarantee the payment of any sums which may become due for attachment charges, inspections, or work performed by Company under this Tariff, including the removal of Attachments upon termination of any license hereunder:

Number of Attachments	Amount per Attachment	Maximum Total
1-7,500	$20	$150,000
7,501-15,000	$10	$225,000
15,001+	$5	$1,000,000

Continued on Sheet 12-9

Tariff P.A. Continued
(Pole Attachments)

The above-stated amounts are incremental. By way of example, 10,000 Attachments would require performance assurance in the amount of $175,000 ($20 per Attachment for the first 7,500 Attachments; $10 per Attachment for the next 2,500 Attachments); 20,000 Attachments would require performance assurance in the amount of $250,000 ($20 per Attachment for the first 7,500 Attachments; $10 per Attachment the next 7,500 Attachments; and $5 per Attachment for the last 5,000 Attachments).

The amount of the performance assurance shall be calculated by Company annually based on Operator's then-existing number of Attachments. Operator shall provide the performance assurance within thirty (30) days of its request by Company.
If Operator proposes to attach a Wireless Facilities to Company Facilities, Operator shall provide performance assurance in the amount of $1,500 for each Company Facility to which a Wireless Facility is attached. The amount of the performance assurance shall not be reduced upon completion of installation or other event.

In the event the Operator provides performance assurance in the form of a surety bond or letter of credit, each bond or letter of credit shall contain the provision that it shall not be terminated prior to six (6) months after Company's receipt of written notice of the desire of the bonding or insurance company, or bank, to terminate such bond or letter of credit. Company may waive this requirement if an acceptable replacement is received before the six (6) months has ended. Upon termination of such surety bond or letter of credit, Company shall request Operator to immediately remove its Attachments and all other equipment from Company Facilities. If Operator should fail to complete the removal of all of its Attachments from Company Facilities within sixty (60) days after receipt of such request, then Company may remove Operator's Attachments at Operator's expense and without liability for any damage to Operator's Attachments.

Each surety bond shall be issued by an entity having a minimum A.M. Best rating of A- (and each letter of credit shall be issued by an entity having a minimum Credit Rating of A- by S& P or A3 by Moody's at the time of issuance and at all times the relevant instrument is outstanding.

22. Easements
Operator shall secure any right, license or permit from any governmental body, authority or other person or persons which may be required for the construction or maintenance of Attachments of Operator. Company does not convey nor guarantee any easements, rights-of-way or franchises for the construction and maintenance of said Attachments. Operator hereby agrees to indemnify and save harmless Company from any and all claims, including the expenses incurred by Company to defend itself against such claims, resulting from or arising out of the failure of Operator to secure such right, license, permit or easement for the construction or maintenance of said Attachments on Company's poles.

23. Charges and Fees
Operator agrees to pay Company an annual charge per Attachment as set forth in Section 3 of this Tariff in advance, and such other charges as may be provided for herein, for the use of each of Company Facility, any portion of which is occupied by, or reserved at Operator's request for, the Attachments of Operator.

Operator agrees to reimburse Company for all reasonable non-recurring expenses caused by or attributable to Operator's initial Attachments including without limitation the amounts set forth herein. Operator further agrees to reimburse the expenses of Company in examining poles used but not owned by Company to which Operator proposes to make Attachments.

24. Fees for Additional Attachments
For Attachments made to Company Facilities between billing dates, Operator shall be billed a prorated amount of the annual charge effective on the date of attachment on the Operator's next bill. Company will not reimburse Operator for, or otherwise prorate Operator's next bill for, any Attachments removed from Company Facilities between billing dates.

Continued on Sheet 12-10

Tariff P.A. Continued
(Pole Attachments)

25. Payment

Payment of amounts due hereunder is due on the dates or at the times indicated with respect to each such payment. In the event the time for any payment is not specified, such payment shall be due thirty (30) days from the date of the invoice therefor. All amounts not so paid shall accrue interest at a monthly simple interest rate of 1.5% . Where the provisions of the Tariff require any payment by Operator to the Company other than for attachment charges, Company may, at its option, require that the estimated amount thereof be paid in advance of permission to use any pole or the performance by Company of any work. In such a case, Company may, in its sole discretion, invoice any deficiency or refund any excess to Operator after the current amount of such payment has been determined.

26. Default or Non-Compliance

If Operator fails to comply with any of the provisions of this Tariff or defaults in the performance of any of its obligations under this Tariff and fails within sixty (60) days, after written notice from Company to correct such default or non-compliance, Company may, in addition to all other remedies under this Tariff, take any one or more of the following actions: terminate the specific permit or permits covering the Company Facilities to which such default or non-compliance is applicable; remove, relocate or rearrange Attachments of Operator to which such default or non-compliance relates, all at Operator's expense; decline to permit additional Attachments hereunder until such default is cured; or in the event of any failure to pay any of the charges, fees or amounts provided in this Tariff or any other substantial default, or of repeated defaults, terminate Operator's right of attachment. Where applicable, Company's written notice of default or non-compliance shall inform Operator of Company's right to remove, relocate or rearrange Attachments of Operator, in the event Operator fails to cure its default or non-compliance within the aforementioned 60-day period. Operator shall remove all Attachments where Company has terminated the right of attachment herein within sixty (60) days of Company providing notice of termination. If Operator fails to remove such Attachments within sixty (60) days, then Company may remove such Attachments at Operator's expense. Company shall have no obligation to store or recover any value for such removed Attachments.

No liability shall be incurred by Company because of any or all such actions except for Company's gross negligence or willful misconduct in any relocation or removal of such equipment. The remedies provided herein are cumulative and in addition to any other remedies available to Company.

27. Notices

Any notice required by this Tariff shall be deemed properly given if sent to Company's or Operator's authorized representative using any of the following methods: (1) overnight delivery by nationally recognized courier; (2) certified U.S. mail, return receipt requested, postage prepaid; (3) electronically via telecopier or electronic mail; or (4) sent in the manner expressly required herein or by Company's standards. Operators shall, within thirty (30) days of the effective date of this Tariff, or if service is taken for the first time following the effective date of this Tariff, prior to submitting any applications for Attachments, provide Company with the following information for each of their authorized representatives: name, title, mailing address and electronic mailing address. The designation of an authorized representative, as well as the contact information for an existing authorized representative, may be changed at any time by similar notice. Operators are required to maintain current contact information with Company for each of their authorized representatives.

28. Prior Agreements

This Tariff, as of the effective date, terminates, supersedes and replaces any previous agreement or license affecting Company's Facilities and Operator's Attachments covered herein.

Continued on Sheet 12-11

Tariff P.A. Continued
(Pole Attachments)

29. Assignment
This Tariff shall be binding upon and inure to the benefits of the parties hereto, their respective successors and/or assigns, but Operator shall not assign, transfer or sublet any of the rights hereby granted without the prior written consent of Company, which shall not be unreasonably withheld, and any such purported assignment, transfer or subletting without such consent shall be void.

30. Performance Waiver
Neither party shall be considered in default in the performance of its obligations herein, or any of them, to the extent that performance is delayed or prevented due to causes beyond the control of said party, including but not limited to, Acts of God or the public enemy, war, revolution, civil commotion, blockade or embargo, acts of government, any law, order, proclamation, regulation, ordinance, demand, or requirement of any government, fires, explosions, cyclones, floods, unavoidable casualties, quarantine, restrictions, strikes, labor disputes, lock-outs, and other causes beyond the reasonable control of either of the parties.

31. Preservation of Remedies
No delay or omission in the exercise of any power or remedy herein provided or otherwise available to the Company shall impair or affect its right thereafter to exercise the same.

Tariff T.S.
(Temporary Service)

Availability of Service
Where capacity is available, Company will install service for temporary lighting and power service to customers who have demonstrated to the Company's satisfaction that the requested temporary service will be temporary in nature. Residential customers will be supplied with 100 amp single phase service. All other customer classes will be supplied at voltage levels applicable to the class of business.

Rate *(Tariff Code 019)*
Temporary service will be supplied under any published tariff applicable to the class of business of the Customer, when the Company has available unsold capacity of lines, transforming and generating equipment, with an additional charge of the total cost of installation, connection, disconnection and removal of service.

Charges
The same minimum charge as provided for in any applicable tariff shall be applicable to such temporary service and for not less than one full monthly minimum.

Customer's requesting temporary service will be charged a minimum temporary service installation charge, payable in advance, based on the Company's actual cost of installation, connection, disconnection, and removal of the required facilities to provide temporary service.

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-52-4.

Terms of Service
Temporary Service will be in effect for a period of 180 days from the date of installation. The Company may grant extensions based on customer's demonstration of continued need for temporary service.

The Company may discontinue temporary service at the end of the 180 days, or at the end of any extended period of time after the initial 180 days.

Special Terms and Conditions
A deposit equal to the full estimated amount of the bill and/or construction costs under this tariff may be required. This tariff is not available to customers permanently located, whose energy requirements are of a seasonal nature. See Terms and Conditions of Service.

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ISSUED BY: /s/ Tanner S. WolframBrian K. West
TITLE: Director, Regulatory ServicesVice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 2023-00159 Dated XXXX XX, XXXXJanuary 19, 2024

Tariff U.D.C.
(Underground Differential Cost Schedule)

Underground Service Plan for Residential Subdivisions and Residential Service Laterals

Applicable
To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D. 2, and R.S.D.

Rate

PRIMARY AND SECONDARY DISTRIBUTION SYSTEM

Charge: $71.15 per foot of lot width (average x number of lots) when Company performs Trenching, conduit installation, and backfilling to Company specifications.

Charge: $32.50 per foot of lot width (average x number of lots) when Customer performs trenching, conduit installation, and backfilling to Company specifications.

SERVICE LATERALS

FROM OVERHEAD FACILITIES

Charge: $32.72 per foot of trench length from Overhead Facilities when Company performs trenching, conduit installation, and backfilling to Company specifications.

Charge: $11.49 per foot of trench length from Overhead Facilities when Customer performs trenching, conduit installation, and backfilling to Company specifications.

FROM UNDERGROUND FACILITIES

Charge: $25.35 per foot of trench length from Underground Facilities when Company performs trenching, conduit installation, and backfilling to Company specifications.

Charge: $4.66 per foot of trench length from Underground Facilities when Customer performs trenching, conduit installation, and backfilling to Company specifications.

REPLACEMENT OF USEFUL OVERHEAD SERVICE DROP

Charge: $180.00 for each removal in addition to any underground differential

Rider A.F.S.
(Alternate Feed Service Rider)

Availability of Service

Standard Alternate Feed Service (AFS) is a premium service providing a redundant distribution service provided through a redundant distribution line and distribution station transformer, with automatic or manual switch-over and recovery, which provides increased reliability for distribution service. Rider AFS applies to those customers requesting new or upgraded AFS after the effective date of this rider. Rider AFS also applies to existing customers that desire to maintain redundant service when the Company must make expenditures in order to continue providing such service.

Rider AFS is available to customers who request a primary voltage alternate feed and who normally take service under Tariffs M.G.S.-TOD, L.G.S., L.G.S.-TOD, I.G.S., or M.W. for their basic service requirements, provided that the Company has adequate capacity in existing distribution facilities, as determined by the Company, or if changes can be made to make capacity available. AFS provided under this rider may not be available at all times, including emergency situations.

System Impact Study Charge

The Company shall charge the customer for the actual cost incurred by the Company to conduct a system impact study for each site reviewed. The study will consist of, but is not limited to, the following: (1) identification of customer load requirements, (2) identification of the potential facilities needed to provide the AFS, (3) determination of the impact of AFS loading on all electrical facilities under review, (4) evaluation of the impact of the AFS on system protection and coordination issues including the review of the transfer switch, (5) evaluation of the impact of the AFS request on system reliability indices and power quality, (6) development of cost estimates for any required system improvements or enhancements required by the AFS, and (7) documentation of the results of the study. The Company will provide to the customer an estimate of charges for this study.

Equipment and Installation Charge

The customer shall pay, in advance of construction, a nonrefundable amount for all equipment and installation costs for all dedicated and/or local facilities provided by the Company required to furnish either a new or upgraded AFS. The payment shall be grossed-up for federal and state taxes, assessment fees and gross receipts taxes. The customer will not acquire any title in said facilities by reason of such payment. The equipment and installation charge shall be determined by the Company and shall include, but not be limited to, the following: (1) all costs associated with the AFS dedicated and/or local facilities provided by the Company and (2) any costs or modifications to the customer's basic service facilities.

The customer is responsible for all costs associated with providing and maintaining phone service for use with metering to notify the Company of a transfer of service to the AFS or return to basic service.

Transfer Switch Provision

In the event the customer receives basic service at primary voltage, the customer shall install, own, maintain, test, inspect, operate and replace the transfer switch. Customer-owned switches are required to be at primary voltage and must meet the Company's engineering, operational and maintenance specifications. The Company reserves the right to inspect the customer-owned switches periodically and to disconnect the AFS for adverse impacts on reliability or safety.

Existing AFS customers, who receive basic service at primary voltage and are served via a Company-owned transfer switch and control module, may elect for the Company to continue ownership of the transfer switch. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, the customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer shall pay a monthly rate of $15.75 for the Company to annually test the transfer switch / control module and the customer shall reimburse the Company for the actual costs involved in maintaining the Company-owned transfer switch and control module.

Continued on Sheet 15-2

Rider A.F.S. Continued
(Alternate Feed Service Rider)

Transfer Switch Provision Continued

In the event a customer receives basic service at secondary voltage and requests AFS, the Company will provide the AFS at primary voltage. The Company will install, own, maintain, test, inspect and operate the transfer switch and control module. The customer shall pay the Company a nonrefundable amount for all costs associated with the transfer switch installation. The payment shall be grossed-up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer is required to pay the monthly rate for testing and ongoing maintenance costs defined above. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes.

After a transfer of service to the AFS, a customer utilizing a manual or semi-automatic transfer switch shall return to the basic service within one (1) week or as mutually agreed to by the Company and customer. In the event system constraints require a transfer to be expedited, the Company will endeavor to provide as much advance notice as possible to the customer. However, the customer shall accomplish the transfer back to the basic service within ten minutes if notified by the Company of system constraints. In the event the customer fails to return to basic service within 12 hours, or as mutually agreed to by the Company and customer, or within ten minutes of notification of system constraints, the Company reserves the right to immediately disconnect the customer's load from the AFS source. If the customer does not return to the basic service as agreed to, or as requested by the Company, the Company may also provide 30 days' notice to terminate the AFS agreement with the customer.

The customer shall make a request to the Company for approval three days in advance for any planned switching.

Monthly AFS Capacity Reservation Demand Charge
Monthly AFS charges will be in addition to all monthly basic service charges paid by the customer under the applicable tariff.

The Monthly AFS Capacity Reservation Demand Charge for the reservation of distribution station and primary lines is $6.38 per kW.

AFS Capacity Reservation
The customer shall reserve a specific amount of AFS capacity equal to, or less than, the customer's average maximum requirements, but in no event shall the customer's AFS capacity reservation under this rider exceed the capacity reservation for the customer's basic service under the appropriate tariff. The Company shall not be required to supply AFS capacity in excess of that reserved except by mutual agreement.

If the customer plans to increase the AFS demand at anytime in the future, the customer shall promptly notify the Company of such additional demand requirements. The customer's AFS capacity reservation and billing will be adjusted accordingly. The customer will pay the Company the actual costs of any and all additional dedicated and/or local facilities required to provide AFS in advance of construction and pursuant to an AFS construction agreement. If customer exceeds the agreed upon AFS capacity reservation, the Company reserves the right to disconnect the AFS. If the customer's AFS metered demand exceeds the agreed upon AFS capacity reservation, which jeopardizes company facilities or the electrical service to other customers, the Company reserves the right to disconnect the AFS immediately. If the Company agrees to allow the customer to continue AFS, the customer will be required to sign a new AFS agreement reflecting the new AFS capacity reservation. In addition, the customer will promptly notify Kentucky Power regarding any reduction in the AFS capacity reservation.

Continued on Sheet 15-3

Rider A.F.S. Continued
(Alternate Feed Service Rider)

The customer may reserve partial-load AFS capacity, which shall be less than the customer's full requirements for basic service subject to the conditions in this provision. Prior to the customer receiving partial-load AFS capacity, the customer shall be required to demonstrate or provide evidence to the Company that they have installed demand-controlling equipment that is capable of curtailing load when a switch has been made from the basic service to the AFS. The Company reserves the right to test and verify the customer's ability to curtail load to meet the agreed upon partial-load AFS capacity reservation.

Determination of Billing Demand

Full-Load Requirement:

For customers requesting AFS equal to their load requirement for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly billing demand on the AFS during the past 11 months, or (c) the customer's basic service capacity reservation, or (d) the customer's highest previously established monthly billing demand on the basic service during the past 11 months.

Partial-Load Requirement:

For customers requesting partial-load AFS capacity reservation that is less than the customer's full requirements for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak on the AFS as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly metered demand on the partial-load AFS during the past 11 months.

Delayed Payment Charge

Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-52-4.

Terms of Contract

The AFS agreement under this rider will be made for a period of not less than one year and shall remain in effect thereafter until either party shall give at least six months' written notice to the other of the intention to discontinue service under the terms of this rider.

Disconnection of AFS under this rider due to reliability or safety concerns associated with customer-owned transfer switches will not relieve the customer of payments required hereunder for the duration of the agreement term.

Special Terms and Conditions

This rider is subject to the Company's Terms and Conditions of Service.

Upon receipt of a request from the customer for non-standard AFS (AFS which includes unique service characteristics different from standard AFS), the Company will provide the customer with a written estimate of all costs, including system impact study costs, and any applicable unique terms and conditions of service related to the provision of the non-standard AFS. An AFS agreement will be filed with the Commission under the 30-day filing procedures. The AFS agreement shall provide full disclosure of all rates, terms and conditions of service under this rider, and any and all agreements related thereto.

The Company will have sole responsibility for determining the basic service circuit and the AFS circuit.

The Company assumes no liability should the AFS circuit, transfer switch, or other equipment required to provide AFS fail to operate as designed, is unsatisfactory, or is not available for any reason.

Rider R.P.O.
(Renewable Power Option Rider)

Availability of Service

Available to customers taking metered service under the Company's R.S., R.S.D. , R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., and M.W. tariffs.

Participation in this program under Option A may be limited by the ability of the Company to procure renewable energy certificates (RECs) from Renewable Resources. If the total of all kWh under contract under this Rider equals or exceeds the Company's ability to procure RECs, the Company may suspend the availability of this Rider to new participants.

Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand.

Conditions of Service

Customers who wish to support the development of electricity generated by Renewable Resources may under Option A contract to purchase each month a specific number of fixed kWh blocks, or choose to cover all of their monthly usage.

Renewable Resources shall be defined as Wind, Solar Photovoltaic, Biomass Co-Firing of Agricultural crops and all energy crops, Hydro (as certified by the Low Impact Hydro Institute), Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-Firing of All Woody Waste including mill residue, but excluding painted or treated lumber. All REC's purchased under Option A of this tariff shall be retained or retired by the Company on behalf of customers.

Rates

Option A

In addition to the monthly charges determined according to the Company's tariff under which the customer takes metered service, the customer shall also pay the following rate for the REC option of their choosing. The charge will be applied to the customer's bill as a separate line item.

The Company will provide customers at least 30-days' advance notice of any change in the Rate. At such time, the customer may modify or cancel their automatic monthly purchase agreement. Any cancellation will be effective at the end of the current billing period when notice is provided.

	Block Purchase Charge ($ per 100 kWh block)	**All Usage Purchase Charge per kWh consumed**
A1. Solar RECs	$0.50/month	$0.005
A2. Wind RECs	$0.50/month	$0.005
A3. Hydro & Other RECs	$0.50/month	$0.005

Option B

Charges for service under option B of this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the firm service rates otherwise available to the Customer and the cost of the renewable energy resource being directly contracted for by the Customer.

Continued on Sheet 16-2

Rider R.P.O. Continued
(Renewable Power Option Rider)

Term
This is a voluntary program.

Under Option A Customers may participate through a one-time purchase, or establish an automatic monthly purchase agreement. Any payments under this program are nonrefundable. Customers participating under Option A may terminate service under this Rider by notifying the Company with at least thirty (30) days prior notice.

Under Option B, the term of the agreement will be determined in the written agreement between the Company and the Customer.

Special Terms and Conditions
This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. The Company may deny or terminate service under this Rider to customers who are delinquent in payment to the Company.

Funds collected under this Renewable Power Option Rider will be used solely to purchase RECs for the program.

Tariff N.U.G.
(Non-Utility Generator)

Availability of Service
This tariff is unavailable to new participants. This tariff is applicable to customers with generation facilities which have a total design capacity of over 1,000 kW that intends to schedule, deliver and sell the net electric output of the facility at wholesale, and who require Station Power service from the Company.

Service to any load that is electrically isolated from the Customer's generator shall be separately metered and provided in accordance with the generally available demand-metered tariff appropriate for such service to the Customer.

This tariff is not available for standby, backup, maintenance, or supplemental service for wholesale or retail loads served by Customer's generator.

Definitions

Station Power - The electrical energy and capacity supplied to the customer to serve the auxiliary loads at the Customer's generation facilities, usually when the Customer's generator is not operating. Station Power does not include Startup Power.

Station Power Service
Customers requiring Station Power shall take service under the generally available demand-metered tariff appropriate for the Customer's Station Power requirements.

Station Contract Capacity – The Customer shall contract for a definite amount of electrical capacity in kW sufficient to meet the maximum Station Power requirements that the Company is expected to supply under the generally available demand-metered tariff appropriate for the customer.

Transmission Service

Transmission Provider - The entity providing transmission service to customers in the Company's service territory. Such entity may be the Company or a regional transmission entity.

Prior to taking service under this tariff, the Customer must have a fully executed Interconnection and Operation Agreement with the Company and/or the Transmission Provider or an unexecuted agreement filed with the Federal Energy Regulatory Commission under applicable procedures.

Transmission Congestion is the condition that exists when market participants seek to dispatch in a pattern that would result in power flows that cannot be physically accommodated by the system.

Term of Contract
Contracts under this tariff will be made for an initial period of not less than one year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than one year.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

Continued on Sheet 17-2

Tariff N.U.G. Continued
(Non-Utility Generator)

The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement. Contracts will be made in multiples of 100 kW.

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-52- 4.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff shall not obligate the Company to purchase or pay for any capacity or energy produced by the Customer's generator.

Customers desiring to provide Station Power from other generation facilities, owned by the same individual business entity that are not located on the site of the customer's generator (remote self-supply), shall take service under the terms and conditions contained within the applicable Open Access Transmission Tariff as filed with and accepted by the Federal Energy Regulatory Commission.

Tariff N.M.S.
(Net Metering Service)

Availability of Service

Net Metering is available to eligible customer-generators in the Company's service territory, upon request, and on a first-come, first-served basis up to a cumulative capacity of one percent (1%) of the Company's single hour peak load in Kentucky during the previous year. If the cumulative generating capacity of net metering systems reaches 1% of the Company's single hour peak load during the previous year, upon Commission approval, the Company's obligation to offer net metering to a new customer-generator may be limited. An eligible customer- generator shall mean a retail electric customer of the Company with a generating facility that:

(1) Generates electricity using solar energy, wind energy, biomass or biogas energy, or hydro energy;
(2) Has a rated capacity of not greater than forty-five (45) kilowatts;
(3) Is located on the customer's premises;
(4) Is owned and operated by the customer;
(5) Is connected in parallel with the Company's electric distribution system; and
(6) Has the primary purpose of supplying all or part of the customer's own electricity requirements.

At its sole discretion, the Company may provide Net Metering to other customer-generators not meeting all the conditions listed above on a case-by-case basis.

Eligible electric generating facilities in service before May 15, 2021 shall be entitled to continue to take service under this tariff, as it may be amended from time to time by the Commission, until the earlier of: (i) May 14, 2046; or (ii) the date the customer's modification of the eligible electric generating facility results in a material increase in the eligible electric generating facility's capacity.

The term "Customer" hereinafter shall refer to any customer requesting or receiving Net Metering services under this tariff.

Metering

Net energy metering shall be accomplished using a standard kilowatt-hour meter capable of measuring the flow of electricity in two (2) directions. If the existing electrical meter installed at the customer's facility is not capable of measuring the flow of electricity in two directions, the Company will provide the customer with the appropriate metering at no additional cost to the customer. If the customer requests any additional meter or meters or if distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

Billing/Monthly Charges

Monthly charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility. Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non- energy charge portions of the standard tariff bill. If the customer's net energy is negative during a billing period, the customer shall be credited in the next billing period for the kWh difference. If time-of-day metering is used, energy flows in both directions shall be netted and accounted for at the specific time-of-use in accordance with the provisions of the customer's standard tariff and this Net Metering Service Tariff. When the customer elects to no longer take service under this Net Metering Service Tariff, any unused credit shall revert to the Company. Excess electricity credits are not transferable between customers or locations.

Continued on Sheet 18-2

Tariff N.M.S. Continued
(Net Metering Service)

Application and Approval Process

The Customer shall submit an Application for Interconnection and Net Metering ("Application") and receive approval from the Company prior to connecting the generator facility to the Company's system.

Applications will be submitted by the Customer and reviewed and processed by the Company according to either Level 1 or Level 2 processes defined below.

The Company may reject an Application for violations of any code, standard, or regulation related to reliability or safety; however, the Company will work with the Customer to resolve those issues to the extent practicable.

Customers may contact the Company to check on the status of an Application or with questions prior to submitting an Application. Company contact information can be found on Kentucky Power Company's Application Form or on the Company's website.

Level 1 and Level 2 Definitions

Level 1

A Level 1 Application shall be used if the generating facility is inverter-based and is certified by a nationally recognized testing laboratory to meet the requirements of Underwriters Laboratories Standard 1741 "Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources" (UL 1741).

The Company will approve the Level 1 Application if the generating facility also meets all of the following conditions:

(1) For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
(2) If the proposed generating facility is to be interconnected on a single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generating facility, will not exceed the smaller of 20 kVA or the nameplate rating of the transformer.
(3) If the proposed generating facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.
(4) If the generating facility is to be connected to three-phase, three wire primary Company distribution lines, the generator shall appear as a phase-to-phase connection at the primary Company distribution line.
(5) If the generating facility is to be connected to three-phase, four wire primary Company distribution lines, the generator shall appear to the primary Company distribution line as an effectively grounded source.
(6) The interconnection will not be on an area or spot network.
(7) The Company does not identify any violations of any applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems."
(8) No construction of facilities by the Company on its own system will be required to accommodate the generating facility.

Continued on Sheet 18-3

Tariff N.M.S. Continued
(Net Metering Service)

Level 1 Continued
If the generating facility does not meet all of the above listed criteria, the Company, in its sole discretion, may either: 1) approve the generating facility under the Level 1 Application if the Company determines that the generating facility can be safely and reliably connected to the Company's system; or 2) deny the Application as submitted under the Level 1 Application.

The Company shall notify the customer within 20 business days whether the Application is approved or denied, based on the criteria provided in this section.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the time to process the Application.

When approved, the Company will indicate by signing the approval line on the Level 1 Application Form and returning it to the customer. The approval will be subject to successful completion of an initial installation inspection and witness test if required by the Company. The Company's approval section of the Application will indicate if an inspection and witness test are required. If so, the customer shall notify the Company within 3 business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within 10 business days of completion of the generator facility installation or as otherwise agreed to by the Company and the customer. The customer may not operate the generating facility until successful completion of such inspection and witness test, unless the Company expressly permits operational testing not to exceed two hours. If the installation fails the inspection or witness test due to noncompliance with any provision in the Application and Company approval, the customer shall not operate the generating facility until any and all noncompliance is corrected and re-inspected by the Company.

If the Application is denied, the Company will supply the customer with reasons for denial. The customer may resubmit under Level 2 if appropriate.

Level 2
A Level 2 Application is required under any of the following:

(1) The generating facility is not inverter based;
(2) The generating facility uses equipment that is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741; or
(3) The generating facility does not meet one or more of the additional conditions under Level 1.

The Company will approve the Level 2 Application if the generating facility meets the Company's technical interconnection requirements, which are based on IEEE 1547. The Company shall make its technical interconnection requirements available online and upon request.

The Company will process the Level 2 Application within 30 business days of receipt of a complete Application. Within that time the Company will respond in one of the following ways:

Continued on Sheet 18-4

Tariff N.M.S. Continued
(Net Metering Service)

(1) The Application is approved and the Company will provide the customer with an Interconnection Agreement to sign.
(2) If construction or other changes to the Company's distribution system are required, the cost will be the responsibility of the customer. The Company will give notice to the customer and offer to meet to discuss estimated costs and construction timeframe. Should the customer agree to pay for costs and proceed, the Company will provide the customer with an Interconnection Agreement to sign within a reasonable time.
(3) The Application is denied. The Company will supply the customer with reasons for denial and offer to meet to discuss possible changes that would result in Company approval. Customer may resubmit Application with changes.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the 30-business-day target to process the Application.

The Interconnection Agreement will contain all the terms and conditions for interconnection consistent with those specified in this tariff, inspection and witness test requirements, description of and cost of construction or other changes to the Company's distribution system required to accommodate the generating facility, and detailed documentation of the generating facilities which may include single line diagrams, relay settings, and a description of operation.

The customer may not operate the generating facility until an Interconnection Agreement is signed by the customer and Company and all necessary conditions stipulated in the agreement are met.

Application, Inspection and Processing Fees
No application fee or other review, study, or inspection or witness test fees will be charged by the company for Level I application.

The Company will require each customer to submit with each Level 2 Application a non-refundable application, inspection and processing fee of $50. In the event the Company determines an impact study is necessary with respect to a Level 2 Application, the customer shall be responsible for any reasonable costs up to $1,000 for the initial impact study. The Company shall provide documentation of the actual cost of the impact study. Any other studies requested by the customer shall be at the customer's sole expense.

Terms and Conditions for Interconnection
To interconnect to the Company's distribution system, the customer's generating facility shall comply with the following terms and conditions:

(1) The Company shall provide the customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

(2) The customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance and safe operation of the generating facility. Upon reasonable request from the Company, the customer shall demonstrate generating facility compliance.

Continued on Sheet 18-5

Tariff N.M.S. Continued
(Net Metering Service)

Terms and Conditions for Interconnection Continued

(3) The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by IEEE and accredited testing laboratories such as Underwriters Laboratories; (b) the NEC as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

(4) Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

(5) Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

(6) Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(7) After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance, and operation of the generating facility comply with the requirements of this tariff.

Continued on Sheet 18-6

Tariff N.M.S. Continued
(Net Metering Service)

Terms and Conditions for Interconnection Continued

(8) For Level 1 and 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring that the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

(9) Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability, or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

(10) Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity is allowed without approval.

(11) To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining, or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

Continued on Sheet 18-7

Tariff N.M.S. Continued
(Net Metering Service)

Terms and Conditions for Interconnection Continued

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

(12) The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for both Level 1 and Level 2 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

(13) By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

(14) A customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

(15) The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Term of Contract

Any contract required under this tariff shall become effective when executed by both parties and shall continue in effect until terminated. The contract may be terminated as follows: (a) Customer may terminate the contract at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the contract or the rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service and all provisions of the standard service tariff under which the customer takes service. This tariff is also subject to the applicable provisions of the Company's Technical Requirements for Interconnection.

Continued on Sheet 18-8

Tariff N.M.S. Continued
(Net Metering Service)

Application For Interconnection And Net Metering – Level 1

Use this Application only for: 1.) a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741, 2.) less than or equal to 45 kW generation capacity and 3.) connecting to Kentucky Power distribution system.

Submit this Application to:

D.G. Coordinator
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoordinator@aep.com

(Contact person listed is subject to change. Please visit our website for up-to date information http://www.kentucky power.com)

Applicant

Name:

Mailing Address:

City: State: Zip:

Phone: ( ) Phone: ( )

E-mail address:

Service Location

Name:

Street Address:

City: State: Zip: Electric Service

Account Number

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Alternate Contacts

Name	Company	Telephone/Email

Continued on Sheet 18-9

Tariff N.M.S. Continued
(Net Metering Service)

APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 1 – CONTINUED

Equipment Qualifications

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Inverter Manufacturer: Model:

Inverter Power Rating: Voltage Rating:

Power Rating of Energy Source (i.e., solar panels, wind turbine):

Battery Storage: ( ) Yes ( ) No If Yes, Battery Power Rating:

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: _____

Continued on Sheet 18-10

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1:

1 Kentucky Power Company (Company) shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

6 Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

Continued on Sheet 18-11

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 1 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity is allowed without approval.

Continued on Sheet 18-12

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for Level 1 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the Customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Continued on Sheet 18-13

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued
Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute. I hereby certify that, to the best of my knowledge, all of the information provided in this Application is true, and I agree to abide by all the Terms and Conditions included in this Application for Interconnection and Net Metering and Company's Net Metering Tariff.

Customer Signature: _____ **Date:** _____

COMPANY APPROVAL SECTION

When signed below by a Company representative, Application for Interconnection and Net Metering is approved subject to the provisions contained in this Application and as indicated below.

Company inspection and witness test: ( ) Required ( ) Waived

If Company inspection and witness test is required, Customer shall notify the Company within three (3) business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within ten (10) business days of completion of the generating facility installation or as otherwise agreed to by the Company and the Customer. Unless indicated below, the Customer may not operate the generating facility until such inspection and witness test is successfully completed. Additionally, the Customer may not operate the generating facility until all other terms and conditions in the Application have been met.
Call: _____ to schedule an inspection and witness test.

Pre-Inspection operational testing not to exceed two (2) hours: ( ) Allowed ( ) Not Allowed

If Company inspection and witness test is waived, operation of the generating facility may begin when installation is complete, and all other terms and conditions in the Application have been met.

Additions, Changes, or Clarifications to Application Information: ( ) None ( ) As specified here:

Approved by: _____ **Date**: _____

Printed Name: _____ **Title:** _____

Continued on Sheet 18-14

Tariff N.M.S. Continued
(Net Metering Service)

Application for Interconnection and Net Metering – Level 2

Use this Application form for connecting to the Kentucky Power distribution system and: 1.) the generating facility is not inverter based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or 2.) does not meet any of the additional conditions under a Level 1 Application (inverter based and less than or equal to 45kW generation).

Submit this Application (along with the application fee of $100) to:

D.G. Coordinator
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoordinator@aep.com

(Contact person listed is subject to change. Please visit our website for up-to date information http://www.kentucky power.com)

Applicant

Name:		
Mailing Address:		
City:	State:	Zip:
Phone: ( )		Phone: ( )
E-mail address:		

Service Location

Name:		
Street Address:		
City:	State:	Zip:
Electric Service Account Number		

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Alternate Contacts

Name	Company	Telephone/Email

Continued on Sheet 18-15

Tariff N.M.S. Continued
(Net Metering Service)

APPPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 2 - CONTINUED

Equipment Qualifications

Total Generating Capacity (kW) of the Generating Facility: _____

Type of Generator: ( ) Inverter-Based ( ) Synchronous ( ) Induction

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: _____

Continued on Sheet 18-16

Tariff N.M.S. Continued
(Net Metering Service)

Interconnection Agreement – Level 2

This Interconnection Agreement (Agreement) is made and entered into this _____ day of ___, 20__, by and between Kentucky Power Company (Company), and _____ (Customer). Company and Customer are hereinafter sometimes referred to individually as "Party" or collectively as "Parties"

Witnesseth:

Whereas, Customer is installing, or has installed, generating equipment, controls, and protective relays and equipment (Generating Facility) used to interconnect and operate in parallel with Company's electric system, which Generating Facility is more fully described in Exhibit A, attached hereto and incorporated herein by this Agreement, and as follows:

Location: _____

Generator Size and Type:

_____

Now, Therefore, in consideration thereof, Customer and Company agree as follows:

Company agrees to allow Customer to interconnect and operate the generating Facility in parallel with the Company's electric system and Customer agrees to abide by Company's Net Metering Tariff and all Terms and Conditions listed in this Agreement including any additional conditions listed in Exhibit A.

Continued on Sheet 18-17

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2:

To interconnect to the Kentucky Power Company (Company) distribution system, the customer's generating facility shall comply with the following terms and conditions:

1. Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter/meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2. Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3. The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4. Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5. Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

Continued on Sheet 18-18

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

6. Customer shall be responsible for protecting, at Customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

7. After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8. For Level 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

   The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

Continued on Sheet 18-19

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

10. Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components not resulting in increases in generating facility capacity is allowed without approval.

11. To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

    The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12. The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy). Customer shall provide Company with proof of such insurance at the time that application is made for net metering.

13. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15. The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Continued on Sheet 18-20

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

IN WITNESS WHEREOF, the Parties have executed this Agreement, effective as of the date first above written.

Customer Signature:	_____	**Date:**	_____
Printed Name:	_____	**Title:**	_____
Company Signature:	_____	**Date:**	_____
Printed Name:	_____	**Title:**	_____

Continued on Sheet 18-21

Tariff N.M.S. Continued
(Net Metering Service)

Interconnection Agreement – Level 2
Exhibit A

- Exhibit A will contain additional detailed information about the Generating Facility such as a single line diagram, relay settings, and a description of operation.
- When construction of the Company's facilities is required, Exhibit A will also contain a description and associated cost.
- Exhibit A will also specify requirements for a Company inspection and witness test and when limited operation for testing or full operation may begin.

Tariff N.M.S. II
(Net Metering Service II)

Availability of Service

Net Metering is available to eligible customer-generators in the Company's service territory, upon request, and on a first-come, first-served basis up to a cumulative capacity of one percent (1%) of the Company's single hour peak load in Kentucky during the previous year. If the cumulative generating capacity of net metering systems reaches 1% of the Company's single hour peak load during the previous year, upon Commission approval, the Company's obligation to offer net metering to a new customer-generator may be limited. An eligible customer- generator shall mean a retail electric customer of the Company with a generating facility that:

(1) Generates electricity using solar energy, wind energy, biomass or biogas energy, or hydro energy;
(2) Has a rated capacity of not greater than forty-five (45) kilowatts;
(3) Is located on the customer's premises;
(4) Is owned and operated by the customer;
(5) Is connected in parallel with the Company's electric distribution system; and
(6) Has the primary purpose of supplying all or part of the customer's own electricity requirements.

At its sole discretion, the Company may provide Net Metering to other customer-generators not meeting all the conditions listed above on a case-by-case basis.

Eligible generating facilities may take service, for a period of 25 years after the eligible generating facility is first placed in service, under the two-part rate structure and netting periods of this tariff in effect at the time the eligible electric generating facility is first placed in service.

Customers served under this optional offering will not be eligible for the Company's Equal Payment Plan (Budget) or Average Monthly Payment Plan (AMP).

The term "Customer" hereinafter shall refer to any customer requesting or receiving Net Metering services under this tariff.

Metering

Net energy metering shall be accomplished using a time of use ("TOU") kilowatt-hour meter capable of measuring the flow of electricity in two (2) directions. If the existing electrical meter installed at the customer's facility is not capable of measuring the flow of electricity in two directions, the Company will provide the customer with the appropriate metering at no additional cost to the customer. If the customer requests any additional meter or meters or if distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

Billing Charges

All net billing kWh and kW in each netting period, accumulated for the billing period, shall be charged at the rates applicable under the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility.

Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non- energy charge portions of the standard tariff bill.

All excess customer generation, (net negative energy or "NNE"), accumulated for the billing period, shall be credited at the avoided cost rate of 0.09746 $/kWh for Residential service and 0.09657 $/kWh for non-residential service each billing period.

Continued on Sheet 19-2

Tariff N.M.S. II Continued
(Net Metering Service II)

Bill credits to customers for NNE at the avoided cost rate each billing period is a purchased power expense and shall be recovered from all customers through the Company's Purchased Power Adjustment Rider. If the NNE credit exceeds the customer's billed energy charges, along with any riders that are based on a per kWh charge, during the billing period, the amount in excess will be carried over for use in subsequent billing periods. Excess electricity credits are not transferable between customers or locations. When the customer elects to no longer take service under this Net Metering Service II Tariff, any unused credit shall revert to the Company.

Application and Approval Process

The Customer shall submit an Application for Interconnection and Net Metering ("Application") and receive approval from the Company prior to connecting the generator facility to the Company's system.

Applications will be submitted by the Customer and reviewed and processed by the Company according to either Level 1 or Level 2 processes defined below.

The Company may reject an Application for violations of any code, standard, or regulation related to reliability or safety; however, the Company will work with the Customer to resolve those issues to the extent practicable.

Customers may contact the Company to check on the status of an Application or with questions prior to submitting an Application. Company contact information can be found on Kentucky Power Company's Application Form or on the Company's website.

Level 1 and Level 2 Definitions

Level 1

A Level 1 Application shall be used if the generating facility is inverter-based and is certified by a nationally recognized testing laboratory to meet the requirements of Underwriters Laboratories Standard 1741 "Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources" (UL 1741).

The Company will approve the Level 1 Application if the generating facility also meets all of the following conditions:

(1) For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
(2) If the proposed generating facility is to be interconnected on a single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generating facility, will not exceed the smaller of 20 kVA or the nameplate rating of the transformer.
(3) If the proposed generating facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.
(4) If the generating facility is to be connected to three-phase, three wire primary Company distribution lines, the generator shall appear as a phase-to-phase connection at the primary Company distribution line.
(5) If the generating facility is to be connected to three-phase, four wire primary Company distribution lines, the generator shall appear to the primary Company distribution line as an effectively grounded source.
(6) The interconnection will not be on an area or spot network.

Continued on Sheet 19-3

Tariff N.M.S. II Continued
(Net Metering Service II)

Level 1 Continued

(7) The Company does not identify any violations of any applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems."
(8) No construction of facilities by the Company on its own system will be required to accommodate the generating facility.

If the generating facility does not meet all of the above listed criteria, the Company, in its sole discretion, may either: 1) approve the generating facility under the Level 1 Application if the Company determines that the generating facility can be safely and reliably connected to the Company's system; or 2) deny the Application as submitted under the Level 1 Application.

The Company shall notify the customer within 20 business days whether the Application is approved or denied, based on the criteria provided in this section.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the time to process the Application.

When approved, the Company will indicate by signing the approval line on the Level 1 Application Form and returning it to the customer. The approval will be subject to successful completion of an initial installation inspection and witness test if required by the Company. The Company's approval section of the Application will indicate if an inspection and witness test are required. If so, the customer shall notify the Company within 3 business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within 10 business days of completion of the generator facility installation or as otherwise agreed to by the Company and the customer. The customer may not operate the generating facility until successful completion of such inspection and witness test, unless the Company expressly permits operational testing not to exceed two hours. If the installation fails the inspection or witness test due to noncompliance with any provision in the Application and Company approval, the customer shall not operate the generating facility until any and all noncompliance is corrected and re-inspected by the Company.

If the Application is denied, the Company will supply the customer with reasons for denial. The customer may resubmit under Level 2 if appropriate.

Level 2
A Level 2 Application is required under any of the following:

(1) The generating facility is not inverter based;
(2) The generating facility uses equipment that is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741; or
(3) The generating facility does not meet one or more of the additional conditions under Level 1.

The Company will approve the Level 2 Application if the generating facility meets the Company's technical interconnection requirements, which are based on IEEE 1547. The Company shall make its technical interconnection requirements available online and upon request.

The Company will process the Level 2 Application within 30 business days of receipt of a complete Application. Within that time the Company will respond in one of the following ways:

Continued on Sheet 19-4

Tariff N.M.S. II Continued
(Net Metering Service II)

Level 2 Continued

(1) The Application is approved and the Company will provide the customer with an Interconnection Agreement to sign.
(2) If construction or other changes to the Company's distribution system are required, the cost will be the responsibility of the customer. The Company will give notice to the customer and offer to meet to discuss estimated costs and construction timeframe. Should the customer agree to pay for costs and proceed, the Company will provide the customer with an Interconnection Agreement to sign within a reasonable time.
(3) The Application is denied. The Company will supply the customer with reasons for denial and offer to meet to discuss possible changes that would result in Company approval. Customer may resubmit Application with changes.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the 30-business-day target to process the Application.

The Interconnection Agreement will contain all the terms and conditions for interconnection consistent with those specified in this tariff, inspection and witness test requirements, description of and cost of construction or other changes to the Company's distribution system required to accommodate the generating facility, and detailed documentation of the generating facilities which may include single line diagrams, relay settings, and a description of operation.

The customer may not operate the generating facility until an Interconnection Agreement is signed by the customer and Company and all necessary conditions stipulated in the agreement are met.

Application, Inspection and Processing Fees

No application fee or other review, study, or inspection or witness test fees will be charged by the Company for Level 1 applications.

The Company will require each customer to submit with each Level 2 Application a non-refundable application, inspection and processing fee of $100. In the event the Company determines an impact study is necessary with respect to a Level 2 Application, the customer shall be responsible for any reasonable costs up to $1,000 for the initial impact study. The Company shall provide documentation of the actual cost of the impact study. Any other studies requested by the customer shall be at the customer's sole expense.

Terms and Conditions for Interconnection

To interconnect to the Company's distribution system, the customer's generating facility shall comply with the following terms and conditions:

(1) The Company shall provide the customer net metering services, without charge for standard TOU metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

(2) The customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance and safe operation of the generating facility. Upon reasonable request from the Company, the customer shall demonstrate generating facility compliance.

Continued on Sheet 19-5

Tariff N.M.S. II Continued
(Net Metering Service II)

Terms and Conditions for Interconnection Continued

(3) The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by IEEE and accredited testing laboratories such as Underwriters Laboratories; (b) the NEC as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

(4) Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

(5) Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

(6) Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(7) After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance, and operation of the generating facility comply with the requirements of this tariff.

Continued on Sheet 19-6

Tariff N.M.S. II Continued
(Net Metering Service II)

Terms and Conditions for Interconnection Continued

(8) For Level 1 and 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring that the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

(9) Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability, or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

(10) Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity are allowed without approval.

(11) To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining, or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

Continued on Sheet 19-7

Tariff N.M.S. II Continued
(Net Metering Service II)

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

(12) The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for both Level 1 and Level 2 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

(13) By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

(14) A customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

(15) The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Term of Contract

Any contract required under this tariff shall become effective when executed by both parties and shall continue in effect until terminated. The contract may be terminated as follows: (a) Customer may terminate the contract at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the contract or the rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service and all provisions of the standard service tariff under which the customer takes service. This tariff is also subject to the applicable provisions of the Company's Technical Requirements for Interconnection.

Continued on Sheet 19-8

Tariff N.M.S. II Continued
(Net Metering Service II)

Application For Interconnection And Net Metering – Level 1

Use this Application only for: 1.) a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741, 2.) less than or equal to 45 kW generation capacity, and 3.) connecting to Kentucky Power distribution system.

Submit this Application to:

D.G. Coordinator American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoodinator@aep.com

(Contact person listed is subject to change. Please visit our website for up-to-date information http://www.kentuckypower.com)

Applicant

Name:

Mailing Address:

City: State: Zip:

Phone: ( ) Phone: ( )

E-mail address:

Service Location

Name:

Street Address:

City: State: Zip:

Electric Service Account Number

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Alternate Contacts

Name	Company	Telephone/Email

Continued on Sheet 19-9

Tariff N.M.S. II Continued
(Net Metering Service II)

APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 1 – CONTINUED

Equipment Qualifications

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Inverter Manufacturer: Model:

Inverter Power Rating: Voltage Rating:

Power Rating of Energy Source (i.e., solar panels, wind turbine):

Battery Storage: ( ) Yes ( ) No If Yes, Battery Power Rating:

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: _____

Continued on Sheet 19-10

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1:

1 The Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

6 Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

Continued on Sheet 19-11

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1, continued

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 1 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity are allowed without approval.

Continued on Sheet 19-12

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1, continued

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for Level 1 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the Customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits ("RECs") that may be generated by their generating facility.

Continued on Sheet 19-13

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute. I hereby certify that, to the best of my knowledge, all of the information provided in this Application is true, and I agree to abide by all the Terms and Conditions included in this Application for Interconnection and Net Metering and Company's Net Metering Tariff.

Customer Signature: _____ **Date:** _____

COMPANY APPROVAL SECTION

When signed below by a Company representative, Application for Interconnection and Net Metering is approved subject to the provisions contained in this Application and as indicated below.

Company inspection and witness test: ( ) Required ( ) Waived

If Company inspection and witness test is required, Customer shall notify the Company within three (3) business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within ten (10) business days of completion of the generating facility installation or as otherwise agreed to by the Company and the Customer. Unless indicated below, the Customer may not operate the generating facility until such inspection and witness test is successfully completed. Additionally, the Customer may not operate the generating facility until all other terms and conditions in the Application have been met.
Call: to schedule an inspection and witness test.

Pre-Inspection operational testing not to exceed two (2) hours: ( ) Allowed ( ) Not Allowed

If Company inspection and witness test is waived, operation of the generating facility may begin when installation is complete, and all other terms and conditions in the Application have been met.

Additions, Changes, or Clarifications to Application Information: ( ) None ( ) As specified here:

_____

Approved by: _____ **Date**: _____

Printed Name: _____ **Title:** _____

Continued on Sheet 19-14

Tariff N.M.S. II Continued
(Net Metering Service II)

Application for Interconnection and Net Metering – Level 2

Use this Application form for connecting to the Kentucky Power distribution system and: 1.) the generating facility is not inverter based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or 2.) does not meet any of the additional conditions under a Level 1 Application (inverter based and less than or equal to 45kW generation).

Submit this Application (along with the application fee of $100) to:

D.G. Coordinator
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoordinator@aep.com

(Contact person listed is subject to change. Please visit our website for up-to date information http://www.kentucky power.com)

Applicant

Name:

Mailing Address:

City: State: Zip:

Phone: ( ) Phone: ( )

E-mail address:

Service Location

Name:

Street Address:

City: State: Zip:

Electric Service Account Number

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Alternate Contacts

Name	Company	Telephone/Email

Continued on Sheet 19-15

Tariff N.M.S. II Continued
(Net Metering Service II)

APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 2 - CONTINUED

Equipment Qualifications

Total Generating Capacity (kW) of the Generating Facility:

Type of Generator: ( ) Inverter-Based ( ) Synchronous ( ) Induction

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: _____

Continued on Sheet 19-16

Tariff N.M.S. II Continued
(Net Metering Service II)

Interconnection Agreement – Level 2

This Interconnection Agreement (Agreement) is made and entered into this _____ day of ___, 20__, by and between Kentucky Power Company (Company), and _____ (Customer). Company and Customer are hereinafter sometimes referred to individually as "Party" or collectively as "Parties"

Witnesseth:

Whereas, Customer is installing, or has installed, generating equipment, controls, and protective relays and equipment (Generating Facility) used to interconnect and operate in parallel with Company's electric system, which Generating Facility is more fully described in Exhibit A, attached hereto and incorporated herein by this Agreement, and as follows:

Location:_____

Generator Size and Type:_____

Now, therefore, in consideration thereof, Customer and Company agree as follows:

Company agrees to allow Customer to interconnect and operate the generating Facility in parallel with the Company's electric system and Customer agrees to abide by Company's Net Metering Tariff and all Terms and Conditions listed in this Agreement including any additional conditions listed in Exhibit A.

Continued on Sheet 19-17

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 2:

To interconnect to the Kentucky Power Company (Company) distribution system, the customer's generating facility shall comply with the following terms and conditions:

1. Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter/meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2. Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3. The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4. Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5. Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

Continued on Sheet 19-18

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 2, continued

6. Customer shall be responsible for protecting, at Customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

7. After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8. For Level 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

   The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS
   be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

Continued on Sheet 19-19

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 2, continued

10. Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components not resulting in increases in generating facility capacity are allowed without approval.

11. To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

    The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12. The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy). Customer shall provide Company with proof of such insurance at the time that application is made for net metering.

13. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15. The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Continued on Sheet 19-20

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 2, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

IN WITNESS WHEREOF, the Parties have executed this Agreement, effective as of the date first above written.

Customer Signature: _____ **Date:** _____

Printed Name: _____ **Title:** _____

Company Signature: _____ **Date:** _____

Printed Name: _____ **Title:** _____

Continued on Sheet 19-21

Tariff N.M.S. II Continued
(Net Metering Service II)

Interconnection Agreement – Level 2
Exhibit A

- Exhibit A will contain additional detailed information about the Generating Facility such as a single line diagram, relay settings, and a description of operation.
- When construction of the Company's facilities is required, Exhibit A will also contain a description and associated cost.
- Exhibit A will also specify requirements for a Company inspection and witness test and when limited operation for testing or full operation may begin.

RESERVED FOR FUTURE USE

~~Tariff COGEN/SPP I~~

~~(Cogeneration and/or Small Power Production - 100 KW or Less)~~

~~Availability of Service~~

~~This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a net power production capacity of 100 KW or less. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.~~

~~The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:~~

~~Option 1 -~~ ~~The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.~~

~~Option 2 -~~ ~~The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.~~

~~Option 3 -~~ ~~The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.~~

~~Monthly Charges for Delivery from the Company to the Customer~~

~~Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers with cogeneration and/or small power production facilities having a total design capacity of more than 10 KW shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.~~

~~Additional Charges~~

~~There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:~~

~~Monthly Metering Charge~~

~~The additional monthly charge for special metering facilities shall be as follows:~~

~~Option 1 -~~ ~~Not Applicable~~

~~Option 2 & 3 -~~ ~~Where meters are used to measure the excess or total energy and average on-peak capacity purchased by the Company:~~

	~~Single Phase~~	~~Polyphase~~
~~Standard Measurement~~	~~$9.25~~	~~$12.10~~
~~T.O.D. Measurement~~	~~$9.85~~	~~$12.40~~

~~*Continued on Sheet 20-2*~~

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
DATE EFFECTIVE: Services Rendered On And After March 1, 2026~~January 16, 2024~~
ISSUED BY: /s/ Tanner S. Wolffram~~Brian K. West~~
TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Tariff COGEN/SPP I Continued
(Cogeneration and/or Small Power Production - 100 KW or Less)

Additional Charges Continued

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each use.

Local Facilities Charge
Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit.

Monthly Credits or Payments for Energy and Capacity Deliveries

Energy Credit
The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter – All KWH	Variable LMP at time of delivery ¢ KWH
T.O.D. Meter	
On-Peak KWH	Variable LMP at time of delivery ¢ KWH
Off-Peak KWH	Variable LMP at time of delivery ¢ KWH

Capacity Credit
If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used,

A. 2023/2024 $3.48 kW/month
2024/2025 $3.72 kW/month
2025/2026 $3.25 kW/month, times the lowest of:

1. monthly contract capacity, or
2. current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730, or
3. lowest average capacity metered during the previous two months if less than monthly contract capacity.

Continued on Sheet 20-3

Tariff COGEN/SPP I Continued
(Cogeneration and/or Small Power Production - 100 KW or Less)

Monthly Credits or Payments for Energy and Capacity Deliveries Continued

If T.O.D. energy meters are used,

B.	2023/2024	$8.36	kW/month
	2024/2025	$8.92	kW/month
	2025/2026	$7.79	kW/month, times the lowest of:

1. on-peak contract capacity, or
2. current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by 305 or
3. lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

On-Peak and Off-Peak Periods

The on-peak period shall be defined as starting at 7:00A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00A.M. local time, Monday through Friday, and all hours of Saturday and Sunday.

Charges for Cancellation or Non-Performance Contract

If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/SPP I or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract.

Term of Contract

Contracts under this tariff shall be made for a term not less than five (5) years. A Qualifying Facility can request that avoided cost rates be set on an "as available" basis or when a legally enforceable obligation is established.

Tariff COGEN/SPP ~~H~~
(Cogeneration and/or Small Power Production--Over ~~100~~45 KW)

Availability of Service

This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a net power production capacity of over ~~100~~45 KW. In addition, cogeneration facilities must have a net power production capacity at or below 20,000 KW, and small power production facilities must have a net power production capacity at or below 5,000 KW. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:

Option 1 - The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 2 - The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 3 - The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

Monthly Charges for Delivery from the Company to the Customer

Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers with cogeneration and/or small power production facilities having a total design capacity of more than 10 KW shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.

Additional Charges

There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge

The additional monthly charge for special metering facilities shall be as follows:

Option 1 - Not Applicable

Option 2 & 3 - Where meters are used to measure the excess or total energy and average on peak capacity purchased by the Company:

	Single Phase	Polyphase
Standard Measurement	$9.25	$12.10
T.O.D. Measurement	$9.85	$12.40

Continued on Sheet 21-2

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
DATE EFFECTIVE: Services Rendered On And After March 1, 2026~~January 16, 2024~~
ISSUED BY: /s/ Tanner S. Wolffram~~Brian K. West~~
TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Tariff COGEN/SPP II Continued
(Cogeneration and/or Small Power Production-- Over 10045 KW)

Additional Charges Continued

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each case.

Local Facilities Charge
Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit.

Monthly Credits or Payments for Energy and Capacity Deliveries

Energy Credit
The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter – All KWH	Variable LMP at time of delivery ¢ KWH
T.O.D. Meter	
On-Peak KWH	Variable LMP at time of delivery ¢ KWH
Off-Peak KWH	Variable LMP at time of delivery ¢ KWH

Capacity Credit
If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used, $4.53 kW/month, times the lowest of:

~~A. 2023/2024 $3.48 kW/month~~
~~2024/2025 $3.72 kW/month~~
~~2025/2026 $3.25 kW/month, times the lowest of:~~

1. monthly contract capacity, or
2. current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730,or
3. lowest average capacity metered during the previous two months if less than monthly contract capacity.

Continued on Sheet 21-3

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
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ISSUED BY: /s/ Tanner S. Wolffram~~Brian K. West~~
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Tariff COGEN/SPP II Continued
(Cogeneration and/or Small Power Production-- Over 10045 KW)

Monthly Credits or Payments for Energy and Capacity Deliveries Continued

If T.O.D. energy meters are used, $10.88 kW/month, times the lowest of:

B.	2023/2024	$8.36	kW/month
	2024/2025	$8.92	kW/month
	2025/2026	$7.79	kW/month, times the lowest of:

1. on-peak contract capacity, or
2. current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by 305, or
3. lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

On-Peak and Off-Peak Periods
The on-peak period shall be defined as starting at 7:00 A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00 A.M., local time, Monday through Friday, and all hours of Saturday and Sunday.

Charges for Cancellation or Non Performance Contract
If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/ SPP II or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract.

Term of Contract
Contracts under this tariff shall be made for a term not less than five (5) years and no longer than twenty (20) years. A Qualifying Facility ("QF") can request that avoided cost rates be set on an "as available" basis or when a legally enforceable obligation is established.

Continued on Sheet 21-4

DATE OF ISSUE: August 29, 2025February 8, 2024
DATE EFFECTIVE: Services Rendered On And After March 1, 2026January 16, 2024
ISSUED BY: /s/ Tanner S. WolframBrian K. West
TITLE: Director, Regulatory ServicesVice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Tariff COGEN/SPP Continued
(Cogeneration and/or Small Power Production-- Over 45 KW)

Term of Contract Continued

The Company shall not provide a prospective Cogen/SPP customer with a contract for service under this tariff until the customer has met the burden of establishing a legally enforceable obligation ("LEO") under PURPA. A LEO will be established for the Customer's facility when the following criteria have been met to the Company's satisfaction:

1. Documentation of having obtained Qualifying Facility status from FERC pursuant to the certification procedures set out in 18 CFR 292.207. QFs that "self-certify" must provide the Company with its submitted FERC Form No. 556 – Certification of QF Status for Small Power Production and Cogeneration Facilities.

2. Documentation provided to the electric utility of all of the following: (i) a description of the location of the project and its proximity to other projects within one mile of the project and within 10 miles of the project, which are owned or controlled by the same developer, and (ii) an estimated, non-binding, good faith estimate of the energy production for the project that includes the kilowatt-hours or megawatt hours to be produced by the QF for each month and year of the entire term of the project's anticipated avoided cost power purchase agreement.

3. Documentation of an interconnection application with the appropriate electric utility, and proof of payment of applicable application fees.

4. Documentation of meaningful steps to obtain site control adequate to commence construction of the project at the proposed location.

5. Documentation of all applications, including filing fees, to obtain all necessary local permitting and zoning approvals.

6. If qualifying as a "cogeneration facility" as defined by 18 CFR 292.202(c), written proof, provided to the electric utility, of a steam host that is willing to contract for steam over the full term of the project's anticipated power purchase agreement for a cogeneration facility.

7. Proof of a deposit, paid in full, to cover the estimated costs for a system impact or facilities study, such as an engineering review or distribution study, should a study or studies become necessary.

Tariff C.S.-I.R.P.
(Contract Service – Interruptible Power)

Availability of Service

Available for service to customers who contract for service under the Company's Industrial General Service (I.G.S.) tariff. The Company reserves the right to limit the total contract capacity for all customers served under this Tariff to 75,000 kW.

Loads of new customers locating within the Company's service area or load expansions by existing customers may be offered interruptible service as part of an economic development incentive. Such interruptible service shall not be counted toward the limitation on total interruptible power contract capacity, as specified above, and will not result in a change to the limitation on total interruptible power contract capacity.

Conditions of Service

The Company will offer eligible customers the option to receive interruptible power service. This interruptible service will be consistent with PJM's Load Management Resource Product – Capacity Performance Demand Response requirement, hereafter referred to as the "PJM Demand Response Program", subject to any limitations on the availability of that Program by PJM. To be eligible for the credit, customers must be able to provide interruptible load (not including behind the meter diesel generation) of at least one (1) MW at a single site and commit to a minimum four (4) year contract term. The contract shall provide that 90 days prior to each contract anniversary date, the customer shall re-nominate the amount of interruptible load for the upcoming contract year, except that the cumulative reductions over the life of the contract shall not exceed 20% of the original interruptible load nominated under the contract. If no re-nomination is received at least 90 days prior to the contract anniversary date, the prior year's interruptible load shall apply for the forthcoming contract year.

Upon receipt of a request from the Customer for interruptible service, the Company will provide the Customer with a written addendum containing the rates and related terms and conditions of service under which such service will be provided by the Company. If the parties reach an agreement based upon the offer provided to the Customer by the Company, such written contract will be filed with the Commission. The contract shall provide full disclosure of all rates, terms and conditions of service under this Tariff, and any and all agreements related thereto, subject to the designation of the terms and conditions of the contract as confidential, as set forth herein.

The Customer shall provide reasonable evidence to the Company that the Customer's electric service can be interrupted in accordance with the provisions of the written agreement including, but not limited to, the specific steps to be taken and equipment to be curtailed upon a request for interruption.

The Customer shall contract for capacity sufficient to meet average maximum interruptible power requirements, but in no event will the interruptible amount contracted for be less than 1,000 KW at any delivery point.

The Company reserves the right to test and verify the customer's ability to curtail. Any such test or verification may require actual physical interruption or curtailment, to the extent such testing or interruption is required under PJM's Demand Response Program.

NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS SCHEDULE.

Except as otherwise provided in the written agreement, the Company's Terms and Conditions of Service shall apply to service under this tariff.

Continued on Sheet 22-2

Tariff C.S.-I.R.P. Continued
(Contract Service – Interruptible Power)

Rate
Credits under this tariff of $3.68/kW/month will be provided for interruptible load that qualifies under PJM's Demand Response Program rules as capacity for the purpose of the Company's Fixed Resource Requirement (FRR) obligation.

Tariff	Tariff Type	Tariff Code Description	Tariff Description
321	IR	CS-IRP SEC	IRP-IGS SECONDARY
330	IR	CS-IRP PR	IRP-IGS PRIMARY
331	IR	CS-IRP ST	IRP-IGS SUBTRANSMISSION
332	IR	CS-IRP TR	IRP-IGS TRANSMISSION

Charges for service under this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect the firm service rates otherwise available to the Customer.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	Sheet No. 32
Environmental Surcharge	Sheet No. 3223
Decommissioning Rider	Sheet No. 3334
Securitized Surcharge Rider	Sheet No. 3445
Federal Tax Cut Tariff	Sheet No. 3556
City's Franchise Fee	Sheet No. 3667
School Tax	Sheet No. 3778

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-52 4.

Confidentiality
All terms and conditions of any written contract under this Tariff shall be protected from disclosure as confidential, proprietary trade secrets, if either the Customer or the Company requests a Commission determination of confidentiality pursuant to 807 KAR 5:001 Section 7 and the request is granted.

Special Terms and Conditions
Except as otherwise provided in the written agreement, this Tariff is subject to the Company's Terms and Conditions of Service.

Continued on Sheet 22-3

Tariff C.S.-I.R.P. Continued
(Contract Service – Interruptible Power)

Special Terms and Conditions Continued

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP ~~II~~ or by special agreement with the Company.

Rider D.R.S.
(Demand Response Service)

Availability of Service

Available for Demand Response Service ("DRS") to customers that take firm service from the Company under a standard demand-metered rate schedule and that have the ability to curtail load under the provisions of this Schedule. Each customer electing service under this Schedule shall contract, via a Contract Addendum, for a definite amount of firm and interruptible capacity agreed to by the Company and the customer. The interruptible capacity amount shall not exceed the Customer's average on-peak demand for the past 12 months. The Company reserves the right to limit the aggregate amount of interruptible capacity contracted for under this Schedule. The Company will take Customer DRS requests in the order received. Customers taking service under this Schedule shall not participate in any PJM demand response program for Capacity.

Conditions of Service

1. The Company, in its sole discretion, reserves the right to call for curtailments of the Customer's interruptible load at any time. Such interruptions shall be designated as "Discretionary Interruptions" and shall not exceed sixty (60) hours of interruption during any Interruption Year. The "Interruption Year" shall be defined as the consecutive twelve (12) month period commencing on June 1 and ending on May 31. Should this Schedule become effective on a date other than June 1, the period from the effective date of this Schedule until the next May 31 after such effective date shall be referred to as the "Initial Partial Interruption Year." In any Initial Partial Interruption Year, Discretionary Interruptions shall not exceed a number of hours equal to the product of the number of full calendar months during the Initial Partial Interruption Year and the annual interruption hours divided by 12.

2. The monthly Interruptible Demand Credit Rate shall be $5.50/kW-month, credited to participating Customers' bills for standard tariff service.

3. The Company will endeavor to provide the Customer with as much advance notice as possible of a Discretionary Interruption. The Company shall provide notice at least 90 minutes prior to the commencement of a Discretionary Interruption. Such notice shall include both the start and end time of the Discretionary Interruption. For any Discretionary Interruption, the Customer shall be permitted to choose not to interrupt and to continue to operate during the event, provided that the Customer pays the DRS Event Failure Charge. Discretionary Interruptions shall begin and end on the clock hour.

4. Discretionary Interruption events shall be three (3) consecutive hours and there shall not be more than six (6) hours of Discretionary Interruption per day.

5. The Company will inform the Customer regarding the communication process for notices to curtail. The Customer is ultimately responsible for receiving and acting upon a curtailment notification from the Company.

6. The minimum interruptible capacity contracted for under this Schedule will be 500 kW. Customers with multiple electric service accounts at a single location may aggregate those individual accounts to meet the 500 kW minimum interruptible capacity requirement under this Schedule; however, the interruptible capacity committed for each individual account shall not be less than 100 kW.

7. All Customer meter data required under this Schedule shall be determined from 15- or 30-minute integrated metering, as applicable based on the Customer's rate schedule, with remote interrogation capability and demand recording equipment. Such metering equipment shall be owned, installed, operated, and maintained by the Company.

Continued on Sheet 23-2

Rider D.R.S. Continued
(Demand Response Service)

8. NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS SCHEDULE.

Interruptible Capacity Reservation
The Customer shall have established a total Capacity Reservation under its Contract for Service under the applicable demand-metered rate schedule. In a Contract Addendum, the Customer shall designate a set amount of kW of that total Capacity Reservation as the Firm Service Capacity Reservation, which is not subject to interruption under this Schedule. The Interruptible Capacity Reservation shall be the Customer's average on-peak demand over the past 12 months in excess of the Firm Service Capacity Reservation.

The Interruptible Capacity Reservation is subject to annual review and adjustment by the Company and the Customer.

Monthly Interruptible Demand Credit
The monthly Interruptible Demand Credit shall be equal to the product of Demand Credit per kW-month and the Customer's Interruptible Capacity Reservation kW.

Interruption Event Compliance
A Customer will be determined to have failed a DRS interruption event if the Customer has not achieved at least ninety (90) percent of their agreed upon interruptible capacity reservation during the duration of a DRS event.

DRS Event Failure
A Customer that fails one or more DRS interruption events shall repay a portion of the Customer's total annual DRS Interruptible Demand Credit per the following table:

Number of Failures	Penalty Payment %
Failure 1	5%
Failure 2	10%
Failure 3	10%
Failure 4	15%
Failure 5	15%
Failure 6	20%
Failure 7	25%
Totals	100%

The DRS Event Failure Charge equals the Customer's Interruptible Capacity Reservation kW, times the DRS Interruptible Demand Credit Rate, times 12, times the corresponding DRS Event Failure Charge Penalty Payment % set forth in the table above. Under no circumstance will a Customer be charged for DRS interruption event failures in an amount greater than the annual amount of DRS Interruptible Demand Credits the Customer would have or has received in an Interruption Year.

Settlement
The net amount of the monthly Interruptible Demand Credit and any DRS Event Failure Charge will be included in the Customer's monthly bill for electric service under its demand-metered rate schedule.

Continued on Sheet 23-3

Rider D.R.S. Continued
(Demand Response Service)

Term

A Contract Addendum term under this Schedule shall be at least one (1) Interruption Year and shall continue for each subsequent Interruption Year until either party provides written notice no later than April 2 of its intention to discontinue service effective June 1 under the terms of this Schedule. Any participating Customer must participate for at least one full Interruption Year, therefore a Customer that begins service under this rider during the Initial Partial Interruption Year must then also participate in the subsequent full Interruption Year.

~~Tariff V.C.S.~~
~~(Voluntary Curtailment Service)~~

~~This Rider provides the Customer with the opportunity to reduce their cost of electric service by curtailing usage during Voluntary Curtailment Events requested by the Company. Upon each event, the Customer shall have the option, but not the obligation, to curtail usage at their premises and be compensated by the Company as provided below.~~

~~Availability of Service~~

~~The initial term of this tariff is two (2) years beginning January 28, 2022. Eligible customers must have a curtailable usage of not less than 1,000 kW at the metering point for a single account for electric service, have accounts that are current, and maintain satisfactory credit criteria as defined under the Company's Terms and Conditions under Deposits, Section D. All provisions of the applicable standard tariff for electric service will apply except as modified herein. Customers participating in a third-party demand response program and customers receiving service under special contracts, including COGEN/SPP contracts, are not eligible to participate under this Rider. Customers in this program are also subject to curtailments due to system emergencies in the same manner as all other firm service customers.~~

~~Monthly Charges and Credits~~

~~Customer's net monthly bill for service provided under this Rider will be calculated in accordance with the Company's applicable rate schedule, with the exception that the Voluntary Curtailment Credit will be applied as a line item on the Customer's bill.~~

~~The Voluntary Curtailment Event Hours and the Voluntary Curtailment Price will be quoted to the Customer by no later than 5:00 p.m. ET of the day prior to the Event Day.~~

~~The Voluntary Curtailment Price will be based upon the Day-Ahead Market price of energy at the time of the Voluntary Curtailment Event, as determined in the Company's sole judgment, but not less than $100 per MWh. The AEPKY_RESID_AGG LMP shall be used to develop the Voluntary Curtailment Price.~~

~~Conditions of Service~~

1. ~~The Company reserves the right to request a Voluntary Curtailment Event at any time at the Company's sole discretion. The Company will call no more than two (2) Voluntary Curtailment Events per day. The Events must be separated by at least one (1) non-event hour.~~
2. ~~Customers must request enrollment in the program thirty (30) days before participating in a Voluntary Curtailment Event. A fully executed contract is required before a customer may participate in a Voluntary Curtailment Event.~~
3. ~~The Company shall notify the Customer of a Voluntary Curtailment Event by e-mail, text or automated phone message. The Customer shall designate their representative(s) to receive said notifications.~~
4. ~~No responsibility or liability of any kind shall attach to or be incurred by the Company or the AEP System for, or on account of, any loss, cost, expense or damage caused by or resulting from, either directly or indirectly, any curtailment of service under the provisions of this Rider.~~
5. ~~The Customer shall not receive credit for any curtailment periods in which the Customer's usage is already reduced due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, economic conditions or any event other than the Customer's normal operating conditions.~~
6. ~~The Customer's participation in any Company capacity-based demand response program takes priority over this program. No credit shall be given under this program for hours that a customer is responsible for curtailing under another program. An interval meter is required for service under this Rider. The incremental cost of any special metering, communications or control equipment required for service under this Rider beyond that normally provided shall be borne by the Customer.~~

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
DATE EFFECTIVE: Services Rendered On And After March 1, 2026~~January 16, 2024~~
ISSUED BY: /s/ Tanner S. Wolffram~~Brian K. West~~
TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Tariff F.P.
(FlexPay Program)

Availability of Service

This tariff is available on a voluntary basis to all residential customers who have an Advanced Metering Infrastructure (AMI) meter installed at their residence, except as provided below.

This tariff is not available to residential customers taking metered service under Tariff R.S.D. or customers with medical, life threatening, or life support conditions; customers having on-site generation operated in parallel with the Company's system; or customers on the Average Monthly Payment (AMP) plan or Equal Payment Plan (Budget). It also is not available to customers without a valid and operable electronic communication method (i.e., text or electric mail). It also is not available to a customer scheduled for a disconnection of service for nonpayment who has initiated the process for enrollment in this tariff two or more times within a thirty (30) day period without completing all of the requirements for enrollment.

Program Description

Kentucky Power's FlexPay Program is a voluntary payment option that allows customers to prepay for, and pay as they use, electric service.

Terms and Conditions

1. Service under FlexPay will be offered to a customer under the customer's otherwise applicable standard residential rate schedule. Billing will be based on the customer's daily usage, the effective base rate, the tax rate, and all applicable riders and fees. Fixed charges will be applied to the account on a daily basis based on 1/30 of the total fixed charges. These amounts will be subtracted from the customer's daily FlexPay account balance.
2. To enroll in FlexPay, a customer must make an initial payment of $40.00. Any deposit that an existing customer has previously paid to the Company will be applied to the customer's current account balance, with the remaining credit/debit balance transferred to the customer's prepay balance. A customer with an outstanding current balance or final account balance from a previous account may carry-over up to $500 of the account balance to the FlexPay Program. Any payments made to the account will first have a 20% portion of the payment applied to the arrears balance before it is credited to the customer's account until the past due balance is paid.
3. The customer is responsible for monitoring prepaid usage and ensuring that the account balance is sufficient to continue electric service. The customer will be notified when the account reaches the customer-selected balance threshold or the minimum threshold amount of $25.00. Notification will occur through the customer's preferred form of communication, including email, and/or text message. A customer web portal will be available to view the customer's usage information.
4. Should a customer's balance reach zero, the customer will be notified via the customer's chosen communication method. The customer will have until the beginning of the next business day to reestablish a positive balance or the customer's meter will automatically be disconnected during normal business hours. Normal business hours are 8:00 a.m. to 5:00 p.m., Monday through Thursday, and 8:00 a.m. to noon on Fridays, excluding Company-observed holidays and moratoriums. Customers will be required to adjust their payment to cover any accrued balance for usage during weekends, holidays and moratoriums. Once the customer's payment is received and accepted, service will be restored by the Company in a timely manner.

Continued on Sheet 24-2

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TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
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Tariff V.C.S. Continued
(Voluntary Curtailment Service)

Curtailed Demand

For each Voluntary Curtailment Event, Curtailed Demand shall be defined as the difference between the Customer's Average On-Peak Demand and the maximum sixty (60) minute integrated demand in kW during the Voluntary Curtailment Event. The Curtailed Demand so computed will not be less than zero (0).

The Company shall determine the Customer's Average On-Peak Demand in kW specified in a contract or contract addendum for service under this Rider. The Customer's Average On-Peak Demand will be reviewed annually. Annual, seasonal or monthly Average On-Peak Demands may be established based upon Customer's historic usage patterns. For the purpose of determining the Average On-Peak Demand, the on-peak period is defined as 7:00 a.m.to 11:00 p.m. ET for all weekdays, Monday through Friday.

Voluntary Curtailment Credit

For each Voluntary Curtailment Event, the Event Credit shall be the product of the Curtailed Demand, the number of Voluntary Curtailment Event Hours and the Voluntary Curtailment Price.

The Voluntary Curtailment Credit will be the sum of the Event Credits for the calendar month.

The Voluntary Curtailment Credit will be applied to the Customer's bill within forty-five (45) days after the end of the month in which the Voluntary Curtailment Event occurred.

The Voluntary Curtailment Credit applied to the Customer's bill for service will be recorded in the Federal Energy Regulatory Commission's Uniform System of Accounts under Account 555, Purchased Power, and will be recorded in a subaccount so that the separate identity of this amount is preserved.

Non-Compliance Provision

There are no charges for non-compliance with a Voluntary Curtailment Event.

Term

Contracts under this Rider shall be made for an initial period of one (1) year and shall remain in effect thereafter until either party provides to the other at least thirty (30) days written notice of its intention to discontinue service under this Rider.

Tariff F.P.
(FlexPay Program)

Terms and Conditions Continued

5. Financial assistance received for a FlexPay account will be credited to the balance of the FlexPay account upon receipt of the funds.
6. Customers presenting a Winter Hardship Reconnect, Certificate of Need, or Medical Certificate as provided in 807 KAR 5:006, Sections 14, 15, and 16 will be removed from FlexPay and placed on the tariff that is otherwise applicable to the customer's service.
7. No deposit, reconnect, or late fee charges shall apply to customers enrolled in FlexPay.
8. When the Company receives a dishonored negotiable instrument (i.e. returned check), any account credits associated with that instrument will be removed from the customer's account. If the removal of the credits results in the customer's balance reaching zero, the customer will be notified and will have until the beginning of the next business day to reestablish a positive balance or the customer's meter will automatically be disconnected during normal business hours.
9. Actual billing will continue to be based upon the applicable rate and meter readings obtained to determine consumption. FlexPay customers are re4quired to participate in and receive their information through the Company's paperless billing program. Customers will continue to receive an online monthly statement summary containing all of the charges, usage, and payments applied during their normal 30-day billing cycle.
10. Customer accounts must be funded through a Company authorized payment channel, including immediate. payment via telephone or website using electronic check, debit or credit cards, and any in-person pay station. Each authorized payment method is subject to Company guidelines. Timing of the payments to the accounts cannot be guaranteed if payment is made through an unauthorized pay agent or by mail.
11. The customer may cancel service under this tariff at any time and will be returned to the applicable traditional post-pay billing option in accordance with Kentucky Power's Commission approved tariffs.
12. Settlement occurs when participation in the plan is terminated. This happens if an account is final billed or if the customer requests termination. If the account finals off-cycle during the billing period, the remaining monthly fixed charges and fees that have not been collected will be applied to the final bill. After settlement of the FlexPay account, any remaining unused balance will be transferred to the customer's other active account(s). If the customer does not have any other active accounts the Company shall refund by one of the following means: a prepaid card, a check, or electric funds transfer (EFT).

Tariff E.D.R.
(Economic Development Rider)

Availability of Service

To encourage economic development in the Company's service territory, limited-term reductions in billing demand charges described herein are offered to qualifying new and existing retail customers who make application for service under this Rider.

Service under this Economic Development Rider (EDR) is intended for specific types of commercial and industrial customers whose operations, by their nature, will promote sustained economic development based on plant and facilities investment and job creation. Availability is limited to customers on a first-come, first-served basis until such time as a total of 250 MW of new load has been added to Kentucky Power's system under the EDR. The EDR is available to commercial and industrial customers served under Tariffs L.G.S. and I.G.S. who meet the following requirements:

(1) A new customer must have at least a monthly maximum billing demand of 500 kW. An existing customer must increase its monthly maximum billing demand by at least 500 kW over the current Base Maximum Billing Demand in order to receive the Incremental Billing Demand Discount (IBDD).

(2) A new customer, or the business expansion by an existing customer, will receive a Supplemental Billing Demand Discount (SBDD) for creating and sustaining at least 25 new permanent full time jobs over the contract term at the service location. The Company reserves the right to verify job counts. Failure to demonstrate the creation of new employment positions or to maintain the employment during the contract term will result in the termination of the supplemental discount.

(3) The customer must demonstrate to the Company's satisfaction that, absent the availability of this EDR, the qualifying new or increased electrical demand would be located outside of the Company's service territory or would not be placed in service.

Terms and Conditions

(1) The Company will offer the EDR to qualifying customers with new or increased load when the Company has sufficient generating capacity available. When sufficient generating capacity is not available, the Company will procure the additional capacity on the customer's behalf. The cost of capacity procured on behalf of the customer shall reduce on a dollar-for-dollar basis the customer's IBDD and SBDD. Such reduction shall be capped so that the customer's maximum demand charge shall be the non- discounted tariff demand charge. The reduction will be applied in reverse chronological order beginning with the most recent customer to receive discounted service under this tariff. The last customer to sign up for the EDR tariff would be the first customer responsible for paying the cost of incremental capacity purchases. In any year during the discount period in which the customer pays the full tariff demand charge for all twelve months, the Company will reduce the term of the contract by one year.

(2) The new or increased load cannot accelerate the Company's plans for additional generating capacity during the period for which the customer receives a demand discount. Customers receiving Temporary Service are not eligible for this EDR.

(3) To receive service under this EDR, the customer shall make written application to the Company with sufficient information contained therein to determine the customer's eligibility for service. At a minimum, such information must include:

Continued on Sheet 25-2

Tariff E.D.R. Continued
(Economic Development Rider)

Terms and Conditions Continued

a. A description and good faith estimate of the new or increased load to be served during each year of the contract,
b. The number of new employees or jobs that will be added as a result of the new load,
c. A description of the anticipated capital investment,
d. A description of all other federal, state or local economic development tax incentives, grants, or any other incentives or assistance associated with the new or expanded project, and
e. A statement that without the EDR discount, the customer would locate elsewhere or would choose not to expand within Kentucky Power's service territory.

(4) For new and existing customers, billing demands for which reductions will be applicable under this EDR shall be for service at a new service location or expanded production at an existing facility and not merely the result of a change of ownership. Relocation of the delivery point of the Company's service, moving existing equipment from another Company-served location or load transfers from another Company-served location do not qualify as a new service location. Relocating existing facilities from within the Company's service territory shall not disqualify the customer from the IBDD as long as the new relocated facility exceeds the Base Maximum Billing Demand of the previous facility by the minimum required amount.

(5) For existing customers, billing demands for which deductions will be applicable under this EDR shall be the result of an increase in business activity and not merely the result of resumption of normal operations following a force majeure, strike, equipment failure, renovation or refurbishment, or other such abnormal operating condition. In the event that such an occurrence has taken place prior to the date of the application by the customer for service under this EDR, the monthly Base Maximum Billing Demand shall be adjusted as appropriate for this analysis to eliminate the effects of such occurrence.

(6) Service under the EDR will be offered under the applicable Tariff L.G.S. or I.G.S. schedule. An EDR will be filed as a Special Contract and must be approved by the Kentucky Public Service Commission before it can be implemented. The total contract period is equal to twice the number of years for which the customer receives a demand discount. The special contract term will be for two (2), four (4) six (6), eight (8), or ten (10) years only.

(7) The IBDD and the SBDD, if applicable, begin when the customer's new or expanded operations are billed for service under this Rider. Temporary jobs created during the construction of new facilities or the expansion phase of existing operations are not eligible to be counted as permanent jobs for the purposes of this EDR.

(8) If construction of new or expanded local distribution and/or transmission related facilities by the Company is required in order to provide the additional service, the customer may be required to make a contribution-in-aid of construction (CIAC) for the installed cost of such facilities pursuant to the provisions of the Company's Terms and Conditions of Service. The total cost of the CIAC, including gross-up by the effect of applicable taxes, will be recovered over the life of the EDR contract period, with no less than 80% recovered during the period for which the customer receives a demand discount. If the customer breaches the terms of the contract or ends the contract prematurely, any unpaid contribution-in-aid of construction must be paid to the Company, and any EDR discounts provided to the customer must be repaid to the Company. CIAC payment provided under this Rider supersedes other payment provisions only in the Company's Terms and Conditions Sheet 2-5 Section 9.

Continued on Sheet 25-3

Tariff E.D.R. Continued
(Economic Development Rider)

(9) The L.G.S., and I.G.S. tariffs each contain a monthly minimum billing demand charge provision. The minimum demand charge provision is waived for EDR customers for up to 36 months depending upon the length of the contract. The provision is waived for the first 36 months of a 10 year contract, the first 24 months of an 8 year contract and the first 12 months of a 6 year contract. If during the special contract discount period, the customer's monthly demand falls below the minimum billing demand level for four (4) consecutive months or six (6) months total in a contract year, then the EDR discount will not be applied and the appropriate tariff minimum billing demand charge provision will be in force until the customer achieves the minimum billing demand level. Applicable EDR discounts will be applied to the qualifying incremental maximum billing demand only and will appear as a separate line item on the customer's bill.

Determination of Monthly Qualifying Incremental Billing Demand
For the purposes of this Rider, the monthly qualifying incremental billing demand will be calculated in the following manner:

Where the new qualifying incremental demand resides in new facilities (or separate facilities for existing customers), those facilities may be metered on a separate meter according to Tariffs L.G.S., I.G.S., for the current billing period and the incremental billing demand will be calculated based upon that facility's meter readings.

Where the new qualifying incremental demand resides in a customer's existing facility with sufficient service and metering capability to accommodate the business expansion, the qualifying incremental billing demand is equal to demand in excess of the Base Maximum Billing Demand. The Base Maximum Billing Demand for each billing month will be calculated by the Company as the average of the previous three years, corresponding month maximum billing demands, subject to Terms and Conditions Items (3) and (4), and will be agreed to by the customer in advance.

Determination of Incremental Billing Demand Discount
Customers meeting all Availability of Service and Terms and Conditions above may contract for service for a period of up to ten (10) years, with a commensurate discount period of up to five (5) years. The qualifying incremental billing demand charge shall be reduced by 50%, 40%, 30%, 20%, 10% in the order of the Customer's choosing at the time of the contract filing. A sample illustration of an (IBDD) for a ten (10) year contract follows:

(a) For the twelve consecutive monthly billings of the first contract year, the qualifying incremental billing demand charge shall be reduced by 50% from the applicable tariff L.G.S. or I.G.S., demand charge;

(b) For the twelve consecutive monthly billings of the second contract year, the qualifying incremental billing demand charge shall be reduced by 40% from the applicable tariff L.G.S. or I.G.S., demand charge;

(c) For the twelve consecutive monthly billings of the third contract year, the qualifying incremental billing demand charge shall be reduced by 30% from the applicable tariff L.G.S. or I.G.S., demand charge;

(d) For the twelve consecutive monthly billings of the fourth contract year, the qualifying incremental billing demand charge shall be reduced by 20% from the applicable tariff L.G.S. or I.G.S., demand charge, but shall not be less than the applicable tariff rate schedule minimum billing demand;

(e) For the twelve consecutive monthly billings of the fifth contract year, the qualifying incremental billing demand charge shall be reduced by 10% from the applicable tariff L.G.S. or I.G.S., demand charge, but shall not be less than the applicable tariff rate schedule minimum billing demand; and

Continued on Sheet 25-4

Tariff E.D.R. Continued
(Economic Development Rider)

(f) All subsequent monthly billings shall be at the full charges stated in the applicable tariff rate schedule for contract years six (6) through ten (10).

The starting point for the IBDD is dependent upon the length of contract: i.e., an eight (8) year contract will have four (4) years of discount and a maximum annual IBDD of 40% in one year. Similarly, a six (6) year contract will have three (3) years of discount and a maximum annual IBDD of 30% in one year.

Determination of Supplemental Billing Demand Discount

At the Company's discretion, a (SBDD) which is applicable to the monthly incremental billing demand charge is available to customers meeting all Availability of Service and Terms and Conditions above, and that create at least twenty five (25) new permanent job opportunities in the facility and that maintain those job opportunities in each discount year. The amount of additional discount is determined by the actual number of jobs maintained in each year. The order in which the SBDD is applied will follow the same order selected by the Customer for the IBDD contract. A sample illustration of the SBDD for a ten (10) year contract follows:

(a) For the twelve consecutive monthly billings of the first contract year, the qualifying incremental billing demand charge shall be reduced an additional 5% for an increase of at least 50 jobs or 2.5% for an increase of at least 25 jobs;

(b) For the twelve consecutive monthly billings of the second contract year, the qualifying incremental billing demand charge shall be reduced an additional 4.5% for an increase of at least 50 jobs or 2.0% for an increase of at least 25 jobs;

(c) For the twelve consecutive monthly billings of the third contract year, the qualifying incremental billing demand charge shall be reduced an additional 4% for an increase of at least 50 jobs or 1. 5% for an increase of at least 25 jobs;

(d) For the twelve consecutive monthly billings of the fourth contract year, the qualifying incremental billing demand charge shall be reduced an additional 3.5% for an increase of at least 50 jobs or 1. 0% for an increase of at least 25 jobs;

(e) For the twelve consecutive monthly billings of the fifth contract year, the qualifying incremental billing demand charge shall be reduced an additional 3% for an increase of at least 50 jobs or 0.5% for an increase of at least 25 jobs; and

(f) All subsequent monthly billings shall be at the full charges stated in the applicable tariff rate schedule for contract years six (6) through ten (10)

The length of the SBDD shall be identical to the length of the IBDD. The starting point for the discount will be commensurate with the contract length, i.e., an eight (8) year contract will have four (4) years of discount with a maximum SBDD of either 4.5% or 2.0% as appropriate during one year of the contract.

The appropriate discount(s) shall be applicable over a period of up to 60 consecutive billing months as selected by the Customer in 12-month increments at the time of the contract.

Continued on Sheet 25-5

Tariff E.D.R. Continued
(Economic Development Rider)

Terms of Contract

A contract or agreement addendum for service under this Rider, in addition to service under Tariffs L.G.S. or I.G.S., shall be executed by the Customer and the Company for the time period which includes the start-up period and the multi-year period during which a Total Demand Charge discount is in effect and an equal multi-year period during which the customer agrees to pay the full rates in the applicable Tariff rate schedule.

At a minimum, the contract or agreement addendum shall specify the Base Maximum Billing Demand, the anticipated annual total qualifying demand, the Adjustment Factor and related provisions to be applicable under this Rider, and the effective date for the contract addendum.

The customer may discontinue service under this Rider before the end of the contract or agreement addendum only by reimbursing the Company for any and all demand reductions received under this Rider when billed at the applicable tariff schedule rate. In order to secure repayment of demand reductions received under this Rider, all customers whose contracts have an initial start date of January 16, 2024 and after will be required to post appropriate security (cash, surety bond, letter of credit, or other form of security acceptable to the Company) in an amount up to the total demand reductions received and estimated to be received under the contract or agreement addendum, and upon any additional terms as established in the contract or agreement addendum.

Special Terms and Conditions

Except as otherwise provided in this Rider, written agreements shall remain subject to all of the provisions of the applicable tariffs. This Rider is subject to the Company's Terms and Conditions of Service.

Tariff R.E.A.
(Residential Energy Assistance)

Proceeds of the charge and a Company contribution (that equals two times the amount collected from the per meter charge) will be used to provide financial assistance to eligible residential customers' electric bills during peak heating months (January through April).

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D.2

Rate
$0.40 per month per residential account.

Programs
Participation in the programs below will be determined by the residential customer's local community action agency in accordance with guidelines approved by the Commission and the availability of funds. Customer participation is limited to one program each calendar year.

Home Energy Assistance in Reduced Temperatures (HEART)
Participating low-income residential customers, whose primary source of heat is electric, are eligible to receive an electric bill credit of $115.00 a month for bills rendered in January through April.

Participating low-income residential customers, whose primary source of heat is non-electric, are eligible to receive an electric bill credit of $58.00 a month for bills rendered in January through April.

Temporary Heating Assistance in Winter (THAW)
Participating residential customers, who are experiencing temporary economic hardships, are eligible to receive electric bill credits totaling no more than $175.00 for bills rendered in January through April in any single calendar year.

Tariff K.E.D.S.
(Kentucky Economic Development Surcharge)

Proceeds of the surcharge and matching Company contributions will be used to fund economic development programs and activities as determined by the Company within the 20 counties comprising Kentucky Power's certified territory.

Applicable
To Tariffs G.S, S.G.S. – T.O.D., M.G.S. – T.O.D., L.G.S., L.G.S. – T.O.D., I.G.S., C.S. – I.R.P., M.W.

Rate
$1.00 per month per commercial account.

Tariff D.S.M.C.
(Demand-Side Management Adjustment Clause)

Applicable

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., and M.W.

Rate

1. The Demand-Side Management (DSM) clause shall provide for periodic adjustment per KWH of sales equal to the DSM costs per KWH by customer sector according to the following formula:

$$\text{(c) Adjustment Factor} = \frac{\text{DSM}}{\text{S(c)}}$$

Where DSM is the cost by customer sector of demand-side management programs, net lost revenues, incentives, and any over/under recovery balances; (c) is customer sector; and S is the adjusted KWH sales by customer sector.

2. Demand-Side Management (DSM) costs shall be the most recent forecasted cost plus any over/under recovery balances recorded at the end of the previous period.

   a. Program costs are any costs the Company incurred associated with demand-side management which were approved by the Kentucky Power Company DSM Collaborative. Examples of costs to be included are contract services, allowances, promotion, expenses, evaluation, lease expense, etc. by customer sector.

   b. Net lost revenues are the calculated net lost revenues by customer sector resulting from the implementation of the DSM programs.

   c. Incentives are a shared-savings incentive plan consisting of one of the following elements: The efficiency incentive, which is defined as 15 percent of the estimated net savings associated with the programs. Estimated net savings are calculated based on the California Standard Practice Manual's definition of the Total Resources Cost (TRC) test, or the maximizing incentive which is defined as 5 percent of actual program expenditures if program savings cannot be measured.

   d. Over/ Under recovery balances are the total of the differences between the following:

      i. the actual program costs incurred versus the program costs recovered through DSM adjustment clause, and

      ii. the calculated net lost revenues realized versus the net lost revenues recovered through the DSM adjustment clause, and

      iii. the calculated incentive to be recovered versus the incentive recovered through the DSM adjustment clause.

3. Sales (S) shall be the total ultimate KWH sales by customer sector less non-metered, opt-out and lost revenue impact KWHs by customer sector.

Continued on Sheet 28-2

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Rate Continued

4. The provisions of the Demand-Side Management Adjustment Clause will be effective for the period ending December 31, 2025.

5. The DSM adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

6. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

7. The resulting range for each customer sector per KWH during the three-year Experimental Demand-Side Management Plan is as follows:

	Customer Sector		
	Residential	Commercial	Industrial*
DSM(c)	$1,107,281	$817,419	0
S(c)	1,887,324,885	1,425,512,271	0
Adjustment Factor	$0.000587	$0.000573	0

* The Industrial Sector has been discontinued pursuant to the Commission's Order dated September 28, 1999.

Program Descriptions

The D.S.M.C. program availability, program, rate, and equipment descriptions follow:

Continued on Sheet 28-3

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Program: TEE – Targeted Energy Efficiency

Availability of Service
Available on a voluntary basis until funds are depleted to individual residential customers receiving retail electric service from the Company, who have primary electric heat and use an average of 700 kWh per month. Residential customers without primary electric heating may also be eligible for limited efficiency measures if they have electric water heating and use an average of 700 kWh per month from November through March. To qualify, the household's income cannot exceed the designated poverty guidelines as administered by the local community action agency.

Program Description
The Targeted Energy Efficiency (TEE) Program provides weatherization and energy efficiency services to qualifying residential customers who need help reducing their energy bills. The Company provides funding for this program through the Kentucky Community Action network of not-for-profit community action agencies.

Two different supplemental assistance funds are available under the Company's TEE Program:

- **The Weatherization Assistance Program:** Kentucky Power's Weatherization Assistance Program is designed to provide supplemental funding to the Department of Energy's Weatherization Assistance Program operated by the Kentucky Community Action network of not-for-profit community action agencies. Funds from this program provide energy saving improvements to an existing home. Program services include residential energy audits, the installation of home weatherization/energy conservation items and customer education on home energy efficiency. The home weatherization/energy conservation measures available under this program may include, but are not limited to:

    - High efficiency lighting
    - Domestic hot water pipe insulation
    - Water heater insulation wrap (electric domestic hot water only)
    - Low flow showerhead
    - Low flow faucet aerator
    - Air and duct sealing (electric heat only)
    - Insulation (electric heat only)
    - Efficient windows and doors
    - Air source heat pump
    - Heat pump water heaters
    - Ductless heat pumps
    - ENERGY STAR room air conditioners

Continued on Sheet 28-4

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Program: TEE – Targeted Energy Efficiency Continued

Program Description Continued

- **The Weatherization Readiness Fund:** Kentucky Power's Weatherization Readiness Fund is designed to provide supplemental funding to the Department of Energy's Weatherization Readiness Fund operated by the Kentucky Community Action network of not-for-profit community action agencies. The Weatherization Readiness Fund is intended to provide funding to make homes ready and eligible to then receive funds under the Weatherization Assistance Program. This program provides funds for community action agencies to address a homes' health, safety and structural issues that otherwise would prohibit participation in the Weatherization Assistance Program. The Company provides funding for this program through the Kentucky Community Action network of not-for-profit community action agencies. Participants under this program are eligible to receive from Kentucky Power up to $1,000 per home in supplemental funding.

Rate

No rate applies for this program.

Equipment

The Kentucky Community Action network of not-for-profit community action agencies will furnish and install, in the customer's presence, the equipment or improvements as provided by this program.

Continued on Sheet 28-5

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Program: HEIP – Home Energy Improvement Pilot Program

Availability of Service
Available on a voluntary basis until funds are depleted to individual residential customers living in single family, multi-family, or mobile homes, receiving retail electric service from the Company, and who have an electric heating, ventilation, and air conditioning (HVAC) system. "Multi-family" includes any residential unit that is not considered single family (for example, apartment, condominium, townhouse, etc.).

The Home Energy Improvement Program will be a three-year pilot ending February 27, 2028.

Program Description

- **Home Energy Audits.** The customer receives, at no additional cost to that customer, an in-home energy audit and installation of certain energy conservation measures. An energy auditor performs an in-home energy audit, identifying key areas of the home that are wasting energy and provides recommendations to make the home more energy efficient. Participants are then eligible to receive installation of select energy conservation measures recommended by the energy auditor. Eligible measures may include but are not limited to:
    - Domestic hot water pipe insulation (only customers with electric domestic hot water)
    - Water heater insulation wrap (only customers with electric domestic hot water)
    - Low-flow showerhead (only customers with electric domestic hot water)
    - Low-flow faucet aerator (only customers with electric domestic hot water)
    - Weatherstripping / caulking of doors and windows / door sweep
- **HVAC Equipment.** Customers are eligible to receive incentives, or rebates, for qualifying HVAC equipment installed by a participating dealer. Qualifying measures include ductless heat pumps and air conditioners, air-source heat pumps, central air conditioners, heat pump water heaters, ENERGY STAR room air conditioners, and smart thermostats.
- **Weatherization Measures.** Customers are eligible to receive incentives, or rebates, for qualifying weatherization measures installed by a participating dealer. Qualifying measures include attic insulation, floor insulation above crawlspace, air sealing, and duct sealing and insulation.

Incentives/Rebates
Rebates will vary depending on the efficiency rate of the measures installed. Measures may be modified by Kentucky Power's implementation contractor and Kentucky Power to reflect market conditions.

Rebates are issued to qualifying customers upon completion of the project and submission of the program application to Kentucky Power.

A complete list of the eligible equipment and incentive/rebate amounts can be found in the Program Application accessible online at KentuckyPower.com/savings/home/energy, or by contacting Kentucky Power Customer Service at 800-572-1113.

Continued on Sheet 28-6

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Program: HEIP – Home Energy Improvement Pilot Program Continued

Equipment
Home Energy Audits: The Company, or its authorized agents, will furnish and install, in the customer's presence, the energy conservation measures as recommended by the energy auditor after the in-home energy audit.

HVAC Equipment and Weatherization Measures: The customer must meet the program requirements, and it is the customer's responsibility to purchase and install the HVAC equipment and weatherization measures. Those measures must be installed by a qualified participating dealer. A complete list of qualifying participating dealers can be accessed online at KentuckyPower.com/savings/home/energy or by contacting Kentucky Power Customer Service at 800-572-1113.

Agreement
A customer program application agreement is required to participate in this program.

Rate
No rate applies for this program**.**

Continued on Sheet 28-7

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Program: CESP – Commercial Energy Solutions Pilot Program

Availability of Service
Available on a voluntary basis until funds are depleted to commercial (non-industrial and non-residential) customers in Kentucky Power's service territory.

The Commercial Energy Solutions Program will be a three-year pilot ending February 27, 2028.

Program Description

The Commercial Energy Solutions Program offers commercial customers a convenient way to receive funding for common energy efficiency measures purchased and installed at the cost of the customer. The Company will provide an energy audit at no additional cost to the customer. An inspector will perform a walk-through, identifying key areas that are wasting energy and will provide recommendations to make the building more energy efficient. Financial incentives, or rebates, will be made available to those commercial customers who implement qualified energy-efficient improvements and technologies.

Incentives, or rebates, are available for a variety of energy-saving measures in existing buildings. Qualifying customers may elect to receive incentives/rebates for eligible energy efficiency measures from a pre-qualified list provided by Kentucky Power. Incentives for custom measures will not be offered at this time. Eligible energy efficiency measures include the following:

- **Energy Efficient Lighting.** Proven qualifying technologies for which incentives, or rebates, will be provided under this program include LED lighting, daylighting controls, and occupancy sensors.

A complete list of the eligible equipment and incentive, or rebate, amounts can be found in the Program Application accessible online at KentuckyPower.com/savings/business, or by contacting Kentucky Power Customer Service at 888-710-4237.

Incentives/Rebates
The total maximum rebate amount available to qualifying commercial customers is $25,000 annually per customer account. Kentucky Power may revise incentive amounts and or the maximum incentive per customer account based upon program implementation contractor recommendations and/or overall customer response to the program.

Rebates are issued to qualifying customers upon completion of the project and submission of the program application to Kentucky Power.

Equipment
The Company, or its authorized agents, may provide support for the installation of qualifying energy-saving measures by approved program contractors. The Company, or its authorized agents, will evaluate the customer's installed energy measures for eligibility under this program. The Company, at its discretion, will determine whether the customer's installed energy-saving measures qualify for incentives/rebates under this program.

Continued on Sheet 28-8

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Program: CESP – Commercial Energy Solutions Pilot Program Continued

Agreement
A customer program application agreement is required to participate in this program.

Rate
No rate applies for this program.

Tariff S.S.C.
(System Sales Clause)

Applicable

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L. and S.L.

Rate

1. When the annual net revenues from system sales are above or below the annual base net revenues from system sales, as provided in paragraph 2 below, an additional credit or charge equal to the product of the KWHs and a system sales adjustment factor (A) shall be made, where "A", calculated to the nearest 0.0001 mill per kilowatt-hour, is defined as set forth below.

   Annual System Sales Adjustment Factor (A) = (1.0 [Ta –Tb+U/a])/Sa

   In the above formula "T" is Kentucky Power Company's (KPCo) annual net revenues from system sales in the current annual (a), base (b) periods, and "S" is the KWH sales in the current annual (a) period, all defined below. "U/a" represents any under-or-over recovery from the prior period.

   The applicable rate for service rendered on and after September 27, 2024, calculated in accordance with the above formula, is $0.00058 per kWh.

2. The net revenue from KPCo's sales to non-associated companies as reported in the FERC Energy Regulatory Commission's Uniform System of Accounts under Account 447, Sales for Resale, shall consist of and be derived as follows:

   a. KPCo's total revenues from system sales as recorded in Account 447, less b. and c. below.

   b. KPCo's total out-of-pocket costs incurred in supplying the power and energy for the sales in a. above.

      The out-of-pocket costs include all operating, maintenance, tax, transmission losses and other expenses that would not have been incurred if the power and energy had not been supplied for such sales, including demand and energy charges for power and energy supplied by Third Parties.

   c. KPCo's environmental costs allocated to non-associated utilities in the Company's Environmental Surcharge Report.

3. The base annual net revenues from system sales are: $4,425,300~~1,935,350~~.

4. Sales (S) shall be equated to the sum of (a) generation (including energy produced by generating plant during the construction period), (b) purchase, and (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) inter-system sales and less (f) total system losses.

5. The system sales adjustment factor shall be based upon actual annual revenues and costs for system sales, subject to subsequent adjustment upon final determination of actual revenues and costs.

Continued on Sheet 29-2

Tariff S.S.C. Continued
(System Sales Clause)

6. The annual System Sales Clause shall be filed with the Commission no later than August 15th of each year before it is scheduled to go into effect on Cycle 1 of the October billing cycle. The Company shall update the Annual System Sales Adjustment Factor for the period ending June 30, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

Tariff F.A.C.
(Fuel Adjustment Clause)

Applicable

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D. 2, R.S.D., G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L.

Rate

1. The fuel clause shall provide for periodic adjustment per kWh of sales equal to the difference between the fuel costs per kWh of sales in the base period and in the current period according to the following formula:

$$\text{Adjustment Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

Where F is the expense of fossil fuel in the base (b) and current (m) periods; and S is sales in the base (b) and current (m) periods, all as defined below:

2. F(b)/S(b) shall be so determined that on the effective date of the Commission's approval of the utility's application of the formula, the resultant adjustment will be equal to zero (0).

3. Fuel costs (F) shall be the most recent actual monthly cost of:

   a. Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of the fuel related substitute generation, plus

   b. The actual identifiable fossil and nuclear fuel costs [if not known--the month used to calculate fuel (F), shall be deemed to be the same as the actual unit cost of the Company generation in the month said calculations are made. When actual costs become known, the difference, if any, between fuel costs (F) as calculated using such actual unit costs and the fuel costs (F) used in that month shall be accounted for in the current month's calculation of fuel costs (F)] associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute the forced outages, plus

   c. The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases, the charges as a result of scheduled outage, and other charges for energy being purchased by the Company to substitute for its own higher cost of energy; and less

   d. The cost of fossil fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

Continued on Sheet 30-2

Tariff F.A.C. Continued
(Fuel Adjustment Clause)

Rate Continued

e. The fuel-related costs charged to the Company by PJM Interconnection LLC those costs identified in the following Billing Line Items, as may be amended from time to time by PJM Interconnection LLC: Billing Line Items 1210, 2210, 1215, 1218, 2217, 2218, 1230, 1250, 1260, 2260, 1370, 2370, 1375, 2375, 1400, 1410, 1420, 1430, 1478, 1340, 2340, 1460, 1350, 2350, 1360, 2360, 1470, 1377, 2377, 1480, 1378, 2378, 1490, 1500, 2420, 2220, 1200, 1205, 1220, 1225, 2500, 2510, 1930, 2211, 2215, 2415 and 2930.

f. All fuel costs shall be based on weighted average inventory costing.

4. Forced outages are all nonscheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the Commission, include the fuel costs of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel costs (F) in subsection (3)(a) and (b) above, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation.

5. Sales (S) shall be all kWh's sold, excluding intersystem sales. If, for any reason billed system sales cannot be coordinated with the fuel costs for the billing period, sales may be equated to: (i) generation, plus (ii) purchases, plus (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) intersystem sales referred to in subsection (3)(d) above, less (vi) total system losses. Utility used energy shall not be excluded in the determination of sales (S).

6. The cost of fossil fuel shall only include the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts for Public Utilities and Licensees, less any cash or other discounts.

7. At the time the fuel clause is initially filed, the utility shall submit copies of each fossil fuel purchase contract not otherwise on file with the Commission and all other agreements, options, amendments, modifications, and similar documents related to the procurement of fuel supply or purchased power. Any changes in the contracts or other documents, including price escalations, and any new agreements entered into after the initial submission, shall be submitted at the time they are entered into. If fuel is purchased from utility-owned or controlled sources, or the contract contains a price escalation clause, those facts shall be noted and the utility shall explain and justify them in writing. Fuel charges, which are unreasonable, shall be disallowed and may result in the suspension of the fuel adjustment clause based on the severity of the utility's unreasonable fuel charges and any history of unreasonable fuel charges. The Commission on its own motion may investigate any aspect of fuel purchasing activities covered by 807 KAR 5:056 (Fuel Adjustment Clause).

8. The monthly fuel adjustment shall be filed with the Commission no later than ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment.

9. Copies of all documents required to be filed with the Commission under 807 KAR 5:056 shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

Continued on Sheet 30-3

Tariff F.A.C. Continued
(Fuel Adjustment Clause)

10. At six (6) month intervals, the Commission shall conduct a formal review and may conduct public hearings on a utility's past fuel adjustments. The Commission shall order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustments the Commission finds unjustified due to improper calculation or application of the charge or improper fuel procurement practice.

11. Every two (2) years following the initial effective date of each utility's fuel clause, the Commission shall conduct a formal review and evaluate past operations of the clause, disallow improper expenses, and to the extent appropriate, reestablish the fuel clause charge in accordance with Section 1 (2) of 807 KAR 5:056.

12. The Commission may conduct a public hearing if the Commission finds that a hearing is necessary for the protection of a substantial interest or is in the public interest.

1.13. Resulting cost per kilowatt-hour in January 2022 to be used as the base cost in Standard Fuel Adjustment Clause is:

Fuel	January 2022	÷	$19,529,185	=	$0.03380/kWh
Sales	January 2022		577,776,513		

This, as used in the Fuel Adjustment Clause, is 3.380¢ per kilowatt-hour.

Transitional Monthly Credit

2.1. Consistent with the Settlement Agreement dated November 14, 2024, and approved by the Commission by its order dated December 13, 2024 in Case No. 2023-00008, Kentucky Power will provide to customers a transitional monthly credit to reduce the amount of future fuel costs recovered from Kentucky retail customers through this tariff as a fair and reasonable compromise of that proceeding. The credit is subject to all conditions precedent and other provisions in the Settlement Agreement.

3.2. The Company shall include an annual reconciliation of the transitional monthly credit as part of the over or under-recovery computation in the Company's Fuel Adjustment Clause filed in May 2025 and May 2026, respectively.

4.3. The applicable rates on a kWh basis are calculated as follows and will be applied to customers' January through April bills for 2025 and 2026:

	Residential ($/kWh)	All Other ($/kWh)
Transitional Credit Amount	$6,710,990	$9,825,827
Historic January through April Retail kWh	1,379,035,920	2,272,033,096
Rate	(0.00487)	(0.00432)

5.4. The applicable rates to be applied to customers' January through April bills for 2026 are subject to the Commission's issuance of a final order approving without modification the settlement agreement to be filed in the 2-year review proceeding concerning the 2022-2024 FAC Review Period.

DATE OF ISSUE: August 29, 2025January 2, 2025
DATE EFFECTIVE: Services Rendered On And After March 1, 2026December 31, 2024
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 2023-00008 Dated XXXX XX, XXXXDecember 13, 2024

Tariff P.P.A.
(Purchase Power Adjustment)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S. – I.R.P., M.W., O.L. and S.L.

Rate
The annual purchase power adjustment factor will be computed using the following formula:

1. Annual Purchase Power Net Costs (PPANC)

PPANC = N+CSIRP~~+ RKP~~+RP+GS-BPP

Where:

BPP = The annual amount of purchase power costs included in base rates, $7,988,625~~6,554,678~~.

a. N = The annual cost of power purchased by the Company through new Purchase Power Agreements and purchased power expense from avoided cost payments to net metering customers under tariff N.M.S.II above or below the $3,309,439~~1,269,331~~ included in BPP. All new purchase power agreements shall be approved by the Commission to the extent required by KRS 278.300.

b. CSIRP = The net annual cost of any credits provided to customers under Tariff C.S.-I.R.P., Tariff D.R.S., ~~Tariff V.C.S.~~ and special contracts for interruptible service above or below the $2,616,539~~1,165,983~~ included in BPP.

~~c. RKP = Rockport related items includable in Tariff PPA pursuant to the Commission approved Settlement agreement in Case No. 2017-00179:~~

~~1. Rockport deferral amount to be recovered.~~
~~Pursuant to the January 19, 2024 and February 2, 2024 Orders of the Kentucky Public Service Commission in Case No. 2023-00159 collection of this regulatory asset under this rider is temporarily suspended pending the securitization of the regulatory asset. The Company will continue to accrue carrying charges on the regulatory asset at the Company's approved weighted average cost of capital until securitized bonds are issued. If Kentucky Power is unable to issue securitized bonds, collection of this regulatory asset under this rider will be reinstated;~~

~~2. Rockport offset estimate and true-up;~~

~~3. Final (over)/under recovery associated with tariff CC following its expiration.~~

c. RP = The cost of fuel related to substitute generation less the cost of fuel which would have been used in plants suffering forced generation or transmission outages above or below the $190,571~~4,119,364~~ included in BPP.

d. GS = Net gains or losses on incidental sales of gas above or below the $1,872,076 included in BPP.

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DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
DATE EFFECTIVE: Services Rendered On And After March 1, 2026~~January 16, 2024~~
ISSUED BY: /s/ Tanner S. Wolffram~~Brian K. West~~
TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Tariff P.P.A. Continued
(Purchase Power Adjustment)

Rates

Tariff Class	$/kWh	$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.	$0.00226	--
S.G.S.-T.O.D.	$0.00195	--
M.G.S.-T.O.D.	$0.00195	--
G.S.	$0.00195	--
L.G.S., L.G.S.-T.O.D.	$0.00075	$0.34
L.G.S.-L.M.-T.O.D.	$0.00181	--
I.G.S. and C.S.-I.R.P.	$0.00075	$0.46
M.W.	$0.00156	--
O.L.	$0.000110	--
S.L.	$0.000111	--

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS, LGS-T.O.D, IGS, and CS-I.R.P. tariff classes.

The Purchase Power Adjustment factors shall be modified annually using the following formula:

~~The Purchase Power Adjustment factors shall be determined as follows:~~

For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total}) + PPA(D) \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{PPA(D) \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

Continued on Sheet 31-3

Tariff P.P.A. Continued
(Purchase Power Adjustment)

Rates Continued

Where:

1. "PPA(D)" is the actual annual retail PPA demand-related costs, plus any prior review period (over)/under recovery.

2. "PPA(E) is the actual annual retail PPA energy-related costs, plus any prior review period (over)/under recovery.

3. "BE $_{Class}$" is the ~~historic~~ forecasted annual retail jurisdictional billing kWh for each tariff class for the current year.

4. "BD $_{Class}$" is the ~~historic~~ forecasted annual retail jurisdictional billing kW for each applicable tariff class for the current year.

5. "CP $_{Class}$" is the coincident peak demand for each tariff class estimated as follows:

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.		0.022274~~22970~~%	
S.G.S.-T.O.D.		0.017461~~18187~~%	
M.G.S.-T.O.D.		0.017461~~18187~~%	
G.S.		0.017461~~18187~~%	
L.G.S., L.G.S.-T.O.D.		0.015157~~16146~~%	
L.G.S.-L.M.-T.O.D.		0.015157~~16146~~%	
I.G.S. and C.S.-I.R.P.		0.011787~~11832~~%	
M.W.		0.011468~~12350~~%	
O.L.		0.003614~~5294~~%	
S.L.		0.003595~~5375~~%	

6. "BE $_{Total}$" is the sum of the BE Class for all tariff classes.

7. "CP $_{Total}$" is the sum of the CP Class for all tariff classes.

8. The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.28~~0.40~~% and the KPSC Maintenance Fee of 0.1595~~1493~~% and other similar revenue based taxes or assessments occasioned by the Purchase Power Adjustment Rider revenues.

9. The annual PPA factors shall be filed with the Commission by August 15 of each year, with rates to begin with the October billing period, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

   Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
DATE EFFECTIVE: Services Rendered On And After March 1, 2026~~January 16, 2024~~
ISSUED BY: /s/ Tanner S. Wolffram~~Brian K. West~~
TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Tariff G.R.
(Generation Rider)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S. – I.R.P., M.W., O.L. and S.L.

Rate
The annual Generation Rider factor will be computed using the following formula:

Non-Environmental Mitchell Annual Revenue Requirement (ARR) = (RB+CWIP)(ROR)+DE+PT+OU

Where:

RB	=	Non-Environmental Rate Base for Mitchell represented by the sum of plant in service less accumulated depreciation;
CWIP	=	Construction Work in Progress for Non-Environmental Mitchell Projects;
ROR	=	Rate of Return on Non-Environmental Mitchell Rate Base;
DE	=	Depreciation Expense;
PT	=	Property Taxes;
OU	=	Cumulative difference between revenues received and actual costs for the reporting period, representing the (over) or under recovery.

Rates

Tariff Class	$/kWh	$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.	$0.00519	--
S.G.S.-T.O.D.	$0.00406	--
M.G.S.-T.O.D.	$0.00406	--
G.S.	$0.00406	--
L.G.S., L.G.S.-T.O.D.	--	$1.15
L.G.S.-L.M.-T.O.D.	$0.00352	--
I.G.S. and C.S.-I.R.P.	--	$1.63
M.W.	$0.00267	--
O.L.	$0.00084	--
S.L.	$0.00084	--

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS, LGS-T.O.D, IGS, and CS-I.R.P. tariff classes.

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DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
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TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Tariff G.R. Continued
(Generation Rider)

The Generation Rider factors shall be modified annually using the following formula:

For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{GR(E) \times (BE_{Class}/BE_{Total}) + GR(D) \times (CP_{Class}/CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{GR(E) \times (BE_{Class}/BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{GR(D) \times (CP_{Class}/CP_{Total})}{BD_{Class}}$$

Where:

1. "GR(D)" is the actual annual retail GR demand-related costs.
2. "GR(E) is the actual annual retail GR energy-related costs.
3. "BE_{Class}" is the forecasted annual retail jurisdictional billing kWh for each tariff class for the current year.
4. "BD_{Class}" is the forecasted annual retail jurisdictional billing kW for each applicable tariff class for the current year.
5. "CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:

Continued on Sheet 32-3

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
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TITLE: Director, Regulatory Services,~~Vice President, Regulatory & Finance~~
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In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Tariff G.R. Continued
(Generation Rider)

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.		0.022274%	
S.G.S.-T.O.D.		0.017461%	
M.G.S.-T.O.D.		0.017461%	
G.S.		0.017461%	
L.G.S., L.G.S.-T.O.D.		0.015157%	
L.G.S.-L.M.-T.O.D.		0.015157%	
I.G.S. and C.S.-I.R.P.		0.011787%	
M.W.		0.011468%	
O.L.		0.003614%	
S.L.		0.003595%	

6. "BE_{Total}" is the sum of the BE Class for all tariff classes.

7. "CP_{Total}" is the sum of the CP Class for all tariff classes.

8. The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.28% and the KPSC Maintenance Fee of 0.1595% and other similar revenue based taxes or assessments occasioned by the Generation Rider revenues.

9. The annual GR factors shall be filed with the Commission by February 15 of each year based on prior calendar year, with rates to begin with the April billing period, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

10. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

~~*Continued on Sheet 32-4*~~

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
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TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Tariff E.S.
(Environmental Surcharge)

Applicable

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L.

Rate

The environmental surcharge shall provide for monthly adjustments based on a percent of revenues, equal to the difference between the environmental compliance costs in the base period as provided in Paragraph 2 below and in the current period as provided in Paragraph 3 below.

The retail share of the revenue requirement will be allocated between residential and non-residential retail customers based upon their respective total revenues during the previous calendar year. The Environmental Surcharge will be implemented as a percentage of total revenues for the residential class and as a percentage of non-fuel revenues for all other customers.

The revenues to which the residential Environmental Surcharge factor are applied is the sum of the customer's Service Charge, Energy Charge(s), Demand Charge (if applicable), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Residential Energy Assistance, and Purchase Power Adjustment, and Generation Rider.

The revenues to which the all other customer Environmental Surcharge factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Kentucky Economic Development Surcharge, and Purchase Power Adjustment, and Generation Rider.

1. Monthly Environmental Surcharge Gross Revenue Requirement, E(m)

Where:	E(m)	=	CRR-BRR
	CRR	=	Current Period Revenue Requirement for the Expense Month.
	BRR	=	Base Period Revenue Requirement.

2. Base Period Revenue Requirement, BRR

BRR = The Following Monthly Amounts:

Billing Month		Base Net Environmental Costs
January	$	3,022,4183,431,790
February		2,558,3323,493,649
March		2,621,6113,165,974
April		2,519,8283,567,100
May		2,514,2843,262,891
June		2,644,9742,825,006
July		2,594,5632,815,870
August		2,741,0972,808,114
September		2,508,9952,667,203
October		2,376,6393,372,548
November		2,423,992 3,258,712
December	$	2,597,7393,306,420
	$	31,124,47237,975,278

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DATE EFFECTIVE: Services Rendered On And After March 1, 2026January 16, 2024
ISSUED BY: /s/ Tanner S. WolframBrian K. West
TITLE: Director, Regulatory ServicesVice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 2023-00159 Dated XXXX XX, XXXXJanuary 19, 2024; February 2, 2024

Tariff E.S. Continued
(Environmental Surcharge)

In accordance with the Stipulation and Settlement Agreement approved by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, the Mitchell FGD and all related associated costs are not included in base rates or the Base Revenue Requirement but will be included in the Current Period Revenue Requirement. The Mitchell FGD will be excluded from Base Rates at least until June 30, 2020.

3. Current Period Revenue Requirement, CRR

$$CRR=[((RB_{KP(c)})(ROR_{KP(c)})/12) + OE_{KP(c)} - AS]$$

Where:

$RB_{KP(c)}$	=	Environmental Compliance Rate Base for Mitchell.
$ROR_{KP(c)}$	=	Annual Rate of Return on Mitchell Environmental Compliance Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.
$OE_{KP(c)}$	=	Monthly Pollution Control Operating Expenses for Mitchell.
AS	=	Net proceeds from the sale of Title IV and CSAPR SO 2 emission allowances, ERCs, and NOx emission allowances, reflected in the month of receipt.

"KP(C)" identifies components from Mitchell Units – Current Period.

The Environmental Compliance Rate Base for Kentucky Power reflects the current cost associated with the 1997 Plan, the 2003 Plan, the 2005 Plan, the 2007 Plan, the 2015 Plan, the 2017 Plan, the 2019 Plan, and the 2021 Plan. The Environmental Compliance Rate Base for Kentucky Power should also include construction work in progress until assets are placed in service and cash working capital allowance based on the net operations and maintenance expense lead days of 53.9219.82- authorized in Case No. 2025-00257~~2023-00159~~. The Operating Expenses for Kentucky Power reflects the current operating expenses associated with the 1997 Plan, the 2003 Plan, the 2005 Plan, the 2007 Plan, the 2015 Plan, the 2017 Plan, the 2019 Plan, and the 2021 Plan.

The Rate of Return for Kentucky Power is ~~9.65~~10.0% rate of return on equity as authorized by the Commission in its Order Dated ~~January 19, 2024~~ XXXX XX, XXXX, Case No. 2025-00257~~2023-00159~~.

Net Proceeds from the sale of emission allowances and ERCs that reflect net gains will be a reduction to the Current Period Revenue Requirement, while net losses will be an increase.

The Current Period Revenue Requirement will reflect the balances and expenses as of the Expense Month of the filing.

Continued on Sheet 33-3

Tariff E.S. Continued
(Environmental Surcharge)

4. Revenue Allocation

$$\text{Residential Allocation RA(m)} = \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(m)} = \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

Where:

(m) = the expense month.
(b) = the most recent calendar year revenues

5. Environmental Surcharge Factor

$$\text{Residential Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m)} * \text{RA(m)}}{\text{KY RR(m)}}$$

$$\text{All Other Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m)} * \text{AO(m)}}{\text{KY OR(m)- KY OF(m)}}$$

Where:

Net KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.

(For purposes of this formula, Total Company Revenues do not include Non-Physical Revenues.)

RR(m) = Average Kentucky Residential Retail Revenues for the Preceding Twelve Month Period

OR(m) = Average Kentucky All Other Classes Retail Revenues for the Preceding Twelve Month Period

OF(m) = Average Kentucky All Other Classes Fuel Revenues for the Preceding Twelve Month Period.

Continued on Sheet 33-4

Tariff E.S. Continued
(Environmental Surcharge)

6. Environmental costs "E" shall be the Company's costs of compliance with the Clean Air Act and those environmental requirements that apply to coal combustion wastes and by-products, as follows:

Total Company:

- return on Title IV and CSAPR SO_2 allowance inventory
- over/under recovery balances between the actual costs incurred less the amount collected through the environmental surcharge
- costs associated with any Commission's consultant approved by the Commission
- costs associated with the consumption of Title IV and CSAPR SO_2 allowances
- costs associated with the consumption of NO_x allowances
- return on NO_x allowance inventory
- costs associated with maintaining approved pollution control equipment including material and contract labor (excluding plant labor)
- costs associated with consumables used in conjunction with approved environmental projects.
- return on inventories of consumables used in conjunction with approved environmental projects.
- return on environmental compliance rate base including construction work in progress.
- Monthly expense associated with ARO (Asset Retirement Obligations) depreciation and accretion.
- ~~Monthly expense to amortize the $1,446,998.35 regulatory asset for prudently incurred ELG (Effluent Limitation Guidelines) project costs over a two-year period to begin with July 2022 billing and conclude with June 2024 billing.~~

The Company's share of costs associated with the following environmental equipment at the Mitchell Plant:

- Mitchell Unit Nos 1 and 2 Water Injection, Low NO_x burners, Low NO_x burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and SO_3 Mitigation
- Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsum Material Handling Facilities
- Air Emission Fees
- Precipitator Modifications and Upgrades
- Coal Combustion Waste Landfill
- Bottom Ash and Fly Ash Handling
- Mercury Monitoring (MATS)
- Dry Fly Ash Handling Conversion
- Wastewater Ponds (for the Mitchell CCR compliance project) with depreciation expense calculated using a 20 percent depreciation rate approved by the Commission's July 15, 2021 and May 3, 2022 Orders in Case No. 2021-00004.

7. The monthly environmental surcharge shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments which shall include data and information as may be required by the Commission.

Decommissioning Rider
(D.R.)

Applicable

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L..

Rate

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2012-00578 and the Stipulation and Settlement Agreement dated July 2, 2013 as filed and approved by the Commission, Kentucky Power Company is to recover from retail ratepayers the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and other site-related retirement costs that will not continue in use on a levelized basis, including a weighted average cost of capital (WACC) as set in the Company's most recent Rate Case carrying cost over a 25 year period beginning with the date rates became effective in Case No. 2014-00396. The term "Retirement Costs" are defined as and shall include the net book value, materials and supplies that cannot be used economically at other plants owned by Kentucky Power, and removal costs and salvage credits, net of related ADIT. Related ADIT shall include the tax benefits from tax abandonment losses.

   *Pursuant to the January 19, 2024 and February 2, 2024 Orders of the Kentucky Public Service Commission in Case No. 2023-00159 collection under this rider is temporarily suspended pending the securitization of the regulatory asset. The Company will continue to accrue carrying charges on the regulatory asset at the Company's approved weighted average cost of capital until securitized bonds are issued. If Kentucky Power is unable to issue securitized bonds, collection under this rider will be reinstated.

   The applicable rates for service rendered on and after January 16, 2024 to be applied to the revenues described in paragraph 5 of this tariff are:

$$\text{Residential Adjustment Factor} = \frac{\$XX,XXX,XXX}{\$XXX,XXX,XXX} = 0.0000\%*$$

$$\text{All Other Classes Adjustment Factor} = \frac{\$XX,XXX,XXX}{\$XXX,XXX,XXX} = 0.0000\%*$$

2. The allocation of the actual revenue requirement (ARR) between residential and all other customers shall be based upon their respective contribution to total retail revenues for the most recent twelve month period, ending June 30 according to the following formula:

$$\text{Residential Allocation RA(y)} = \text{ARR(y)} \times \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(y)} = \text{ARR(y)} \times \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

Continued on Sheet 34-2

Decommissioning Rider Continued

Where:

(y) = the expense year;
(b) = Most recent available twelve month period ended June 30.

3. The Residential D.R. Adjustment shall provide for annual adjustments based on a percent of total revenues, according to the following formula:

$$\text{Residential D.R. Adjustment Factor} = \frac{\text{Net Annual Residential Allocation NRA(y)}}{\text{Residential Retail Revenue RR(b)}}$$

Where:

Net Annual Residential Allocation NRA(b) = Annual Residential Allocation RA(y), net of Over/(Under) Recovery Adjustment;

Residential Retail Revenue RR(b) = Annual Retail Revenue for all KY residential classes for the year (b).

4. The All Other Classes D.R. Adjustment shall provide for annual adjustments based on a percent of non-fuel revenues, according to the following formula:

$$\text{All Other Classes D.R. Adjustment Factor} = \frac{\text{Net Annual All Other Allocation NOA(y)}}{\text{All Other Classes Non-Fuel Retail Revenue ONR(b)}}$$

Where:

Net Annual All Other Allocation NOA(y) = Annual All Other Allocation OA(y), net of Over/(Under) Recovery Adjustment;

All Other Classes Non-Fuel Retail Revenue ONR(b) = Annual Non-Fuel Retail Revenue for all classes other than residential for the year (b).

5. The Revenues to which the residential Decommissioning Rider factor are applied is the sum of the customer's Service Charge, Energy Charge(s), Demand Charge (if applicable), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Residential Energy Assistance, ~~and~~ Purchase Power Adjustment, and Generation Rider.

The Revenues to which the all other customer Decommissioning Rider factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Kentucky Economic Development Surcharge, ~~and~~ Purchase Power Adjustment, and Generation Rider.

Continued on Sheet 34-3

Decommissioning Rider Continued

6. The annual Decommissioning Rider adjustments shall be filed with the Commission no later than August 15th of each year before it is scheduled to go into effect on Cycle 1 of the October billing cycle, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

~~*Continued on Sheet 34-4*~~

Securitized Surcharge Rider
(S.S.R.)

Applicable
To all retail electric customers.

Rate

1. Pursuant to the financing order of the Kentucky Public Service Commission in Case No. 2023-00159, Kentucky Power Company is to recover from retail ratepayers the costs approved for securitized bond financing by the Commission. Terms not defined in this rider shall have the meanings ascribed to those terms in that financing order.

   This rider is designed to recover from all retail electric customers the amounts necessary to service, repay and administer customer-backed securitized bonds associated with the approved securitized costs pursuant to the terms of the financing order of the Kentucky Public Service Commission in Case No. 2023-00159.

   This rider shall remain in effect until the complete repayment and retirement of any securitized bonds, or refunding bonds, associated with the approved securitized costs, together with ongoing financing costs. Upon issuance of a series of securitized bonds, this schedule is irrevocable and associated securitized surcharges are nonbypassable for the full term of that series of securitized bonds.

2. The Periodic Payment Requirement (PPR) is the required periodic payment for a given period due under the securitized bonds as further defined in the financing order.

3. Periodic Billing Requirement (PBR) shall be the aggregate dollar amount of securitized surcharges that must be billed during a given period so that the securitized surcharge collections will be sufficient to meet the sum of all PPR for that period, given: (i) forecast usage and revenue data, excluding the securitized surcharge, for the period; (ii) forecast uncollectibles for the period; and (iii) forecast lags in collection of billed securitized surcharges for the period.

4. The PBR for a given period shall be the sum of (a) the PBR for residential customers for the period (y) (Residential PBR Allocation (y)) and (b) the PBR for all other retail electric customers (non-residential retail electric customers) for the period (y) (Non-Residential PBR Allocation (y)).

5. The Residential PBR Allocation (y) shall be recovered from residential customers through application of the Residential S.S.R. Adjustment Factor to all charges on each residential customers bill for electric service, except for environmental surcharge (ES) and Decommissioning Rider (DR) charges, nonrecurring charges, and pass through charges as discussed and defined in the financing order in Case No. 2023-00159. The charges to which the Residential S.S.R. Adjustment Factor currently applies, based on that definition, are the sum of the customer's Service Charge, Demand Charge, Energy Charge(s), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Residential Energy Assistance, ~~and~~ Purchase Power Adjustment, and Generation Rider.

Continued on Sheet 35-2

DATE OF ISSUE: ~~November 15, 2024~~August 29, 2025
DATE EFFECTIVE: Services Rendered On And After ~~November 26, 2024~~March 1, 2026
ISSUED BY: /s/ Tanner S. Wolffram
TITLE: Director, Regulatory Services
By Authority of an Order of the Public Service Commission
In Case No.: ~~XXXX XXXXX~~ 2025-00257 Dated XXXX XX, XXXX

Securitized Surcharge Rider Continued
(S.S.R.)

6. The Non-Residential PBR Allocation (y) shall be recovered through application of the Non-Residential S.S.R. Adjustment Factor to all charges on each non-residential retail electric customers bill for electric service, except for charges for base fuel costs and fuel cost adjustments, and environmental surcharge (ES) and Decommissioning Rider (DR) charges, nonrecurring charges, and pass through charges as discussed and defined in the financing order in Case No. 2023-00159. The charges to which the Non-Residential S.S.R. Adjustment Factor currently applies, based on that definition, are the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Kentucky Economic Development Surcharge, ~~and~~ Purchase Power Adjustment, and Generation Rider.

7. The Residential S.S.R. Adjustment Factor (y) shall be calculated according to the following formula:

$$\text{Residential S.S.R. Adjustment Factor (y)} = \frac{\text{Residential PBR Allocation (y)}}{\text{Expected Residential Retail Revenue (y)}}$$

Where:

(y)	=	the given period
Expected Residential Retail Revenue (y)	=	Expected retail revenue for the period (y) from charges to which the Residential S.S.R. Adjustment Factor will apply in the period (y).

8. The Non-Residential S.S.R. Adjustment Factor shall be calculated according to the following formula:

$$\text{Non-Residential S.S.R. Adjustment Factor (y)} = \frac{\text{Non-Residential PBR Allocation (y)}}{\text{Expected Non-Residential Non-Fuel Retail Revenue NR(y)}}$$

Where:

(y)	=	the given period
Expected Non-Residential Non-Fuel Retail Revenue NR(y)	=	Expected non-fuel retail revenue for all non-residential retail electric customers for the period (y) from charges or portions of charges to which the Non-Residential S.S.R. Adjustment Factor will apply in the period (y).

9. The Residential PBR Allocation (y) shall be calculated by taking the sum of the residential true-up for the given period (y) (Residential True-up (y)) and the Residential PPR Allocation (y) and adjusting the sum to reflect both the projection of uncollectible securitized surcharges from residential customers and a projection of payment lags between the billing and collection of securitized surcharges from residential retail customers based upon the most recent experience regarding collection of securitized surcharges from residential customers.

Continued on Sheet 35-3

Securitized Surcharge Rider Continued
(S.S.R.)

10. The Non-Residential PBR Allocation (y) shall be calculated by taking the sum of the nonresidential retail electric customers true-up for the given period (y) (Non-Residential True-up (y)) and the Non-Residential PPR Allocation (y) and adjusting the sum to reflect both the projection of uncollectible securitized surcharges from non-residential retail electric customers and a projection of payment lags between the billing and collection of securitized surcharges from non-residential retail electric customers based upon the most recent experience regarding collection of securitized surcharges from non-residential retail electric customers.

11. The PPR for a given period, less the balance of the excess-funds subaccount not already accounted as part of the true-ups in paragraphs 12 and 13 and those portions of the PPR, if any, that will be collected as part of the true-ups in paragraphs 12 and 13 (PPR(y)), shall be allocated between residential customers and non-residential retail electric customers based upon their respective contributions to total retail revenues from the charges to which the Residential S.S.R. Adjustment Factor and Non-Residential S.S.R. Adjustment Factor applied and fuel costs for non-residential retail electric customers, according to the following formula:

$$\text{Residential PPR Allocation (y)} = \text{PPR(y)} \times \frac{\text{Residential Retail Revenue (b)}}{\text{KY Retail Revenue (b)}}$$

$$\text{Non-Residential PPR Allocation (y)} = \text{PPR(y)} \times \frac{\text{Non-Residential Retail Revenue (b)}}{\text{KY Retail Revenue (b)}}$$

Where:

(y)	=	the given period
(b)	=	Most recent available twelve-month period ended December 31 or June 20
Residential Retail Revenue (b)	=	Retail revenue for residential retail electric customers for the period (b) from charges to which Residential S.S.R. Adjustment Factor applied in the period (b) (or to which it would have applied if the adjustment factor was not applicable during all or a portion of the period).
Non-Residential Retail Revenue (b)	=	Retail revenue for all non-residential retail electric customers for the period (b) from charges to which the Non-Residential S.S.R. Adjustment Factor applied (or to which it would have applied if the adjustment factor was not applicable during all or a portion of the period) and charges for base fuel and pursuant to the fuel adjustment clause.
KY Retail Revenue (b)	=	Residential Retail Revenue (b) + Non-Residential Retail Revenue (b).

12. The Residential True-up (y) shall be calculated by subtracting the cumulative revenues collected from the Residential S.S.R. Adjustment Factor through the preceding period from the cumulative Residential PPR Allocation for all periods through the preceding period, in which the preceding period is the period ending on the date on which Residential S.S.R. Adjustment Factor (y) goes into effect.

Continued on Sheet 35-4

Securitized Surcharge Rider Continued
(S.S.R.)

13. The Non-Residential True-up (y) shall be calculated by subtracting the cumulative revenues collected from the Non-Residential S.S.R. Adjustment Factor through the preceding period from the cumulative Non-Residential PPR Allocation for all periods through the preceding period, in which the preceding period is the period ending on the date on which Non-Residential S.S.R. Adjustment Factor (y) goes into effect.

14. Notwithstanding the foregoing:

    A. the Residential S.S.R. Adjustment Factor to be used for the applicable true up filing shall be the greater of (i) the Residential S.S.R. Adjustment Factor (y), where (y) is the period beginning on the date on which the applicable true-up adjustment would go into effect and ending on the next payment date after the effective date of each true-up adjustment (Calculation Period A), and (ii) the Residential S.S.R. Adjustment Factor (y), where (y) is the period beginning on the date on which the applicable true-up adjustment would go into effect and ending on the second payment date after the effective date of such true-up adjustment (Calculation Period B);

    B. the Non-Residential S.S.R. Adjustment Factor to be used for the applicable true-up filing shall be the greater of (i) the Non-Residential S.S.R. Adjustment Factor (y), where (y) us Calculation Period A, and (ii) the Non-Residential S.S.R. Adjustment Factor (y), where (y) is Calculation Period B;

    C. the Residential PBR Allocation (y) referenced in paragraph 5 shall be with respect to the same period (y) as used for the Residential S.S.R. Adjustment Factor (y) selected under clause (A) above; and

    D. the Non-Residential PBR Allocation (y) referenced in paragraph 6 shall be with respect to the same period (y) as used for the Non-Residential S.S.R. Adjustment (y) selected under clause (B) above.

15. The initial Residential S.S.R. Adjustment Factor and Non-Residential S.S.R. Adjustment Factor shall be filed on the day following the pricing of each series of securitized bonds, shall be calculated based on the formulas in paragraphs 7 and 8, respectively, and shall become effective the first billing cycle following the closing of the securitized bonds. The Residential S.S.R. Adjustment Factor and Non-Residential S.S.R. Adjustment Factor shall initially be adjusted on March 1, 2026 and thereafter be adjusted at least semi-annually (every six months) along with all the necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

    Quarterly true-ups will begin 12 months prior to the scheduled final payment date for the latest maturing tranche of securitized bonds of a particular series.

    Interim Securitized Surcharge Rider adjustments may be filed with the Commission outside of the standard semi-annual or quarterly timeframe in order to correct for over- or under-collection to be submitted no later than 10 days before the rate is to be effective.

    Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

Continued on Sheet 35-5

Securitized Surcharge Rider Continued
(S.S.R.)

16. The applicable rates for service rendered on and after June 30, 2025 to be applied to the revenues described in paragraphs 5 and 6 of this tariff are:

Residential S.S.R. Adjustment Factor	=	$12,162,339 / $172,017,997	=	7.0704%
Non-Residential S.S.R. Adjustment Factor	=	$15,620,679 / $142,477,952	=	10.9636%

Federal Tax Cut Tariff
(F.T.C.)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L.

Rate

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2023-00159, Kentucky Power Company is to credit to retail ratepayers the approved annual amount of excess accumulated deferred federal income taxes (ADIT) beginning January 16, 2024.

2. The Company shall amortize the calendar year retail Generation and Distribution related Protected Excess ADIT of $1,410,730~~1,969,031~~ to support the rate credits provided to customers through this tariff.

3. ~~Subject to Commission approval of the Company's application for a financing order authorizing the Company to securitize the Rockport Deferral Regulatory Asset, Tariff P.P.A. Under-Recovery Regulatory Asset, and Storm Expense Deferral Regulatory Assets identified in the Company's Application in 2023-00159 (collectively, the "Non-Decommissioning Rider Regulatory Assets"), and subject to the Company's issuance of securitized bonds that include the Non-Decommissioning Rider Regulatory Assets, t~~The Company shall provide customers with the ADIT benefit related to Non-Decommissioning Rider Regulatory Assets (defined as the Rockport Deferral Regulatory Asset, Tariff P.P.A. Under-Recovery Regulatory Asset, and Storm Expense Deferral Regulatory Assets) approved for securitization through this tariff, at its Commission-approved WACC. The ADIT benefit described in this paragraph will be annually trued-up to address over/(under) recovery pursuant to the procedure described in paragraph ~~7~~8 of this tariff.

~~3.~~4. Upon receipt of a Private Letter Ruling from the IRS affirming the Company's analysis that excluding its NOLC adjustment from rates would constitute a normalization violation, recovery of the NOLC regulatory asset established in accordance with the Commission's January 19, 2024 Order in Case No. 2023-00159 over a three-year period starting XXXX XX, XXXX.

~~4.~~5. The Company shall include a final reconciliation of the retail Generation and Distribution related Unprotected Excess ADIT as part of the over or under-recovery computation in the October 2024 Federal Tax Cut Tariff adjustment filing.

~~5.~~6. The applicable rates on a kWh basis are as follows:

Residential ($/kWh)	All Other ($/kWh)
$(0.00068)	$(0.00047)

Continued on Sheet 36-2

DATE OF ISSUE: August 29, 2025~~February 8, 2024~~
DATE EFFECTIVE: Services Rendered On And After March 1, 2026~~January 16, 2024~~
ISSUED BY: /s/ Tanner S. Wolfram~~Brian K. West~~
TITLE: Director, Regulatory Services~~Vice President, Regulatory & Finance~~
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257~~2023-00159~~ Dated XXXX XX, XXXX~~January 19, 2024~~

Federal Tax Cut Tariff Continued
(F.T.C.)

~~6.~~7. The allocation of the Annual Revenue Requirement (ARR) which consists of the retail Generation and Distribution related Protected Excess ADIT, the ADIT benefits related to the securitized Non-Decommissioning Rider Regulatory Assets and any over or under-recovery based upon actual information for prior periods between residential and all other customers shall be based upon their respective contribution to total retail revenues, according to the following formula:

$$\text{Residential Allocation } RA(y) = AC(y) \times \frac{\text{KY Residential Retail Revenue } RR}{\text{KY Retail Revenue } R}$$

$$\text{All Other Allocation } OA(y) = AC(y) \times \frac{\text{KY All Other Classes Retail Revenue } OR}{\text{KY Retail Revenue } R}$$

Where:

(y)	=	the credit year;
RR	=	$263,446,618;
OR	=	$347,727,039; and
R	=	$611,173,657.

~~7.~~8. The annual Federal Tax Cut Tariff adjustments shall be filed with the Commission no later than October 15th of each year before it is scheduled to go into effect on Cycle 1 of the December billing cycle, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

~~8.~~9. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

Tariff C.F.F.
(City's Franchise Fee)

Availability of Service

Where a city or town within Kentucky Power's service territory requires the Company to pay a percentage of revenues from certain customer classifications collected within such city or town for the right to erect the Company's poles, conductors, or other apparatus along, over, under, or across such city's or town's streets, alleys, or public grounds, the Company shall increase the rates and charges to such customer classifications within such city or town by a like percentage. The aforesaid charge shall be separately stated and identified on each affected customer's bill.

U.G.R.T.
(Utility Gross Receipts Tax)
(School Tax)

Applicable
To all Tariff Schedules.

Rate
This tariff schedule is applied as a rate increase pursuant to KRS 160.617 to all other tariff schedules for the recovery by the utility of the utility gross receipts license tax imposed by the applicable school district pursuant to KRS 160.613 with respect to the customer's bill. The current utility gross receipts license tax for school imposed by a school district may not exceed 3%. The utility gross receipts license tax shall appear on the customer's bill as a separate line item.

K.S.T.
(Kentucky Sales Tax)

Applicable
To all Tariff Schedules.

Rate
This tariff schedule is applied as a rate increase to all other applicable tariff schedules for the recovery by the utility pursuant to KRS 139.210 of the Kentucky Sales Tax imposed by KRS 139.200 for all customers not exempted by KRS 139.470(7). For any other exempt customers, an exemption certification must be received and on file with the Company. The Kentucky Sales Tax rate is currently imposed by the Commonwealth of Kentucky at the rate of 6%. The Kentucky Sales Tax shall appear on the customer's bill as a separate line item.

Sales of electricity under Tariff R.S. are exempt from sales tax only if the service is to the customer's place of domicile as defined by KRS 139.470(7)(b). Kentucky Power may retroactively charge a customer, under the parameters of KRS 278.225, for all applicable sales tax the Department of Revenue determines is due for service that is not exempt. It is the customer's responsibility to file all necessary documentation, including Form 51A380 (1-23), when notified by the Company, establishing the customer's place of domicile. In such a case, any exemption will become effective with the customer's first full billing cycle after the customer's delivery of a properly executed Form 51A380 (1-23).

Exhibit F Index

Description	Page
Request for Publication of Notice	2
Listing of Newspapers	3
Full Notice	4-7
Certification of Compliance with Notice and Posting Requirements	8-10

Lerah M Kahn

From: Michelle Caldwell
Sent: Wednesday, August 20, 2025 9:57 AM
To: Holly Willard
Cc: Tanner S Wolffram; Lerah M Kahn; TERESA THOMPSON; J.D. Cullop; Stevi N Cobern; Glass, Katie; JEFFREY D NEWCOMB; David Thompson; Michael J Schuler
Subject: [2025-00257 Rate Base Case] Newspaper Notice
Attachments: KENTUCKY POWER - REVISED 3.pdf

The attached proof is approved.

Please begin running the notice in all newspapers within our service territory on August 22, 2025. The notice needs to run consecutively for three weeks.

Thank you,
Michelle

KENTUCKY POWER
AEP

MICHELLE CALDWELL | **REGULATORY CASE COORDINATOR SR**
MMCALDWELL@AEP.COM | D:606.327.2652
1645 WINCHESTER AVENUE, ASHLAND, KY 41101

List of Newspapers in Kentucky Power's Service Territory

Newspaper Name	County
Ashland Daily Independent	Boyd and Carter
Booneville Sentinel	Owsley
Carter County Times	Carter
Greenup Gazette	Greenup
Hazard Herald	Perry
Hindman Troublesome Creek Times	Knott
Hyden Leslie Co. News	Leslie
Inez Mountain Citizen	Martin
Jackson Times Voice	Breathitt
Louisa Big Sandy News	Lawrence
Manchester Enterprise	Clay
Paintsville Herald	Johnson
Pikeville Appalachian News Express	Pike
Prestonsburg Floyd County Chronicle & Times	Floyd
Rowan County News	Rowan
Salyersville Independent	Magoffin
Sandy Hook Elliott County News	Elliott
Vanceburg Lewis County Herald	Lewis
West Liberty Licking Valley Courier	Morgan
Whitesburg Mountain Eagle	Letcher

NOTICE

PLEASE TAKE NOTICE that on August 29, 2025, Kentucky Power Company ("Kentucky Power" or the "Company") will file with the Public Service Commission of Kentucky (the "Commission") in Case No. 2025-00257 an application pursuant to Chapter 278 of the Kentucky Revised Statutes for authorization to adjust the rates it charges its customers for services rendered on and after March 1, 2026. Kentucky Power is also seeking authority to revise the terms, conditions, and other requirements of service, including changes to miscellaneous charges. If approved, Kentucky Power will apply the new rates and terms and conditions of service to all customer bills for services rendered on and after March 1, 2026, to recover the costs of providing service to its customers on and after that date.

Kentucky Power also proposes to create a new Generation Rider to collect the non-environmental Mitchell capital plant balances that are currently in base rates, including associated depreciation expense, and the capital costs associated with making the investments necessary to continue receiving capacity and energy from its coal-fired Mitchell Plant after December 31, 2028. Kentucky Power also proposes to update its depreciation rates, except for depreciation rates for the Mitchell Plant.

Kentucky Power further proposes to create a new voluntary FlexPay Program. FlexPay is a prepayment program associated with deployment of the Company's Advanced Metering Infrastructure that allows customers to pay as they go. Kentucky Power also proposes to establish two-tiered residential customer charges and block energy rates. Additionally, Kentucky Power is proposing to consolidate Tariffs COGEN/SPP I and COGEN/SPP II into Tariff COGEN/SPP by deleting Tariff COGEN/SPP I in its entirety and making the updates identified below to Tariff COGEN/SPP II along with corresponding internal reference changes. Kentucky Power is also deleting Tariff V.C.S. in its entirety.

In addition to the rate changes described below, Kentucky Power has made changes to the text of certain tariffs. Where the text changes to the tariff are substantive in nature, the proposed language change is described below.

Tariff Changes

Terms and Conditions of Service

5. Payments

Bills will be rendered by the Company to the Customer monthly or in accordance with the tariff selected applicable to the Customer's service.

A. Equal Payment Plan (Budget)

[…]

If a customer who is currently enrolled in the Equal Payment Plan elects to take service under Tariff N.M.S. II, such customer will be removed from the Equal Payment Plan and restored to regular billing. *Additionally, if a customer who is currently enrolled in the Equal Payment Plan elects to take service under Tariff FlexPay, such customer will be removed from the Equal Payment Plan and billed on a pay as they use basis.*

B. Average Monthly Payment Plan

[…]

If a customer who is currently enrolled in the AMP Plan elects to take service under Tariff N.M.S. II, such customer will be removed from the AMP Plan and restored to regular billing. *Additionally, if a customer who is currently enrolled in the AMP Plan elects to take service under Tariff FlexPay, such customer will be removed from the AMP Plan and billed on a pay as they use basis.*

C. All Payments

[…]

Delayed Payment Charge

The tariffs of the Company are met if the account of the Customer is paid within the time limit specified in the tariff applicable to the Customer's service. *Residential customers are not subject to a delayed payment charge.* On all non-residential accounts not so paid, an additional charge of 5% of the unpaid balance will be applied. Any one delayed payment charge billed against the Customer for non-payment of bill or any one forfeited discount applied against the Customer for non-payment of bill may be remitted, provided the Customer's previous accounts are paid in full and provided no delayed payment charge or forfeited discount has been remitted under this clause during the preceding six months.

19. Special Charges

a. Reconnection and Disconnect Charges
In cases where the Company has discontinued service as herein provided for, the Company reserves the right to assess a reconnection charge pursuant to 807 KAR 5:006, Section 9 (3)(b), payable in advance, in accordance with the following schedule. However, those Customers qualifying for Winter Hardship Reconnection under 807 KAR 5:006 Section 16 shall be exempt from the reconnect charges.

Reconnect for nonpayment during regular hours *for non-remote reconnection meters*	*$54.11~~4.70~~*
Reconnect at the end of the day (no "Call Out" required) *for non-remote reconnection meters*	*$137.20~~30.00~~*
Reconnect for nonpayment when a "Call Out" is required prior to 8:00 p.m. *for non-remote reconnection meters* (A "Call Out" is when an employee must be called in to work on overtime basis to make the reconnect trip. Reconnection for nonpayment will not be made when a "Call Out" after 8:00 p.m. is required)	*$137.20~~95.00~~*
Reconnect for nonpayment when double time is required (Sunday and Holiday) *for non-remote reconnection meters*	*$178.75~~124.00~~*
Reconnect for nonpayment for meters with remote reconnection capability	*$0.00*
Termination or field trip	*$54.11~~4.70~~*

The reconnection charge for all Customers where service has been disconnected for fraudulent use of electricity will be the actual cost of the reconnection.

b. Meter Read Check
Pursuant to 807 KAR 5:006, Section 9(3)(d) in cases where a customer requests a meter be reread, and the second reading shows the original reading was correct, the Customer will be charged a fee of *$54.11~~21.00~~* to cover the handling cost.

c. Returned Check Charge
In cases where a customer pays by check, which is later returned as unpaid by the bank for any reason, the Customer will be charged a fee of *$6.60~~14.65~~* to cover the handling costs.

d. Meter Test Charge
Where test of a meter is made upon written request by the Customer pursuant to 807 KAR 5:006, Section 19, the Customer will be charged *$74.88~~48.00~~* if such test shows that the meter was not more than two percent (2%) fast.

21. Alerts and Subscriptions

[…]

Customers interested in receiving mobile alerts from Kentucky Power may sign up for the service through the Company's website at www.kentuckypower.com. The full terms and conditions of participating in the Kentucky Power Mobile Alert Service are included on the Company's website. Customers wishing to participate in Kentucky Power's Mobile Alert Service and to receive alerts via e-mail should add communications@kentuckypower-~~mail~~*aep.com and communications@aep-email.com* to the customer's email address book or spam filter to avoid alert communications from Kentucky Power being directed to spam. Customers are advised to contact their e-mail service provider for instructions on how to add addresses to an address book or spam filter if needed.

Changes to Applicable Adjustment Clause Provisions

Due to the addition of the Generation Rider, the Company is updating the list of applicable adjustment clauses for each tariff class as follows:

Changes Applicable to Tariff R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D.2, and R.S.D:

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	*Sheet No. 32*
Environmental Surcharge	Sheet No. 3~~2~~*3*
Decommissioning Rider	Sheet No. 3~~3~~*4*
Securitized Surcharge Rider	Sheet No. 3~~4~~*5*
Federal Tax Cut Tariff	Sheet No. 3~~5~~*6*
City's Franchise Fee	Sheet No. 3~~6~~*7*
School Tax	Sheet No. 3~~7~~*8*

Changes Applicable to Tariff G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., M.W., and C.S.-I.R.P.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	*Sheet No. 32*
Environmental Surcharge	Sheet No. 3~~2~~*3*
Decommissioning Rider	Sheet No. 3~~3~~*4*
Securitized Surcharge Rider	Sheet No. 3~~4~~*5*
Federal Tax Cut Tariff	Sheet No. 3~~5~~*6*
City's Franchise Fee	Sheet No. 3~~6~~*7*
School Tax	Sheet No. 3~~7~~*8*

Changes Applicable to Tariff O.L. and S.L.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Generation Rider	*Sheet No. 32*
Environmental Surcharge	Sheet No. 3~~2~~*3*
Decommissioning Rider	Sheet No. 3~~3~~*4*
Securitized Surcharge Rider	Sheet No. 3~~4~~*5*
Federal Tax Cut Tariff	Sheet No. 3~~5~~*6*
City's Franchise Fee	Sheet No. 3~~6~~*7*
School Tax	Sheet No. 3~~7~~*8*

Changes Applicable to Tariff R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D.2, and R.S.D.

Tariff R.S.
(Residential Service)

Rate (Tariff Codes 015, 017, 022)

Service Charge*	~~$20.00~~	~~per month~~
Tier 1 (0-2,000 kWh)	*$26.00*	*per month*
Tier 2 (over 2,000 kWh)	*$40.00*	*per month*
Energy Charge**	~~12.785¢~~	~~per kWh~~
Block 1 (0-600 kWh)	*15.750¢*	*per kWh*
Block 2 (over 600 kWh)	*12.606¢*	*per kWh*

**Customers will only be charged either the Tier 1 or Tier 2 service charge based on the customer's total energy usage for the billing period.*

***Customers will be charged the Block 1 energy charge for all usage up to 600 kWh and the Block 2 energy charge for all usage above 600 kWh for the billing period.*

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5~~2-4~~. *Residential customers are not subject to a delayed payment charge.*

Tariff R.S. – L.M. – T.O.D.
(Residential Service Load Management Time-of-Day)

Rate (Tariff Codes 028, 030, 032, 034)

Service Charge	~~$23.00~~ *29.00*	per month
Energy Charge		
All kWh used during on-peak billing period	~~17.335~~ *19.962¢*	per kWh
All kWh used during off-peak billing period	9.317¢	per kWh

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. Residential customers are not subject to a delayed payment charge.

Separate Metering Provision
Customers who use electric thermal storage space heating and water heaters which consume energy only during off-peak hours specified by the Company, or other automatically controlled load management devices such as space and/or water heating equipment that use energy only during off-peak hours specified by the Company, shall have the option of having these approved load management devices separately metered. The service charge for the separate meter shall be $*4.45*~~4.30~~ per month.

Tariff R.S. – T.O.D.
(Residential Service Time-of-Day)

Rate (Tariff Code 036)

Service Charge	~~$23.00~~ *29.00*	per month
Energy Charge		
All kWh used during on-peak billing period	~~17.335~~ *19.962¢*	per kWh
All kWh used during off-peak billing period	9.317¢	per kWh

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5~~2-4~~. *Residential customers are not subject to a delayed payment charge.*

Tariff R.S. – T.O.D.2
(Experimental Residential Service Time-of-Day 2)

Rate (Tariff Code 027)

Service Charge	~~$23.00~~ *29.00*	per month
Energy Charge		
All kWh used during Summer on-peak billing period	~~18.291~~ *20.702¢*	per kWh
All kWh used during Winter on-peak billing period	~~13.426~~ *17.881¢*	per kWh
All kWh used during off-peak billing period	~~12.167~~ *12.980¢*	per kWh

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. Residential customers are not subject to a delayed payment charge.

Tariff R.S.D.
(Residential Demand-Metered Electric Service)

Monthly Rate (Tariff Code 018)

Service Charge	~~$23.00~~ *26.00*	per customer
Energy Charge		
All kWh used during on-peak billing period	~~9.861~~ *14.464¢*	per kWh
All kWh used during off-peak billing period	9.317¢	per kWh
Demand Charge	~~$5.90~~*8.01*	for each kW of monthly billing demand

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5~~2-4~~. *Residential customers are not subject to a delayed payment charge.*

Changes Applicable to Tariff G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., and M.W.

Tariff G.S.
(General Service)

Rate

Tariff Code	Service Voltage	Demand Charge ($/kW)	First 4,450 kWh (¢kWh)	Over 4,450 kWh (¢kWh)	Monthly Service Charge ($)
211, 212, 215, 216, 218	Secondary	*13.24~~8.36~~*	*14.562~~13.060~~*	*11.853~~11.581~~*	*31.00~~28.00~~*
217, 220	Primary	*11.85~~7.56~~*	*12.887~~11.558~~*	*10.543~~10.301~~*	*140.00~~120.00~~*
236	Subtransmission	*9.07~~5.84~~*	*11.742~~10.531~~*	*9.618~~9.397~~*	460.00

The Demand Charge shall apply to all monthly billing demand in excess of 10 kW.

Rate (Tariff Code 214)

Service Charge	*$31.00 ~~28.00~~*	per month
Energy Charge	*15.950~~14.015~~¢*	per kWh

Rate (Tariff Codes 223 and 225)

Service Charge	*$31.00~~28.00~~*	per month

CONTINUED

Energy Charge		
All kWh used during on-peak billing period	~~19.211~~*22.953¢*	per kWh
All kWh used during off-peak billing period	~~9.269~~*9.493¢*	per kWh

Rate (Tariff Codes 204 (Metered) and 213 (Unmetered))

Customer Charge	*$17.00*~~15.00~~	per month
Energy Charge		
First 4,450 kWh per month	~~13.060~~*14.562¢*	per kWh
All Over 4,450 kWh per month	~~11.581~~*11.853¢*	per kWh

Tariff S.G.S.-T.O.D.
(Small General Service Time-of-Day Service)

Rate (Tariff Code 227)

Service Charge	*$31.00*~~28.00~~	per month
Energy Charge		
All kWh used during Summer on-peak billing period	~~20.185~~*23.244¢*	per kWh
All kWh used during Winter on-peak billing period	~~14.461~~*22.547¢*	per kWh
All kWh used during off-peak billing period	~~13.034~~*14.004¢*	per kWh

Tariff M.G.S.-T.O.D.
(Medium General Service Time-of-Day)

Rate (Tariff Code 229)

Service Charge	*$31.00*~~28.00~~	per month
Energy Charge		
All kWh used during on-peak billing period	~~19.211~~*22.953¢*	per kWh
All kWh used during off-peak billing period	~~9.269~~*9.493¢*	per kWh

Tariff L.G.S.
(Large General Service)

Rate

	Service Voltage			
	Secondary	**Primary**	**Subtransmission**	**Transmission**
Tariff Code	240, 242, 260	244, 246, 264	248, 268	250, 270
Service Charge per Month	*$111.00*~~97.00~~	*$166.00*~~145.00~~	*$849.00*~~750.00~~	*$849.00*~~750.00~~
Demand Charge per kW	*$15.76*~~13.84~~	*$13.93*~~12.23~~	*$9.64*~~8.46~~	*$9.43*~~8.28~~
Excess Reactive Charge per KVA	$3.46	$3.46	$3.46	$3.46
Energy Charge per kWh	~~8.966~~*10.238¢*	~~8.120~~*9.339¢*	~~6.292~~*7.127¢*	~~6.198~~*7.008¢*

Rate (Tariff Code 251)

Service Charge	*$111.00*~~97.00~~	per month
Energy Charge		
All kWh used during on-peak billing period	~~16.700~~*20.310¢*	per kWh
All kWh used during off-peak billing period	~~9.407~~*9.677¢*	per kWh

Tariff L.G.S.-T.O.D.
(Large General Service – Time of Day)

Rate

	Service Voltage			
	Secondary	**Primary**	**Subtransmission**	**Transmission**
Tariff Code	256	257	258	259
Service Charge per Month	*$111.00*~~97.00~~	*$166.00*~~145.00~~	*$849.00*~~750.00~~	*$849.00*~~750.00~~
Demand Charge per kW	*$13.10*~~9.33~~	*$10.78*~~7.91~~	*$4.97*~~4.39~~	*$4.90*~~4.32~~
Excess Reactive Charge per KVA	$3.46	$3.46	$3.46	$3.46
On-Peak Energy Charge per kWh	~~13.416~~*14.753¢*	~~12.820~~*14.084¢*	~~12.646~~*13.880¢*	~~12.499~~*13.709¢*
Off-Peak Energy Charge per kWh	~~6.906~~*7.170¢*	~~6.734~~*6.958¢*	~~6.684~~*6.894¢*	~~6.642~~*6.840¢*

Tariff I.G.S.
(Industrial General Service)

Rate

	Service Voltage			
	Secondary	**Primary**	**Subtransmission**	**Transmission**
Tariff Code	356	358/370	359/371	360/372
Service Charge per Month	$276.00	$276.00	$794.00	$1,353.00
Demand Charge per kW				
Of monthly on-peak billing demand	*$30.52*~~26.99~~	*$28.33*~~24.94~~	*$19.55*~~17.36~~	*$19.16*~~17.00~~
Of monthly off-peak billing demand	*$2.08*~~1.84~~	*$2.01*~~1.78~~	*$1.98*~~1.75~~	*$1.96*~~1.73~~
Energy Charge per kWh	~~3.924~~*4.537¢*	~~3.775~~*4.331¢*	~~3.732~~*4.269¢*	~~3.695~~*4.216¢*

Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand.....$0.69/KVAR

Minimum Demand Charge
The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:

Secondary	**Primary**	**Subtransmission**	**Transmission**
$31.91	*$29.68*	*$20.88*	*$20.46*
~~25.68~~ / kW	~~23.68~~ / kW	~~16.12~~ / kW	~~15.77~~ / kW

Tariff M.W.
(Municipal Waterworks)

Rate (Tariff Code 540)

Service Charge	*$28.00*~~25.00~~	per month
Energy Charge		
All kWh used per month	~~11.841~~*13.979¢*	per kWh

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the sum of the service charge plus *$10.22*~~9.55~~ per KVA as determined from customer's total connected load.

Changes Applicable to Tariffs O.L. and S.L.

Tariff O.L.
(Outdoor Lighting)

Rate

A. Overhead Lighting Service

	Tariff Code	**Watts**	**Rate**	
High Pressure Sodium	094	100 (9,500 Lumens)	*$11.84*~~10.25~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	113	150 (16,000 Lumens)	*$13.50*~~11.69~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	097	200 (22,000 Lumens)	*$16.36*~~14.17~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	103	250 (28,000 Lumens)	*$23.32*~~20.19~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	098	400 (50,000 Lumens)	*$25.84*~~22.38~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	Tariff Code	**Watts**	**Rate**	
Mercury Vapor	093	175 (7,000 Lumens)	*$15.09*~~13.07~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	095	400 (20,000 Lumens)	*$25.97*~~22.49~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	Tariff Code	**Lumens**	**Rate**	
LED	150	6,000-10,000	*$8.65*~~7.49~~	per lamp + 0.03380 x kWh in Sheet No. 10-4

B. Post-Top Lighting Service

	Tariff Code	**Watts**	**Rate**	
	111	100 (9,500 Lumens)	*$21.46*~~18.58~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
High Pressure Sodium	122	150 (16,000 Lumens)	*$33.75*~~29.23~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	120	250 (19,000 Lumens)	*$39.29*~~34.02~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	126	400 (40,000 Lumens)	*$51.57*~~44.66~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	Tariff Code	**Watts**	**Rate**	
Mercury Vapor	099	175 (7,000 Lumens)	*$17.31*~~14.99~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	Tariff Code	**Lumens**	**Rate**	
LED	160	6,000-10,000	*$24.90*~~21.56~~	per lamp + 0.03380 x kWh in Sheet No. 10-4

C. Flood Lighting Service

	Tariff Code	**Watts**	**Rate**	
High Pressure Sodium	107	200 (22,000 Lumens)	*$18.79*~~16.27~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	109	400 (50,000 Lumens)	*$27.44*~~23.76~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	Tariff Code	**Watts**	**Rate**	
Metal Halide	110	250 (20,500 Lumens)	*$22.80*~~19.74~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	116	400 (36,000 Lumens)	*$28.72*~~24.87~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	131	1,000 (110,000 Lumens)	*$52.28*~~45.27~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	130	250 Mongoose (20,500 Lumens)	*$29.74*~~25.75~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	136	400 Mongoose (36,000 Lumens)	*$36.30*~~31.43~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	Tariff Code	**Lumens**	**Rate**	
LED	165	17,500-22,500	*$32.33*~~28.00~~	per lamp + 0.03380 x kWh in Sheet No. 10-4
	166	42,500-47,500	*$39.73*~~34.40~~	per lamp + 0.03380 x kWh in Sheet No. 10-4

D. LED Lamp Conversion Charge

[…]

When new or additional facilities, other than those specified in Paragraphs A, B, and C, are to be installed by the Company, the customer in addition to the monthly charges, shall pay in advance the installation cost (labor and material) of such additional facilities extending from the nearest or most suitable pole of the Company to the point designated by the customer for the installation of said lamp, except that customer may, for the following facilities only, elect, in lieu of such payment of the installation cost to pay:

Wood Pole	*$4.70*~~4.08~~	per month
Overhead wire span not over 150 feet	*$2.25*~~2.26~~	per month
Underground wire lateral not over 50 feet (Price includes pole riser and connections)	*$7.65*~~7.66~~	per month

E. Flexible Lighting Option (Tariff Code 175 for Unmetered and Tariff Code 201 for Metered)

[…]

Rate
Customers shall pay the monthly lamp charge for the System, a monthly maintenance charge, a non-fuel energy charge, a base fuel charge, and all applicable adjustment clauses.

Monthly Lamp Charge* = IC x MLFCR

Where:
IC = Installed Cost of System
MLFCR = Monthly Levelized Fixed Cost Rate of ~~1.42~~*1.48*% which is inclusive of return, depreciation, income taxes, property taxes and A&G expense components

Monthly maintenance charge is *$2.53*~~0.80~~ per lamp per month
Monthly non-fuel charge is *0.08523*~~.08561~~$/kWh
Base fuel charge is 0.03380 $/kWh

Tariff S.L.
(Street Lighting)

Rate (Tariff Code 528)

A. Overhead Service on Existing Distribution Poles

	Watts	**Rate**	
High Pressure Sodium	100 (9,500 Lumens)	*$10.02*~~8.64~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	150 (16,000 Lumens)	*$11.00*~~9.49~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	200 (22,000 Lumens)	*$13.03*~~11.24~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	400 (50,000 Lumens)	*$17.11*~~14.76~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Lumens	**Rate**	
LED	8,000-11,000	*$11.47*~~9.89~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	10,000-14,000	*$14.72*~~12.70~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	24,000-30,000	*$17.55*~~15.14~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 6,000-10,000	*$11.91*~~10.27~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 8,000-12,000	*$26.41*~~22.78~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Flood 17,500-22,500	*$19.33*~~16.67~~	per lamp + 0.03380 x kWh in Sheet No. 11-3

B. Service on New Wood Distribution Poles

	Watts	**Rate**	
High Pressure Sodium	100 (9,500 Lumens)	*$15.66*~~13.51~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	150 (16,000 Lumens)	*$16.78*~~14.47~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	200 (22,000 Lumens)	*$18.82*~~16.23~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	400 (50,000 Lumens)	*$24.15*~~20.83~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Lumens	**Rate**	
LED	8,000-11,000	*$18.90*~~16.30~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	10,000-14,000	*$22.17*~~19.12~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	24,000-30,000	*$25.01*~~21.57~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 6,000-10,000	*$19.34*~~16.68~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 8,000-12,000	*$33.85*~~29.20~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Flood 17,500-22,500	*$26.78*~~23.10~~	per lamp + 0.03380 x kWh in Sheet No. 11-3

C. Service on New Metal or Concrete Poles*

	Watts	**Rate**	
High Pressure Sodium	100 (9,500 Lumens)	*$32.63*~~28.15~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	150 (16,000 Lumens)	*$33.82*~~29.17~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	200 (22,000 Lumens)	*$35.86*~~30.93~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	400 (50,000 Lumens)	*$39.94*~~34.45~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Lumens	**Rate**	
LED	8,000-11,000	*$33.03*~~28.49~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	10,000-14,000	*$35.24*~~30.40~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	24,000-30,000	*$36.98*~~31.90~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 6,000-10,000	*$34.01*~~29.34~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Post Top 8,000-12,000	*$48.34*~~41.70~~	per lamp + 0.03380 x kWh in Sheet No. 11-3
	Flood 17,500-22,500	*$38.71*~~33.39~~	per lamp + 0.03380 x kWh in Sheet No. 11-3

E. Flexible Lighting Option (Tariff Code 525 for Unmetered and Tariff Code 526 for Metered)

[…]

Rate
Customers shall pay the monthly lamp charge for the System, a monthly maintenance charge, a non-fuel energy charge, a base fuel charge, and all applicable adjustment clauses.

Monthly Lamp Charge* = IC x MLFCR

Where:
IC = Installed Cost of System
MLFCR = Monthly Levelized Fixed Cost Rate of *1.09*~~1.04~~% which is inclusive of return, depreciation, income taxes, property taxes and A&G expense components

CONTINUED

Monthly maintenance charge is $*2.50*~~2.52~~ per lamp per month
Monthly non-fuel charge is *0.06102*~~.05192~~ $/kWh
Base fuel charge is 0.03380 $/kWh

Tariff N.M.S. II
(Net Metering Service II)

Billing Charges

[…]

Bill credits to customers for NNE at the avoided cost rate each billing period is a purchased power expense and shall be recovered from all customers through the Company's Purchased Power Adjustment Rider. If the NNE credit exceeds the customer's billed energy charges, along with any riders that are based on a per kWh charge, during the billing period, the amount in excess will be carried over for use in subsequent billing periods. *Excess electricity credits are not transferable between customers or locations. When the customer elects to no longer take service under this Net Metering Service II Tariff, any unused credit shall revert to the Company.*

Tariff COGEN/SPP-II
(Cogeneration and/or Small Power Production--Over ~~100~~*45* KW)

Availability of Service
This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a net power production capacity of over ~~100~~*45* KW. In addition, cogeneration facilities must have a net power production capacity at or below 20,000 KW, and small power production facilities must have a net power production capacity at or below 5,000 KW. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

Monthly Charges for Delivery from the Company to the Customer
Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers *with cogeneration and/or small power production facilities having a total design capacity of more than 10 KW* shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.

Monthly Credits or Payments for Energy and Capacity Deliveries

[…]

Capacity Credit
If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used, *$4.53 kW/month, times the lowest of:*

~~A.~~	~~2023/2024~~	~~$3.48~~	~~kW/month~~
	~~2024/2025~~	~~$3.72~~	~~kW/month~~
	~~2025/2026~~	~~$3.25~~	~~kW/month, times the lowest of:~~

1. monthly contract capacity, or
2. current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730,or
3. lowest average capacity metered during the previous two months if less than monthly contract capacity.

If T.O.D. energy meters are used, *$10.88 kW/month, times the lowest of:*

~~B.~~	~~2023/2024~~	~~$8.36~~	~~kW/month~~
	~~2024/2025~~	~~$8.92~~	~~kW/month~~
	~~2025/2026~~	~~$7.79~~	~~kW/month, times the lowest of:~~

1. on-peak contract capacity, or
2. current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by 305, or
3. lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

Term of Contract
Contracts under this tariff shall be made for a term not less than five (5) years *and no longer than twenty (20) years.* A Qualifying Facility *("QF")* can request that avoided cost rates be set on an "as available" basis or when a legally enforceable obligation is established.

The Company shall not provide a prospective Cogen/SPP customer with a contract for service under this tariff until the customer has met the burden of establishing a legally enforceable obligation ("LEO") under PURPA. A LEO will be established for the Customer's facility when the following criteria have been met to the Company's satisfaction:

1. *Documentation of having obtained Qualifying Facility status from FERC pursuant to the certification procedures set out in 18 CFR 292.207. QFs that "self-certify" must provide the Company with its submitted FERC Form No. 556 – Certification of QF Status for Small Power Production and Cogeneration Facilities.*
2. *Documentation provided to the electric utility of all of the following: (i) a description of the location of the project and its proximity to other projects within one mile of the project and within 10 miles of the project, which are owned or controlled by the same developer, and (ii) an estimated, non-binding, good faith estimate of the energy production for the project that includes the kilowatt-hours or megawatt hours to be produced by the QF for each month and year of the entire term of the project's anticipated avoided cost power purchase agreement.*
3. *Documentation of an interconnection application with the appropriate electric utility, and proof of payment of applicable application fees.*
4. *Documentation of meaningful steps to obtain site control adequate to commence construction of the project at the proposed location.*
5. *Documentation of all applications, including filing fees, to obtain all necessary local permitting and zoning approvals.*
6. *If qualifying as a "cogeneration facility" as defined by 18 CFR 292.202(c), written proof, provided to the electric utility, of a steam host that is willing to contract for steam over the full term of the project's anticipated power purchase agreement for a cogeneration facility.*
7. *Proof of a deposit, paid in full, to cover the estimated costs for a system impact or facilities study, such as an engineering review or distribution study, should a study or studies become necessary.*

Tariff F.P.
(FlexPay Program)

Availability of Service
This tariff is available on a voluntary basis to all residential customers who have an Advanced Metering Infrastructure (AMI) meter installed at their residence, except as provided below.

This tariff is not available to residential customers taking metered service under Tariff R.S.D. or customers with medical, life threatening, or life support conditions; customers having on-site generation operated in parallel with the Company's system; or customers on the Average Monthly Payment (AMP) plan or Equal Payment Plan (Budget). It also is not available to customers without a valid and operable electronic communication method (i.e., text or electric mail). It also is not available to a customer scheduled for a disconnection of service for nonpayment who has initiated the process for enrollment in this tariff two or more times within a thirty (30) day period without completing all of the requirements for enrollment.

Program Description
Kentucky Power's FlexPay Program is a voluntary payment option that allows customers to prepay for, and pay as they use, electric service.

Terms and Conditions
1. *Service under FlexPay will be offered to a customer under the customer's otherwise applicable standard residential rate schedule. Billing will be based on the customer's daily usage, the effective base rate, the tax rate, and all applicable riders and fees. Fixed charges will be applied to the account on a daily basis based on 1/30 of the total fixed charges. These amounts will be subtracted from the customer's daily FlexPay account balance.*
2. *To enroll in FlexPay, a customer must make an initial payment of $40.00. Any deposit that an existing customer has previously paid to the Company will be applied to the customer's current account balance, with the remaining credit/debit balance transferred to the customer's prepay balance. A customer with an outstanding current balance or final account balance from a previous account may carry-over up to $500 of the account balance to the FlexPay Program. Any payments made to the account will first have a 20% portion of the payment applied to the arrears balance before it is credited to the customer's account until the past due balance is paid.*
3. *The customer is responsible for monitoring prepaid usage and ensuring that the account balance is sufficient to continue electric service. The customer will be notified when the account reaches the customer-selected balance threshold or the minimum threshold amount of $25.00. Notification will occur through the customer's preferred form of communication, including email, and/or text message. A customer web portal will be available to view the customer's usage information.*
4. *Should a customer's balance reach zero, the customer will be notified via the customer's chosen communication method. The customer will have until the beginning of the next business day to reestablish a positive balance or the customer's meter will automatically be disconnected during normal business hours. Normal business hours are 8:00 a.m. to 5:00 p.m., Monday through Thursday, and 8:00 a.m. to noon on Fridays, excluding Company-observed holidays and moratoriums. Customers will be required to adjust their payment to cover any accrued balance for usage during weekends, holidays and moratoriums. Once the customer's payment is received and accepted, service will be restored by the Company in a timely manner.*
5. *Financial assistance received for a FlexPay account will be credited to the balance of the FlexPay account upon receipt of the funds.*
6. *Customers presenting a Winter Hardship Reconnect, Certificate of Need, or Medical Certificate as provided in 807 KAR 5:006, Sections 14, 15, and 16 will be removed from FlexPay and placed on the tariff that is otherwise applicable to the customer's service.*
7. *No deposit, reconnect, or late fee charges shall apply to customers enrolled in FlexPay.*
8. *When the Company receives a dishonored negotiable instrument (i.e. returned check), any account credits associated with that instrument will be removed from the customer's account. If the removal of the credits results in the customer's balance reaching zero, the customer will be notified and will have until the beginning of the next business day to reestablish a positive balance or the customer's meter will automatically be disconnected during normal business hours.*
9. *Actual billing will continue to be based upon the applicable rate and meter readings obtained to determine consumption. FlexPay customers are required to participate in and receive their information through the Company's paperless billing program. Customers will continue to receive an online monthly statement summary containing all of the charges, usage, and payments applied during their normal 30-day billing cycle.*
10. *Customer accounts must be funded through a Company authorized payment channel, including immediate payment via telephone or website using electronic check, debit or credit cards, and any in-person pay station. Each authorized payment method is subject to Company guidelines. Timing of the payments to the accounts cannot be guaranteed if payment is made through an unauthorized pay agent or by mail.*
11. *The customer may cancel service under this tariff at any time and will be returned to the applicable traditional post-pay billing option in accordance with Kentucky Power's Commission approved tariffs.*
12. *Settlement occurs when participation in the plan is terminated. This happens if an account is final billed or if the customer requests termination. If the account finals off-cycle during the billing period, the remaining monthly fixed charges and fees that have not been collected will be applied to the final bill. After settlement of the FlexPay account, any remaining unused balance will be transferred to the customer's other active account(s). If the customer does not have any other active accounts the Company shall refund by one of the following means: a prepaid card, a check, or electric funds transfer (EFT).*

Tariff S.S.C.
(System Sales Clause)

Rate

[. . .]

3. The base annual net revenues from system sales are: $*4,425,300*~~1,935,350~~.

[. . .]

Tariff P.P.A.
(Purchase Power Adjustment)

Rate
The annual purchase power adjustment factor will be computed using the following formula:

1. Annual Purchase Power Net Costs (PPANC)

PPANC = N+CSIRP~~+RKP~~+RP+*GS*-BPP

Where:

BPP = The annual amount of purchase power costs included in base rates, $*7,988,625*~~6,554,678~~.

a. N = The annual cost of power purchased by the Company through new Purchase Power Agreements and purchased power expense from avoided cost payments to net metering customers under tariff N.M.S.II above or below the $*3,309,439*~~1,269,331~~ included in BPP. All new purchase power agreements shall be approved by the Commission to the extent required by KRS 278.300.
b. CSIRP = The net annual cost of any credits provided to customers under Tariff C.S.-I.R.P., Tariff D.R.S., ~~Tariff V.C.S.~~ and special contracts for interruptible service above or below the $*2,616,539*~~1,165,983~~ included in BPP.
~~c. RKP = Rockport related items includable in Tariff PPA pursuant to the Commission approved Settlement agreement in Case No. 2017-00179:~~
~~1. Rockport deferral amount to be recovered.~~
~~Pursuant to the January 19, 2024 and February 2, 2024 Orders of the Kentucky Public Service Commission in Case No. 2023-00159 collection of this regulatory asset under this rider is temporarily suspended pending the securitization of the regulatory asset. The Company will continue to accrue carrying charges on the regulatory asset at the Company's approved weighted average cost of capital until securitized bonds are issued. If Kentucky Power is unable to issue securitized bonds, collection of this regulatory asset under this rider will be reinstated;~~
~~2. Rockport offset estimate and true-up;~~
~~3. Final (over)/under recovery associated with tariff CC following its expiration.~~
~~d.~~*c.* RP = The cost of fuel related to substitute generation less the cost of fuel which would have been used in plants suffering forced generation or transmission outages above or below the $*190,571*~~4,119,364~~ included in BPP.
d. GS = Net gains or losses on incidental sales of gas above or below the $1,872,076 included in BPP.

Rates

[…]

The Purchase Power Adjustment factors shall be modified annually using the following formula:

~~The Purchase Power Adjustment factors shall be determined as follows~~:

For all tariff classes without demand billing:

kWh Factor = PPA(E) x (BE Class /BE Total) + PPA(D) x (CP Class /CP Total) / BE Class

kW Factor = 0

For all tariff classes with demand billing:

kWh Factor = PPA(E) x (BE Class /BE Total) / BE Class

kW Factor = PPA(D) x (CP Class /CP Total) / BD Class

Where:

1. "PPA(D)" is the actual annual retail PPA demand-related costs, plus any prior review period (over)/under recovery.

2. "PPA(E) is the actual annual retail PPA energy-related costs, plus any prior review period (over)/under recovery.

3. "BE Class" is the ~~historic~~ *forecasted* annual retail jurisdictional billing kWh for each tariff class for the current year.

4. "BD Class" is the ~~historic~~ *forecasted* annual retail jurisdictional billing kW for each applicable tariff class for the current year.

5. "CP Class" is the coincident peak demand for each tariff class estimated as follows:

Tariff Class	BEClass	CP/kWh Ratio	CPClass
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.		0.02227~~22970~~%	
S.G.S.-T.O.D.		0.01746~~18187~~%	
M.G.S.-T.O.D.		0.01746~~18187~~%	
G.S.		0.01746~~18187~~%	
L.G.S., L.G.S.-T.O.D.		0.01515~~16146~~%	
L.G.S.-L.M.-T.O.D.		0.01515~~16146~~%	
I.G.S. and C.S.-I.R.P.		0.01178~~11832~~%	
M.W.		0.01146~~12350~~%	
O.L.		0.00361~~5294~~%	
S.L.		0.00359~~5375~~%	

6. "BE Total" is the sum of the BE Class for all tariff classes.

7. "CP Total" is the sum of the CP Class for all tariff classes.

8. The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of *0.28*~~0.40~~% and the KPSC Maintenance Fee of 0.*15951*~~1493~~% and other similar revenue based taxes or assessments occasioned by the Purchase Power Adjustment Rider revenues.

Tariff G.R.
(Generation Rider)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S. – I.R.P., M.W., O.L. and S.L.

Rate
The annual Generation Rider factor will be computed using the following formula:

Non-Environmental Mitchell Annual Revenue Requirement (ARR) = (RB+CWIP)(ROR)+DE+PT+OU

Where:

RB = Non-Environmental Rate Base for Mitchell represented by the sum of plant in service less accumulated depreciation;

CWIP = Construction Work in Progress for Non-Environmental Mitchell Projects;

ROR = Rate of Return on Non-Environmental Mitchell Rate Base;

DE = Depreciation Expense;

PT = Property Taxes;

OU = Cumulative difference between revenues received and actual costs for the reporting period, representing the (over) or under recovery.

Rates

Tariff Class	*$/kWh*	*$/kW*
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.	*$0.00519*	*--*
S.G.S.-T.O.D.	*$0.00406*	*--*
M.G.S.-T.O.D.	*$0.00406*	*--*
G.S.	*$0.00406*	*--*
L.G.S., L.G.S.-T.O.D.	*--*	*$1.15*
L.G.S.-L.M.-T.O.D.	*$0.00352*	*--*
I.G.S. and C.S.-I.R.P.	*--*	*$1.63*
M.W.	*$0.00267*	*--*
O.L.	*$0.00084*	*--*
S.L.	*$0.00084*	*--*

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS, LGS-T.O.D, IGS, and CS-I.R.P. tariff classes.

CONTINUED

The Generation Rider factors shall be modified annually using the following formula:

For all tariff classes without demand billing:

kWh Factor = GR(E) x (BE Class /BE Total) + GR(D) x (CP Class /CP Total) / BE Class

kW Factor = 0

For all tariff classes with demand billing:

kWh Factor = GR(E) x (BE Class /BE Total) / BE Class

kW Factor = GR(D) x (CP Class /CP Total) / BD Class

Where:

1. *"GR(D)" is the actual annual retail GR demand-related costs.*
2. *"GR(E) is the actual annual retail GR energy-related costs.*
3. *"BE Class" is the forecasted annual retail jurisdictional billing kWh for each tariff class for the current year.*
4. *"BD Class" is the forecasted annual retail jurisdictional billing kW for each applicable tariff class for the current year.*
5. *"CP Class" is the coincident peak demand for each tariff class estimated as follows:*

Tariff Class	*BEClass*	*CP/kWh Ratio*	*CPClass*
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.		*0.022274%*	
S.G.S.-T.O.D.		*0.017461%*	
M.G.S.-T.O.D.		*0.017461%*	
G.S.		*0.017461%*	
L.G.S., L.G.S.-T.O.D.		*0.015157%*	
L.G.S.-L.M.-T.O.D.		*0.015157%*	
I.G.S. and C.S.-I.R.P.		*0.011787%*	
M.W.		*0.011468%*	
O.L.		*0.003614%*	
S.L.		*0.003595%*	

6. *"BE Total" is the sum of the BE Class for all tariff classes.*
7. *"CP Total" is the sum of the CP Class for all tariff classes.*
8. *The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.28% and the KPSC Maintenance Fee of 0.1595% and other similar revenue based taxes or assessments occasioned by the Generation Rider revenues.*
9. *The annual GR factors shall be filed with the Commission by February 15 of each year based on prior calendar year, with rates to begin with the April billing period, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.*
10. *Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.*

Tariff E.S.
(Environmental Surcharge)

Rate

[…]

The revenues to which the residential Environmental Surcharge factor are applied is the sum of the customer's Service Charge, Energy Charge(s), *Demand Charge (if applicable),* Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Residential Energy Assistance, ~~and~~ Purchase Power Adjustment*, and Generation Rider.*

The revenues to which the all other customer Environmental Surcharge factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Kentucky Economic Development Surcharge, ~~and~~ Purchase Power Adjustment*, and Generation Rider.*

1. Monthly Environmental Surcharge Gross Revenue Requirement, E(m)
Where: E(m) = CRR-BRR

CRR = Current Period Revenue Requirement for the Expense Month.

BRR = Base Period Revenue Requirement.

2. Base Period Revenue Requirement, BRR

BRR = The Following Monthly Amounts:

Billing Month		Base Net Environmental Costs
January	$	~~3,022,418~~*3,431,790*
February		~~2,558,332~~*3,493,649*
March		~~2,621,611~~*3,165,974*
April		~~2,519,828~~*3,567,100*
May		~~2,514,284~~*3,262,891*
June		~~2,644,974~~*2,825,006*
July		~~2,594,563~~*2,815,870*
August		~~2,741,097~~*2,808,114*
September		~~2,508,995~~*2,667,203*
October		~~2,376,639~~*3,372,548*
November		~~2,423,992~~*3,258,712*
December	$	~~2,597,739~~*3,306,420*
	$	~~31,124,472~~*37,975,278*

[…]

3. Current Period Revenue Requirement, CRR

[…]

The Environmental Compliance Rate Base for Kentucky Power reflects the current cost associated with the 1997 Plan, the 2003 Plan, the 2005 Plan, the 2007 Plan, the 2015 Plan, the 2017 Plan, the 2019 Plan, and the 2021 Plan. The Environmental Compliance Rate Base for Kentucky Power should also include construction work in progress until assets are placed in service and cash working capital allowance based on the net operations and maintenance expense lead days of ~~53.92~~*19.82* authorized in Case No. *2025-00257*~~2023-00159~~. The Operating Expenses for Kentucky Power reflects the current operating expenses associated with the 1997 Plan, the 2003 Plan, the 2005 Plan, the 2007 Plan, the 2015 Plan, the 2017 Plan, the 2019 Plan, and the 2021 Plan.

The Rate of Return for Kentucky Power is ~~9.65~~*10.0*% rate of return on equity as authorized by the Commission in its Order Dated ~~January 19, 2024~~*XXXX XX, XXXX*, Case No. *2025-00257*~~2023-00159~~.

[…]

6. Environmental costs "E" shall be the Company's costs of compliance with the Clean Air Act and those environmental requirements that apply to coal combustion wastes and by-products, as follows:

Total Company:
- return on Title IV and CSAPR SO2 allowance inventory
- over/under recovery balances between the actual costs incurred less the amount collected through the environmental surcharge
- costs associated with any Commission's consultant approved by the Commission
- costs associated with the consumption of Title IV and CSAPR SO2 allowances
- costs associated with the consumption of NOx allowances
- return on NOx allowance inventory
- costs associated with maintaining approved pollution control equipment including material and contract labor (excluding plant labor)
- costs associated with consumables used in conjunction with approved environmental projects.
- return on inventories of consumables used in conjunction with approved environmental projects.
- return on environmental compliance rate base including construction work in progress.
- *Monthly expense associated with ARO (Asset Retirement Obligations) depreciation and accretion.*
- ~~Monthly expense to amortize the $1,446,998.35 regulatory asset for prudently incurred ELG (Effluent Limitation Guidelines) project costs over a two-year period to begin with July 2022 billing and conclude with June 2024 billing.~~

Decommissioning Rider
(D.R.)

Rate

[…]

5. The Revenues to which the residential Decommissioning Rider factor are applied is the sum of the customer's Service Charge, Energy Charge(s), *Demand Charge (if applicable),* Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Residential Energy Assistance, ~~and~~ Purchase Power Adjustment*, and Generation Rider.*

The Revenues to which the all other customer Decommissioning Rider factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Kentucky Economic Development Surcharge, ~~and~~ Purchase Power Adjustment*, and Generation Rider.*

Securitized Surcharge Rider
(S.S.R.)

Rate

[…]

5. The Residential PBR Allocation (y) shall be recovered from residential customers through application of the Residential S.S.R. Adjustment Factor to all charges on each residential customers bill for electric service, except for environmental surcharge (ES) *and Decommissioning Rider (DR)* charges, nonrecurring charges, and pass through charges as discussed and defined in the financing order in Case No. 2023-00159. The charges to which the Residential S.S.R. Adjustment Factor currently applies, based on that definition, are the sum of the customer's Service Charge, Demand Charge, Energy Charge(s), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Residential Energy Assistance, ~~and~~ Purchase Power Adjustment*, and Generation Rider.*
6. The Non-Residential PBR Allocation (y) shall be recovered through application of the Non-Residential S.S.R. Adjustment Factor to all charges on each non-residential retail electric customers bill for electric service, except for charges for base fuel costs and fuel cost adjustments, and environmental surcharge (ES) *and Decommissioning Rider (DR)* charges, nonrecurring charges, and pass through charges as discussed and defined in the financing order in Case No. 2023-00159. The charges to which the Non-Residential S.S.R. Adjustment Factor currently applies, based on that definition, are the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Kentucky Economic Development Surcharge, ~~and~~ Purchase Power Adjustment*, and Generation Rider.*

Federal Tax Cut Tariff
(F.T.C.)

Rate

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2023-00159, Kentucky Power Company is to credit to retail ratepayers the approved annual amount of excess accumulated deferred federal income taxes (ADIT) beginning January 16, 2024.
2. The Company shall amortize the calendar year retail Generation and Distribution related Protected Excess ADIT of $*1,410,730*~~1,969,031~~ to support the rate credits provided to customers through this tariff.
3. ~~Subject to Commission approval of the Company's application for a financing order authorizing the Company to securitize the Rockport Deferral Regulatory Asset, Tariff P.P.A. Under-Recovery Regulatory Asset, and Storm Expense Deferral Regulatory Assets identified in the Company's Application in 2023-00159 (collectively, the "Non-Decommissioning Rider Regulatory Assets"), and subject to the Company's issuance of securitized bonds that include the Non-Decommissioning Rider Regulatory Assets, t~~The Company shall provide customers with the ADIT benefit related to Non-Decommissioning Rider Regulatory Assets *(defined as the Rockport Deferral Regulatory Asset, Tariff P.P.A. Under-Recovery Regulatory Asset, and Storm Expense Deferral Regulatory Assets)* approved for securitization through this tariff, at its Commission-approved WACC. The ADIT benefit described in this paragraph will be annually trued-up to address over/(under) recovery pursuant to the procedure described in paragraph ~~7~~*8* of this tariff.
4. *Upon receipt of a Private Letter Ruling from the IRS affirming the Company's analysis that excluding its NOLC adjustment from rates would constitute a normalization violation, recovery of the NOLC regulatory asset established in accordance with the Commission's January 19, 2024 Order in Case No. 2023-00159 over a three-year period starting XXXX XX, XXXX.*

EFFECT ON PROPOSED CHANGE IN CUSTOMER RATES

If approved as filed, the Company's proposed changes to its rates will result in a proposed annual increase in electric revenues for Kentucky Power of approximately 14.62%. Changes in associated rates for affected customer classes are listed in the tables below. Kentucky Power is also proposing changes in the text of some of its rate schedules and other tariff provisions, including its terms and conditions for electric service as detailed above.

The estimated amount of annual change for each electric customer class is as follows:

Electric Rate Class	Annual Average Usage (kWh)	Annual $ Increase	Annual % Increase
Residential Service			
Residential Service	14,502	$42,620,555	14.9%
Residential Load Management Time-of-Day	20,137	$50,796	12.4%
Residential Service Time-of-Day	24,717	$3,548	12.5%
Experimental Residential Service Time-of-Day	N/A	N/A	N/A
Residential Demand-Meter Electric Service	N/A	N/A	N/A
General Service			
General Service	20,430	$14,071,301	13.8%
Recreational Lighting Service	14,602	$31,424	13.8%
Load Management TOD	24,183	$31,610	13.3%
Unmetered Service	2,878	$64,676	11.4%
Small General Service TOD	14,971	$168,828	13.3%
Medium General Service TOD	51,068	$137,987	12.6%
Large General Service	840,827	$9,594,587	14.4%
L.G.S. Load Management TOD	175,791	$17,412	13.8%
Large General Service TOD	1,171,730	$118,781	10.2%
Industrial Service			
Industrial General Service	38,871,022	$27,281,453	15.0%
All Other			
Municipal Waterworks	228,962	$32,722	13.5%
Outdoor Lighting	670	$1,110,573	11.9%
Street Lighting	654	$225,075	11.8%
Pole Attachments	N/A	N/A	N/A
COGEN/SPP	N/A	N/A	N/A
NMS	N/A	N/A	N/A
NMS II - Residential	N/A	N/A	N/A
NMS II – Non-Residential	N/A	N/A	N/A

The average monthly usage and the amount of the proposed increase in the monthly bill for the average customer in each electric customer class is as follows:

Electric Rate Class	Monthly Average Usage (kWh)	Current Monthly Average Bill $	Proposed Monthly Average Bill $	Monthly $ Increase*	Monthly % Increase
Residential Service					
Residential Service	1,208	$183.37	$210.67	$27.30	14.9%
Residential Load Management Time-of-Day	1,678	$244.98	$275.43	$30.45	12.4%
Residential Service Time-of-Day	2,060	$296.69	$333.65	$36.96	12.5%
Experimental Residential Service Time-of-Day	N/A	N/A	N/A	N/A	N/A
Residential Demand-Meter Electric Service	N/A	N/A	N/A	N/A	N/A
General Service					
General Service	1,702	$291.90	$332.08	$40.17	13.8%
Recreational Lighting Service	1,217	$213.70	$243.12	$29.42	13.8%
Load Management TOD	2,015	$318.44	$360.92	$42.49	13.3%
Unmetered Service	240	$51.79	$57.72	$5.93	11.4%
Small General Service TOD	1,248	$216.73	$245.50	$28.77	13.3%
Medium General Service TOD	4,256	$640.79	$721.77	$80.98	12.6%
Large General Service	70,069	$10,089.50	$11,545.87	$1,456.37	14.4%
L.G.S. Load Management TOD	14,649	$2,107.29	$2,397.50	$290.20	13.8%
Large General Service TOD	97,644	$13,818.84	$15,232.90	$1,414.06	10.2%
Industrial Service					
Industrial General Service	3,239,252	$257,116.06	$295,649.19	$38,533.13	15.0%
All Other					
Municipal Waterworks	19,080	$2,529.29	$2,870.14	$340.85	13.5%
Outdoor Lighting	56	$16.88	$18.89	$2.01	11.9%
Street Lighting	54	$13.25	$14.81	$1.56	11.8%
Pole Attachments	N/A	N/A	N/A	N/A	N/A
COGEN/SPP	N/A	N/A	N/A	N/A	N/A
NMS	N/A	N/A	N/A	N/A	N/A
NMS II - Residential	N/A	N/A	N/A	N/A	N/A
NMS II – Non-Residential	N/A	N/A	N/A	N/A	N/A

* Monthly increase may not sum to the difference between Current Monthly Average Bill and Proposed Monthly Average Bill due to rounding.

Kentucky Power's application is available for examination, during normal business hours, at Kentucky Power's offices located at 1645 Winchester Avenue, Ashland, Kentucky 41101; 12333 Kevin Avenue, Ashland, Kentucky; 1400 E. Main Street, Hazard, Kentucky; and 3249 N. Mayo Trail, Pikeville, Kentucky; or by visiting the Company's website: www.kentuckypower.com.

The Company's application is also available for examination between the hours of 8:00 a.m. to 4:30 p.m., Monday through Friday, at the Public Service Commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky and may be found on the Commission's Web site at http://psc.ky.gov at Case No. 2025-00257.

Written comments on Kentucky Power's application and the proposed rates may be submitted to the Public Service Commission by mail to Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602-0615, or via the Commission's website: http://psc.ky.gov. All comments should reference Case No. 2025-00257.

The Company is not proposing to modify other rates and charges not included in this notice. The rates contained in this notice are the rates proposed by Kentucky Power. The Public Service Commission may order rates to be charged that differ from the proposed rates contained in this Notice. Such action by the Commission may result in rates for customers other than the rates contained in this notice.

Any person may submit a timely written request for intervention in Case No. 2025-00257. The motion shall be submitted to the Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602-0615, and shall establish the grounds for the request, including the status and interest of the party. If the Commission does not receive a written request for intervention within thirty (30) days of the initial publication of this Notice, the Commission may take final action on the application.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Certain Regulatory And Accounting Treatments; and (4) All Other Required Approvals And Relief	))))))	Case No. 2025-00257

Certification Of Compliance With Notice And Posting Requirements

Jeffrey D. Newcomb, Vice President, Regulatory and Finance for Kentucky Power Company ("Kentucky Power" or the "Company"), a utility furnishing retail electric service within the Commonwealth of Kentucky, certifies the following:

1. On August 29, 2025, Kentucky Power Company filed an Application with the Public Service Commission of Kentucky for approval of an adjustment of its electric rates, terms, and conditions of Kentucky Power Company, and seeking certain other relief.

2. In connection with its Application, Kentucky Power provided the following notices:

(a) Kentucky Power filed with the Commission on July 29, 2025, its Notice of Intent in accordance with the requirements of 807 KAR 5:001, Section 16(2). A copy of the Notice of Intent also was provided electronically to the Office of the Attorney General, Office of Rate Intervention in accordance with 807 KAR 5:001, Section 16(2)(c) on July 29, 2025. The Notice of Intent also was provided electronically to counsel for all other intervenors in Case No. 2023-00159.

(b) The customer notice required by 807 KAR 5:001, Section 17(2) and 807 KAR 5:011, Section 8(2) will be published once a week for three consecutive weeks in a prominent manner in newspapers of general circulation in Kentucky Power's service area ("Customer Notice"). The Customer Notice was first published beginning August 22, 2025. An affidavit verifying the contents of the published Customer Notice, that the notice was published, and the dates of publication will be filed in accordance with 807 KAR 5:001, Section 17(3)(b) and 807 KAR 5:011, Section 8(3)(b) within 45 days of the date the Application is submitted to the Commission.

(c) On or before August 29, 2025, Kentucky Power made the public posting of the Customer Notice required by 807 KAR 5:001, Section 17(1)(a) and 807 KAR 5:011, Section 8(1)(a) at each of the offices listed below. The Company also is providing a copy of the Application for public inspection at Kentucky Power's corporate offices and distribution operations centers at the following locations:

(i) Ashland Corporate Office, 1645 Winchester Avenue, Ashland, Kentucky;

(ii) Cannonsburg (Ashland) Service Center, 12333 Kevin Avenue, Ashland, Kentucky;

(iii) Hazard Service Center, 1400 E. Main Street, Hazard, Kentucky; and

(iv) Pikeville Service Center, 3249 N. Mayo Trail, Pikeville, Kentucky.

The public postings of the Customer Notice and copies of the Application will remain available for public inspection in conformity with the requirements of 807 KAR 5:001, Section 17(1)(c) and 807 KAR 5:011, Section 8(1)(c) until the Commission enters a final decision in this matter.

(d) On or before August 29, 2025, Kentucky Power posted on its website (kentuckypower.com) the information and hyperlink required by 807 KAR 5:001, Section

17(1)(b) and 807 KAR 5:011, Section 8(1)(b). This information will remain available for public access and inspection in conformity with the requirements of 807 KAR 5:001, Section 17(1)(c) and 807 KAR 5:011, Section 8(1)(c) on Kentucky Power's website until the Commission enters a final decision in this matter.

3. The customer notice and public posting described in paragraphs 2(b) and 2(c) of this certification conformed to and contained the information required by 807 KAR 5:001, Section 17(4) and 807 KAR 5:011, Section 8(4).

4. The Customer Notice identified in paragraph 2 above and attached hereto contains a clear and concise explanation of the proposed change in the rate schedule applicable to each customer class.

Given under my hand this 29th day of August, 2025.

Jeffrey D. Newcomb
Vice President, Regulatory and Finance
Kentucky Power Company
1645 Winchester Avenue
Ashland, KY 41101

Case No. 2025-00257

Notice of Election to Use Electronic Filing Procedures
Revised June 2014

NOTICE OF ELECTION OF USE OF ELECTRONIC FILING PROCEDURES

(Complete All Shaded Areas and Check Applicable Boxes)

In accordance with 807 KAR 5:001, Section 8, Kentucky Power Company gives notice of its intent to file an application for (see Attachment 1) with the Public Service Commission no later than August 29, 2025 and to use the electronic filing procedures set forth in that regulation.

Kentucky Power Company further states that:

		Yes	No
1.	It requests that the Public Service Commission assign a case number to the intended application and advise it of that number as soon as possible;	X	
2.	It or its authorized representatives have registered with the Public Service Commission and are authorized to make electronic filings with the Public Service Commission;	X	
3.	Neither it nor its authorized representatives have registered with the Public Service Commission for authorization to make electronic filings but will do so no later than seven days before the date of its filing of its application for rate adjustment;	n/a	
4.	It or its authorized agents possess the facilities to receive electronic transmissions;	X	
5.	The following persons are authorized to make filings on its behalf and to receive electronic service of Public Service Commission orders and any pleadings filed by any party or the Public Service Commission Staff:		

Name	Electronic Mail Address
Kentucky Power Company	kentucky_regulatory_services@aep.com
Hector Garcia Santana	hgarcia1@aep.com
Katie M. Glass	kglass@stites.com

See Attachment 2 for additional persons

6.	It and its authorized representatives listed above have read and understand the procedures for electronic filing set forth in 807 KAR 5:001 and will fully comply with those procedures unless the Public Service Commission directs otherwise.	X	

RECEIVED
JUL 29 2025
PUBLIC SERVICE COMMISSION

Signed */s/ Katie M. Glass*

Name: Katie M. Glass
Title: Counsel for Kentucky Power Company
Address: Stites & Harbison, PLLC, P.O. Box 634
Frankfort, KY 40602-0634
Telephone Number: 502-209-1212

Attachment 1

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Certain Regulatory And Accounting Treatments; and (4) All Other Required Approvals And Relief	))))))	Case No. 2025-00257

Attachment 2

Additional Persons Authorized To Make Filings Or Receive Electronic Service

Name	**E-Mail Address**
Michael J. Schuler	mjschuler@aep.com
Kenneth J. Gish	kgish@stites.com
Tanner S. Wolffram	tswolffram@aep.com
Harlee P. Havens	hhavens@stites.com
Jeffrey D. Newcomb	jnewcomb@aep.com
Jennifer L. Parrish	jlparrish@aep.com

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Certain Regulatory And Accounting Treatments; and (4) All Other Required Approvals And Relief	))))))	Case No. 2025-00257

NOTICE OF INTENT

Pursuant to 807 KAR 5:001, Section 16(2) and all other applicable statutory provisions and regulations, Kentucky Power Company gives notice of its intent to file on or before August 29, 2025, an application seeking: (1) a general adjustment of its electric rates; (2) approval of its tariffs and riders; (3) approval of certain regulatory and accounting treatments; and (4) all other required approvals and relief.

The general adjustment of Kentucky Power Company's rates for electric service will be supported by Kentucky Power Company's historical test year for the twelve months ended May 31, 2025.

Kentucky Power Company has transmitted a copy of this notice of intent in a portable document format by electronic mail to the Attorney General's Office of Rate Intervention at rateintervention@ag.ky.gov and to the other intervenors in the Company's last general rate case, Case No. 2023-000159:

Michael L. Kurtz
Jody Kyler Cohn
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
mkurtz@bkllawfirm.com
jkylercohn@bkllawfirm.com

John G. Horne
Lawrence W. Cook
Michael West
Angela Goad
Assistant Attorneys General
Office for Rate Intervention
700 Capital Avenue, Suite 20
Frankfort, KY 40601
John.Horne@ky.gov
Larry.Cook@ky.gov
Michael.West@ky.gov
Angela.goad@ky.gov

Byron Gary
Tom FitzGerald
Ashley Wilmes
Kentucky Resources Council
P.O. Box 1070
Frankfort, Kentucky 40602
Byron@kyrc.org
FitzKRC@aol.com
Ashley@kyrc.org

Kimberly S. McCann
W. Mitchell Hall, Jr.
VanAntwerp Attorneys, LLP
1544 Winchester Avenue, Fifth Floor
P.O. Box 1111
Ashland, KY 41105-1111
kmccann@vanattys.com
whall@vanattys.com

Carrie H. Grundmann
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, NC 27103
cgrundmann@spilmanlaw.com

Steven W. Lee
Spilman Thomas & Battle, PLLC
1100 Bent Creek Blvd., Suite 101
Mechanicsburg, PA 17050
slee@spilmanlaw.com

Megan W. Mullins
Spilman Thomas & Battle, PLLC
300 Kanawha Boulevard, East
P.O. Box 273
Charleston, WV 25321-0273
mmullins@spilmanlaw.com

Respectfully submitted,

Katie M. Glass
STITES & HARBISON PLLC
421 West Main Street
P. O. Box 634
Frankfort, Kentucky 40602-0634
Telephone: (502) 223-3477
Fax: (502) 560-5377
kglass@stites.com

Kenneth J. Gish, Jr.
Harlee P. Havens
STITES & HARBISON PLLC
250 West Main Street, Suite 2300
Lexington, Kentucky 40507-1758
Telephone: (859) 226-2300
Fax: (859) 253-9144
kgish@stites.com
hhavens@stites.com

COUNSEL FOR KENTUCKY POWER COMPANY

Michelle Caldwell

From: Glass, Katie <kglass@stites.com>
Sent: Tuesday, July 29, 2025 12:15 PM
To: rateintervention@ag.ky.gov; mkurtz@bkllawfirm.com; jkylercohn@bkllawfirm.com; John.Horne@ky.gov; Larry.Cook@ky.gov; Michael.West@ky.gov; angela.goad@ky.gov; Byron@kyrc.org; FitzKRC@aol.com; ashley@kyrc.org; kmccann@vanattys.com; whall@vanattys.com; cgrundmann@spilmanlaw.com; slee@spilmanlaw.com; mmullins@spilmanlaw.com
Cc: Gish, Kenneth; Havens, Harlee
Subject: FW: Kentucky Power Company's Notice of Election & Notice of Intent - Base Rate Case
Attachments: KPCO Notice of Election.pdf; KPCO Notice of Intent.pdf

Good afternoon,

Attached please find a copy of the Notice of Election and Notice of Intent that Kentucky Power filed with the Kentucky PSC today, which is being transmitted to you pursuant to 807 KAR 5:001, Section 16(2). An electronic case has not yet been set up, but should be shortly. Please let me know if you have any questions.

Thank you,
Katie

Katie M. Glass | STITES & HARBISON PLLC
Direct: 502-209-1212
Cell: 502-744-5377
Schedule Meeting

From: Glass, Katie
Sent: Tuesday, July 29, 2025 12:07 PM
To: PSC Executive Director <PSCED@ky.gov>
Cc: Gish, Kenneth <kgish@stites.com>; Havens, Harlee <hhavens@stites.com>
Subject: Kentucky Power Company's Notice of Election & Notice of Intent - Base Rate Case

Dear Ms. Bridwell,

Attached please find Kentucky Power Company’s Notice of Election to Use Electronic Filing Procedures and Notice of Intent filed pursuant to 807 KAR 5:001, Section 16(2). Please let me know if you need anything further from me.

Thank you,

Katie M. Glass
Member
Direct: 502-209-1212
Cell: 502-744-5377
Fax: 502-560-5377
kglass@stites.com

Schedule Meeting

STITES&HARBISON PLLC
250 West Main Street, Suite 2300, Lexington, KY 40507-1758
421 West Main Street, P.O. Box 634, Frankfort, KY 40602-0634

About Stites & Harbison

NOTICE OF ELECTION OF USE OF ELECTRONIC FILING PROCEDURES

(Complete All Shaded Areas and Check Applicable Boxes)

In accordance with 807 KAR 5:001, Section 8, Kentucky Power Company gives notice of its intent to file an application for (see Attachment 1) with the Public Service Commission no later than August 29, 2025 and to use the electronic filing procedures set forth in that regulation.

Kentucky Power Company further states that:

		Yes	No
1.	It requests that the Public Service Commission assign a case number to the intended application and advise it of that number as soon as possible;	X	
2.	It or its authorized representatives have registered with the Public Service Commission and are authorized to make electronic filings with the Public Service Commission;	X	
3.	Neither it nor its authorized representatives have registered with the Public Service Commission for authorization to make electronic filings but will do so no later than seven days before the date of its filing of its application for rate adjustment;	n/a	
4.	It or its authorized agents possess the facilities to receive electronic transmissions;	X	
5.	The following persons are authorized to make filings on its behalf and to receive electronic service of Public Service Commission orders and any pleadings filed by any party or the Public Service Commission Staff:		

Name	Electronic Mail Address
Kentucky Power Company	kentucky_regulatory_services@aep.com
Hector Garcia Santana	hgarcia1@aep.com
Katie M. Glass	kglass@stites.com

See Attachment 2 for additional persons

6.	It and its authorized representatives listed above have read and understand the procedures for electronic filing set forth in 807 KAR 5:001 and will fully comply with those procedures unless the Public Service Commission directs otherwise.	X	

Signed */s/ Katie M. Glass*

Name: Katie M. Glass

Title: Counsel for Kentucky Power Company

Address: Stites & Harbison, PLLC, P.O. Box 634

Frankfort, KY 40602-0634

Telephone Number: 502-209-1212

Attachment 1

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Certain Regulatory And Accounting Treatments; and (4) All Other Required Approvals And Relief	))))))	Case No. 2025-00____

Attachment 2

Additional Persons Authorized To Make Filings Or Receive Electronic Service

Name	**E-Mail Address**
Michael J. Schuler	mjschuler@aep.com
Kenneth J. Gish	kgish@stites.com
Tanner S. Wolffram	tswolffram@aep.com
Harlee P. Havens	hhavens@stites.com
Jeffrey D. Newcomb	jnewcomb@aep.com
Jennifer L. Parrish	jlparrish@aep.com

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Certain Regulatory And Accounting Treatments; and (4) All Other Required Approvals And Relief	))))))	Case No. 2025-00____

NOTICE OF INTENT

Pursuant to 807 KAR 5:001, Section 16(2) and all other applicable statutory provisions and regulations, Kentucky Power Company gives notice of its intent to file on or before August 29, 2025, an application seeking: (1) a general adjustment of its electric rates; (2) approval of its tariffs and riders; (3) approval of certain regulatory and accounting treatments; and (4) all other required approvals and relief.

The general adjustment of Kentucky Power Company's rates for electric service will be supported by Kentucky Power Company's historical test year for the twelve months ended May 31, 2025.

Kentucky Power Company has transmitted a copy of this notice of intent in a portable document format by electronic mail to the Attorney General's Office of Rate Intervention at rateintervention@ag.ky.gov and to the other intervenors in the Company's last general rate case, Case No. 2023-000159:

Michael L. Kurtz
Jody Kyler Cohn
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36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
mkurtz@bkllawfirm.com
jkylercohn@bkllawfirm.com

John G. Horne
Lawrence W. Cook
Michael West
Angela Goad
Assistant Attorneys General
Office for Rate Intervention
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Larry.Cook@ky.gov
Michael.West@ky.gov
Angela.goad@ky.gov

Byron Gary
Tom FitzGerald
Ashley Wilmes
Kentucky Resources Council
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Ashley@kyrc.org

Kimberly S. McCann
W. Mitchell Hall, Jr.
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Megan W. Mullins
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Respectfully submitted,

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Lexington, Kentucky 40507-1758
Telephone: (859) 226-2300
Fax: (859) 253-9144
kgish@stites.com
hhavens@stites.com

COUNSEL FOR KENTUCKY POWER COMPANY

Electric Rate Class	Year End Adjusted kWh	Year End Adjusted # of Customers	Annual Average Usage (kWh)	Monthly Average Usage (kWh)	Total kW	Annual Average Customer On Peak Demand (kW)	Monthly Average Customer On Peak Demand (kW)	Present Average Billing	Proposed Average Billing	Annual $ Increase	Annual % Increase	Monthly Bill $ Increase	Monthly Bill % Increase
Residential Service													
Residential Service	1,886,853,176	130,110	14,502	1,208				$ 183	$ 211	$42,620,555	14.9%	$27	14.9%
Residential Load Management Time-of-Day	2,799,027	139	20,137	1,678				$ 245	$ 275	$50,796	12.4%	$30	12.4%
Residential Service Time-of-Day	197,735	8	24,717	2,060				$ 297	$ 334	$3,548	12.5%	$37	12.5%
Experimental Residential Service Time-of-Day	NA	NA	NA	NA	NA	NA		NA	NA	NA	NA	NA	NA
Residential Demand-Meter Electric Service	NA	NA	NA	NA	NA	NA		NA	NA	NA	NA	NA	NA
General Service													
General Service	596,317,296	29,189	20,430	1,702	1,159,215	40	3	$ 292	$ 332	$14,071,301	13.8%	$40	13.8%
Recreational Lighting Service	1,299,575	89	14,602	1,217				$ 214	$ 243	$31,424	13.8%	$29	13.8%
Load Management TOD	1,499,357	62	24,183	2,015				$ 318	$ 361	$31,610	13.3%	$42	13.3%
Unmetered Service	2,616,378	909	2,878	240				$ 52	$ 58	$64,676	11.4%	$6	11.4%
Small General Service TOD	7,320,966	489	14,971	1,248				$ 217	$ 246	$168,828	13.3%	$29	13.3%
Medium General Service TOD	7,251,724	142	51,068	4,256				$ 641	$ 722	$137,987	12.6%	$81	12.6%
Large General Service	461,614,105	549	840,827	70,069	1,427,736	2,601	217	$ 10,090	$ 11,546	$9,594,587	14.4%	$1,456	14.4%
L.G.S. Load Management TOD	878,955	5	175,791	14,649				$ 2,107	$ 2,397	$17,412	13.8%	$290	13.8%
Large General Service TOD	8,202,111	7	1,171,730	97,644	15,279	2,183	182	$ 13,819	$ 15,233	$118,781	10.2%	$1,414	10.2%
Industrial Service													
Industrial General Service	2,293,390,283	59	38,871,022	3,239,252	3,700,646	62,723	5,227	$ 257,116	$ 295,649	$27,281,453	15.0%	$38,533	15.0%
All Other													
Municipal Waterworks	1,831,694	8	228,962	19,080				$ 2,529	$ 2,870	$32,722	13.5%	$341	13.5%
Outdoor Lighting	30,809,971	46,013	670	56				$ 17	$ 19	$1,110,573	11.9%	$2	11.9%
Street Lighting	7,836,986	11,985	654	54				$ 13	$ 15	$225,075	11.8%	$2	11.8%
Pole Attachments	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
COGEN/SPP I	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
COGEN/SPP II	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
NMS	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
NMS II - Residential	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
NMS II - Non-Residential	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total	5,310,719,340	161,765	32,830	5	6,302,876	67,546	5,629	$ 337	$ 386	$95,561,328	14.6%	$49	14.6%

KENTUCKY POWER BILLING ANALYSIS
TEST YEAR ENDED MAY 31, 2025
REVENUE SUMMARY SHEET

Tariff	Total TY Per Books Revenue	Book To Bill Adjustment	Less Fuel Adjustment Clause	Less HEAP and Economic Development	Less System Sales	Less Capacity Charge	Less Env. Surcharge	Less Purchase Power Adj	Less Decommissioning Rider	Less Fed Tax Cut
RS	$286,298,621		$17,008,167	$626,859	$838,670	$0	$10,963,550	$6,802,050	$0	($1,217,211)
RS LMTOD	$408,619		$25,238	$669	$1,265	$0	$15,686	$9,789	$0	($1,807)
RS TOD	$28,482		$1,780	$38	$84	$0	$1,074	$754	$0	($126)
Residential Total	$286,735,722		$17,035,186	$627,565	$840,019	$0	$10,980,310	$6,812,594	$0	($1,219,144)
GS-SEC	$100,980,320		$5,464,975	$350,328	$252,366	$0	$4,681,437	$1,858,270	$0	($261,043)
GS-NM	$564,920		$24,732	$10,975	$1,188	$0	$30,222	$8,245	$0	($1,187)
SGS TOD	$1,271,782		$68,400	$5,911	$3,159	$0	$58,566	$23,219	$0	($3,239)
GS-AF	$228,233		$12,254	$1,052	$604	$0	$10,385	$3,675	$0	($572)
GSLMTOD	$236,917		$13,284	$737	$670	$0	$11,154	$4,135	$0	($649)
MGSTOD	$1,091,908		$67,732	$1,696	$3,216	$0	$49,011	$22,052	$0	($3,226)
GS-PRI	$1,210,631		$74,903	$894	$3,646	$0	$54,558	$22,382	$0	($3,490)
GS-SUB	$53,066		$2,674	$48	$99	$0	$2,370	$994	$0	($115)
GS Total	$105,637,778		$5,728,952	$371,641	$264,947	$0	$4,897,702	$1,942,971	$0	($273,521)
LGS-SEC	$40,921,439		$2,690,064	$4,252	$123,176	$0	$1,763,947	$765,193	$0	($127,382)
LGSLMTOD	$126,438		$8,048	$60	$376	$0	$5,687	$2,563	$0	($391)
LGS-SEC TOD	$748,673		$54,633	$74	$2,489	$0	$30,764	$12,246	$0	($2,590)
LGS-PRI TOD	$412,110		$32,116	$24	$1,540	$0	$16,358	$5,670	$0	($1,523)
LGS-PRI	$11,820,552		$798,875	$720	$37,098	$0	$502,626	$268,668	$0	($37,872)
LGS-SUB	$723,415		$65,705	$86	$3,064	$0	$26,504	$16,355	$0	($3,118)
LGS-TRAN	$98,532		$9,657	$11	$480	$0	$4,493	$1,943	$0	($378)
LGS Total	$54,851,157		$3,659,099	$5,227	$168,223	$0	$2,350,380	$1,072,638	$0	($173,255)
PS-SEC	$12,637,734		$761,914	$1,537	$34,904	$0	$561,549	$271,014	$0	($35,486)
PS-PRI	$267,961		$19,133	$12	$884	$0	$11,346	$5,844	$0	($872)
PS Total	$12,905,695		$781,047	$1,549	$35,789	$0	$572,895	$276,858	$0	($36,359)
IGS-SEC	$2,261,433		$182,192	$60	$8,427	$0	$82,326	$48,900	$0	($8,593)
IGS-PRI	$27,421,840		$2,301,023	$408	$106,084	$0	$1,070,150	$719,465	$0	($108,720)
IGS-SUB	$131,625,485		$16,681,649	$220	$726,969	$0	$3,864,706	$3,822,579	$0	($750,051)
IGS-TRAN	$20,729,411		$2,649,850	$36	$122,292	$0	$625,601	$624,025	$0	($124,291)
IGS Total	$182,038,170		$21,814,714	$724	$963,772	$0	$5,642,783	$5,214,969	$0	($991,654)
OL	$9,318,114		$313,068	$0	$14,607	$0	$459,627	$31,179	$0	($14,195)
SL	$1,905,482		$76,194	$0	$3,621	$0	$95,423	$7,788	$0	($3,534)
MW	$242,812		$17,052	$96	$781	$0	$10,223	$4,045	$0	($787)
Total	$653,634,929	$0	$49,425,312	$1,006,802	$2,291,758	$0	$25,009,342	$15,363,042	$0	($2,712,449)

Income Statement	650,666,343.96	Total Firm Sales				
SSC deferral	4,727,891.17		Included in SSC Adjustment			
Rockport Reg Asset	(2,506,318.00)		Included in PPA adjustment			
Other manual adjustments	601,978.00					
Tariff Summary	653,489,895.13	Ties	$ -	$ 653,489,895	12 Mos May 2025 Tariff Summary	
Book to bill adj	145,034.33			$ 650,666,344	12 Mos May 2025 IS	
Billing analysis	653,634,929.46					

Test Year Base Rate Revenue	Environmental Surcharge Excluding FGD	Annualization/ Rate Change Revenue	Weather Normalization Revenue	Customer Annualization Revenue	Customer Specific Revenue	Adjusted Base Revenues	Proposed Base Revenue Increase	Proposed Base Revenue	CCOS Targets	Verification Difference	Rate Design Verification Difference
$251,276,536	$2,326,003	$17,931,312	($342,625)	($1,125,592)	$0	$270,065,634	$ 32,827,787	$ 302,893,421			
$357,777	$3,328	$24,413	($680)	($732)	$0	$384,107	$ 36,269	$ 420,376			
$24,879	$228	$1,873	($111)	$336	$0	$27,205	$2,522	$ 29,727			
$251,659,192	$2,329,559	$17,957,597	($343,415)	($1,125,987)	$0	$270,476,946	$32,866,578	$303,343,524	$303,342,973	($551)	($551)
$88,633,988	$993,204	$2,588,415	($417,579)	($236,296)	$0	$91,561,731	$ 11,515,591	$ 103,077,322			
$490,746	$6,412	$11,491	($247)	($11,450)	$0	$496,952	$ 54,053	$ 551,005			
$1,115,766	$12,425	$33,404	($5,232)	($8,437)	$0	$1,147,926	$ 139,104	$ 1,287,031			
$200,836	$2,203	$4,953	$0	$780	$0	$208,772	$ 26,148	$ 234,920			
$207,587	$2,366	$5,238	($875)	$7,991	$0	$222,307	$ 25,522	$ 247,829			
$951,427	$10,398	$30,122	($3,870)	$3,377	$0	$991,454	$ 108,545	$ 1,099,999			
$1,057,738	$11,575	$30,919	($2,325)	($81,242)	$0	$1,016,665	$ 133,518	$ 1,150,184			
$46,996	$503	$1,502	$0	($13,166)	$0	$35,835	$1,143	$ 36,978			
$92,705,085	$1,039,086	$2,706,043	($430,128)	($338,443)	$0	$95,681,642	$12,003,625	$107,685,267	$107,685,273	$6	$5
$35,702,188	$374,235	$1,315,382	($163,512)	($125,949)	$0	$37,102,345	$ 4,920,367	$ 42,022,713			
$110,095	$1,207	$4,046	($691)	$0	$0	$114,656	$ 14,318	$ 128,974			
$651,056	$6,527	$27,477	($3,498)	($130,126)	$0	$551,437	$ 66,542	$ 617,979			
$357,924	$3,471	$14,120	($549)	$0	$0	$374,965	$ 34,669	$ 409,634			
$10,250,436	$106,636	$382,655	($32,496)	($4,587)	($393,732)	$10,308,913	$ 1,396,646	$ 11,705,558			
$614,820	$5,623	$31,005	$0	($13,138)	$0	$638,310	$ 80,223	$ 718,533			
$82,326	$953	$2,138	$0	$69,700	$0	$155,118	$ 19,224	$ 174,341			
$47,768,846	$498,652	$1,776,823	($200,746)	($204,100)	($393,732)	$49,245,744	$6,531,989	$55,777,733	$55,863,752	$86,020	($126)
$11,042,303	$119,137	$353,096	($38,061)	($96,274)	$0	$11,380,201	$ 1,502,954	$ 12,883,155			
$231,613	$2,407	$7,764	($581)	$0	$0	$241,203	$33,277	$ 274,480			
$11,273,916	$121,544	$360,861	($38,642)	($96,274)	$0	$11,621,404	$1,536,230	$13,157,635	$13,071,489	($86,145)	
$1,948,121	$17,466	$87,972	$0	$0	$0	$2,053,559	$ 321,565	$ 2,375,124			
$23,333,430	$227,041	$1,067,375	$0	($25,269)	$0	$24,602,577	$ 3,432,221	$ 28,034,798			
$107,279,413	$819,928	$7,595,321	$0	($1,079,416)	($474,124)	$114,141,123	$ 14,829,166	$ 128,970,289			
$16,831,898	$132,726	$1,261,697	$0	$0	$0	$18,226,321	$2,420,476	$ 20,646,798			
$149,392,863	$1,197,161	$10,012,366	$0	($1,104,685)	($474,124)	$159,023,580	$21,003,429	$180,027,009	$180,027,107	$98	$97
$8,513,827	$97,514	$144,495	$0	($38,767)	$0	$8,717,069	$ 1,084,693	$ 9,801,762	$9,799,312	($2,450)	($2,455)
$1,725,991	$20,245	$34,818	$0	$0	$0	$1,781,053	$ 218,492	$ 1,999,546	$1,999,395	($151)	($151)
$211,402	$2,169	$8,094	$0	$0	$0	$221,665	$ 27,831	$ 249,496	$ 249,488	($8)	($9)
$563,251,122	$5,305,929	$33,001,097	($1,012,932)	($2,908,256)	($867,856)	$596,769,104	$ 75,272,868	$672,041,972	$ 672,038,790	$ (3,182)	$ (3,189)

Tie-Out	Proposed Generation Rider	Total Increase	Total Proposed
	$9,792,768	$ 42,620,555	$328,919,176
	$14,527	$ 50,796	$459,415
	$1,026	$ 3,548	$32,030
$0	$9,808,321	$ 42,674,900	$329,410,621
	$2,390,634	$13,906,225	$114,886,545
	$10,622	$64,676	$629,596
	$29,723	$168,828	$1,440,610
	$5,276	$31,424	$259,656
	$6,087	$31,610	$268,527
	$29,442	$137,987	$1,229,894
	$29,651	$163,170	$1,373,801
	$763	$1,906	$54,972
$1	$2,502,200	$14,505,824	$120,143,602
	$935,248	$5,855,615	$46,777,054
	$3,094	$17,412	$143,850
	$11,452	$77,994	$826,667
	$6,118	$40,787	$452,897
	$323,813	$1,720,458	$13,541,010
	$19,196	$99,419	$822,834
	$6,164	$25,388	$123,920
$86,146	$1,305,085	$7,837,074	$62,688,232
	$349,739	$1,852,693	$14,490,427
	$7,736	$41,013	$308,974
($86,145)	$357,475	$1,893,706	$14,799,401
	$77,159	$398,724	$2,660,157
	$998,575	$4,430,796	$31,852,636
	$4,433,211	$19,262,377	$150,887,863
	$769,080	$3,189,556	$23,918,967
$1	$6,278,025	$27,281,453	$209,319,623
$5	$25,880	$1,110,573	$10,428,687
$0	$6,583	$225,075	$2,130,557
$0	$4,891	$32,722	$275,534
$ 8	$20,288,460	$95,561,328	$749,196,257

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

RESIDENTIAL SERVICE (011, 012, 013, 014, 015, 017, 022, 062)
RS

									Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $0.00519	Proposed Rates	Proposed Revenue ($)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
Billed kWh	983,840,308	431,355,344	481,762,270	0.11284	0.12052	0.12785	224,596,793	(2,681,998)	(7,896,294.56)		1,886,379,630		17,929,278	(342,893)	(1,009,541.26)		241,173,636	9,792,768	-	
Block 1 kWh (Proposed)											813,786,921								0.15750	128,171,440
Block 2 kWh (Proposed)											1,073,066,255								0.12606	135,275,600
																			-	-
Book to Bill Adjustment	-	-	-																	
Storage Water Heating	264,863	72,297	128,248	0.08549	0.09317	0.09317	41,328	2,885	5,253.35		473,546		2,034	269	489		44,120		0.09317	44,120
																			-	-
Customer Charge	910,161	229,847	427,139	20.00	20.00	20.00	31,342,940		(5,741)		1,561,406		-		(114,820)		31,228,120		-	-
Tier I Customer Charge (Proposed)											1,314,461								26.00	34,175,986
Tier II Customer Charge (Proposed)											249,681								40.00	9,987,240
Employee Customer Charge	1,665	406	751	20.00	20.00	20.00	56,440		(86)		2,736		-		(1,720)		54,720			-
																	-			-
Unbilled Test Year Revenues							($4,760,965)										(4,760,965)			(4,760,965)
Fuel							17,008,167													
HEAP Charge							626,859													
System Sales Clause							838,670													
Capacity Charge							-													
Environmental Surcharge							10,963,550					2,326,003					2,326,003			
Purchased Power Adjustment							6,802,050													
Decommissioning Rider							-													
Economic Development Charge							-													
Fed Tax Cut							(1,217,211)													
Total							**$ 286,298,621**					**$ 2,326,003**	**$ 17,931,312**	**$ (342,625)**	**(1,125,592)**	-	**$ 270,065,634**			**$ 302,893,421**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

RESIDENTIAL LOAD MANAGEMENT TIME-OF-DAY SERVICE (028, 030, 032, 034)
RS LMTOD

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $0.00519	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
On-peak kWh	573,109	253,639	285,795	0.14873	0.15641	0.17335	174,453	(5,938)	(2,348)		1,104,256		18,407	(1,029)	(407.01)	-	191,423	14,527	0.19962	220,432
Off-peak kWh	782,050	442,621	468,875	0.08549	0.09317	0.09317	151,782	3,725	(2,500)		1,694,771		6,006	347	(232.90)	-	157,902		0.09317	157,902
Book to Bill Adjustment	-	-	-				-		-		-			-	-	-	-			-
							-		-		-			-	-	-	-			-
C&LM Credit	41,756	17,161	17,610	(0.00745)	(0.00745)	(0.00745)	(570)	(359.76)	(184)		75,984		-	3	1.37	-	(566)			-
							-		-		-			-	-	-	-			-
Customer Charge	973	244	456	23.00	23.00	23.00	38,456		(4)		1,668		-	-	(92.00)	-	38,364		29.00	48,372
Separate Meter Charge	56	14	26	4.30	4.30	4.30	413		(0)		96		-	-	(0.99)	-	412		4.45	426
							-		-		-		-	-	-	-	-			-
Unbilled Test Year Revenues							($6,756)										(6,756)			(6,756)
Fuel							25,238													
HEAP Charge							669													
System Sales Clause							1,265													
Capacity Charge							-													
Environmental Surcharge							15,686					3,328					3,328			
Purchased Power Adjustment							9,789													
Decommissioning Rider							-													
Economic Development Charge							-													
Fed Tax Cut							(1,807)													
Total							**$ 408,619**					**$ 3,328**	**$ 24,413**	**$ (680)**	**(732)**	**-**	**$ 384,107**			**$ 420,376**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

RESIDENTIAL TIME-OF-DAY SERVICE (036)
RS TOD

								Unit Adjustments				Base Revenues Adjustments								
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Proposed Generation Rider ($) $0.00519	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
On-peak kWh	45,401	16,636	20,560	0.14873	0.15641	0.17335	12,919	(485)	946		83,059		1,400	(76)	164.01	-	14,406	1,026	0.19962	16,580
Off-peak kWh	61,614	23,452	28,638	0.08549	0.09317	0.09317	10,121	(379)	1,352		114,676		473	(35)	125.94	-	10,684		0.09317	10,684
																				-
Customer Charge	54	14	26	23.00	23.00	23.00	2,162		2		96		-	-	46.00	-	2,208		29.00	2,784
																				-
Unbilled Test Year Revenues							($322)										(322)			(322)
Fuel							1,780													
HEAP Charge							38													
System Sales Clause							84													
Capacity Charge							-													
Environmental Surcharge							1,074					228					228			
Purchased Power Adjustment							754													
Decommissioning Rider							-													
Economic Development Charge							-													
Fed Tax Cut							(126)													
Total							**$ 28,482**					**$ 228**	**$ 1,873**	**$ (111)**	**336**	**-**	**$ 27,205**			**$ 29,727**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

SMALL GENERAL SERVICE EXPERIMENTAL TIME-OF-DAY (227)
SGS TOD

								Unit Adjustments				Base Revenues Adjustments							Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $0.00406	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
Summer On-Peak	502,093	-	10,020	0.19417	0.20185	0.20185	99,514	(17,318)	(4,341.65)		490,454		3,856	(3,496)	(876.36)	-	98,998	29,723	0.23244	114,001
Winter On-Peak	191,531	275,826	272,982	0.13693	0.14461	0.14461	105,590	4,702	(4,925)		740,116		1,471	680	(712.26)	-	107,028		0.22547	166,874
Off-Peak	3,655,817	844,768	1,651,655	0.12266	0.13034	0.13034	773,806	(18,540)	(43,304)		6,090,395		28,077	(2,417)	(5,644.30)	-	793,822		0.14004	852,899
																				-
Customer Charge	3,437	865	1,609	28.00	28.00	28.00	165,508		(43)		5,868		-	-	(1,204.00)	-	164,304		31.00	181,908
																				-
Unbilled Test Year Revenues							($28,651)										(28,651)			(28,651)
Fuel							68,400													
HEAP Charge							-													
System Sales Clause							3,159													
Capacity Charge							-													
Environmental Surcharge							58,566					12,425					12,425			
Purchased Power Adjustment							23,219													
Decommissioning Rider							-													
Economic Development Charge							5,911													
Fed Tax Cut							(3,239)													
Total							**$ 1,271,782**					**$ 12,425**	**$ 33,404**	**$ (5,232)**	**(8,437)**	**-**	**$ 1,147,926**			**$ 1,287,031**

KPSC Case No. 2025-00257
Application - Section II
Filing Requirements
Exhibit I
Page 7 of 34

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

GENERAL SERVICE - SECONDARY (211, 212, 215, 216, 218)
GS-SEC

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $0.00406	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
First 4,450 kWh	197,371,939	62,355,833	92,397,388	0.12292	0.13060	0.13060	44,471,729	(1,595,054)	(1,006,409.50)		349,523,697		1,515,816	(208,314)	(131,437.08)	-	45,647,795	2,390,634	0.14562	50,897,641
Over 4,450 kWh	139,661,218	44,029,791	57,726,055	0.10813	0.11581	0.11581	26,885,912	(1,619,527)	(495,195.44)		239,302,342		1,072,598	(187,557)	(57,348.58)	-	27,713,604		0.11853	28,364,507
																				-
Demand Charge	616,508	199,583	328,371	8.36	8.36	8.36	9,567,706	(2,597)	(2,548.12)		1,139,318		-	(21,708)	(21,302.31)	-	9,524,696		13.24	15,084,566
																				-
Customer Charge	203,616	51,243	95,469	28.00	28.00	28.00	9,809,184		(936)		349,392		-	-	(26,208.00)	-	9,782,976		31.00	10,831,152
																				-
Unbilled Test Year Revenues							($2,100,543)										(2,100,543)			(2,100,543)
Fuel							5,464,975													
HEAP Charge							-													
System Sales Clause							252,366													
Capacity Charge							-													
Environmental Surcharge							4,681,437					993,204					993,204			
Purchased Power Adjustment							1,858,270													
Decommissioning Rider							-													
Economic Development Charge							350,328													
Fed Tax Cut							(261,043)													
Total							**$ 100,980,320**					**$ 993,204**	**$ 2,588,415**	**$ (417,579)**	**(236,296)**	-	**$ 91,561,731**			**$ 103,077,322**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

GENERAL SERVICE - ATHLETIC FIELDS (214)
GS-AF

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $0.00406	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
All kWh	644,932	228,068	424,206	0.13247	0.14015	0.14015	176,850		2,368.31		1,299,575		4,953	-	331.92	-	182,135	5,276	0.15950	207,282
													-							-
Customer Charge	610	152	290	28.00	28.00	28.00	29,456		16		1,068		-	-	448.00	-	29,904		31.00	33,108
																				-
Unbilled Test Year Revenues							($5,470)										(5,470)			(5,470)
Fuel							12,254													
HEAP Charge							-													
System Sales Clause							604													
Capacity Charge							-													
Environmental Surcharge							10,385					2,203					2,203			
Purchased Power Adjustment							3,675													
Decommissioning Rider							-													
Economic Development Charge							1,052													
Fed Tax Cut							(572)													
Total							**$ 228,233**					**$ 2,203**	**$ 4,953**	**$ -**	**780**	**-**	**$ 208,772**			**$ 234,920**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

GENERAL SERVICE - NON METERED (204, 213)
GS-NM

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $0.00406	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
First 4,450 kWh	1,474,937	467,051	684,167	0.12292	0.13060	0.13060	331,648	(1,892)	(60,641.81)		2,563,621		11,328	(247)	(7,919.82)	-	334,809	10,622	0.14562	373,315
Over 4,450 kWh	21,286	53,279	-	0.10813	0.11581	0.11581	8,472	-	(21,808.19)		52,756		163	-	(2,525.61)	-	6,110		0.11853	6,253
Customer Charge	6,362	1,624	2,989	15.00	15.00	15.00	164,625		(67)		10,908		-	-	(1,005.00)	-	163,620		17.00	185,436
Unbilled Test Year Revenues							($13,999)										(13,999)			(13,999)
Fuel							24,732													
HEAP Charge							-													
System Sales Clause							1,188													
Capacity Charge							-													
Environmental Surcharge							30,222					6,412					6,412			
Purchased Power Adjustment							8,245													
Decommissioning Rider							-													
Economic Development Charge							10,975													
Fed Tax Cut							(1,187)													
Total							**$ 564,920**					**$ 6,412**	**$ 11,491**	**$ (247)**	**(11,450)**	**-**	**$ 496,952**			**$ 551,005**

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KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

GENERAL SERVICE LOAD MANAGEMENT TIME-OF-DAY (223,225)
GSLMTOD

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $0.00406	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
On-peak kWh	296,521	149,210	166,730	0.18443	0.19211	0.19211	115,382	(2,981)	24,346		633,825		2,277	(573)	4,677.11	-	121,764	6,087	0.22953	145,482
Off-peak kWh	385,496	222,244	227,413	0.08501	0.09269	0.09269	74,450	(3,264)	33,643		865,532		2,961	(303)	3,118.37	-	80,226		0.09493	82,165
																				-
Customer Charge	426	108	203	28.00	28.00	28.00	20,636		7		744		-	-	196.00	-	20,832		31.00	23,064
																				-
Unbilled Test Year Revenues							($2,882)										(2,882)			(2,882)
Fuel							13,284													
HEAP Charge							-													
System Sales Clause							670													
Capacity Charge							-													
Environmental Surcharge							11,154					2,366					2,366			
Purchased Power Adjustment							4,135													
Decommissioning Rider							-													
Economic Development Charge							737													
Fed Tax Cut							(649)													
Total							**$ 236,917**					**$ 2,366**	**$ 5,238**	**$ (875)**	**7,991**	**-**	**$ 222,307**			**$ 247,829**

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KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

MEDIUM GENERAL SERVICE TIME-OF-DAY (229)
MGSTOD

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $0.00406	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
On-peak kWh	1,500,189	546,444	729,738	0.18443	0.19211	0.19211	521,847	(11,745)	9,305.22		2,773,932		11,521	(2,256)	1,787.63	-	532,900	29,442	0.22953	636,701
Off-peak kWh	2,421,885	897,503	1,161,081	0.08501	0.09269	0.09269	396,695	(17,410)	14,732.99		4,477,792		18,600	(1,614)	1,365.60	-	415,047		0.09493	425,077
																				-
Customer Charge	980	249	466	28.00	28.00	28.00	47,488		8		1,704		-	-	224.00	-	47,712		31.00	52,824
																				-
Unbilled Test Year Revenues							($14,603)										(14,603)			(14,603)
Fuel							67,732													
HEAP Charge							-													
System Sales Clause							3,216													
Capacity Charge							-													
Environmental Surcharge							49,011					10,398					10,398			
Purchased Power Adjustment							22,052													
Decommissioning Rider							-													
Economic Development Charge							1,696													
Fed Tax Cut							(3,226)													
Total							**$ 1,091,908**					**$ 10,398**	**$ 30,122**	**$ (3,870)**	**3,377**	**-**	**$ 991,454**			**$ 1,099,999**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

GENERAL SERVICE - PRIMARY (217,220)
GS-PRI

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $0.00406	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
First 4,450 kWh	1,419,584	389,782	670,121	0.10790	0.11558	0.11558	275,677	(7,328)	(127,157.25)		2,345,002		10,902	(847)	(14,696.84)	-	271,035	29,651	0.12887	302,200
Over 4,450 kWh	2,606,362	1,424,332	1,393,459	0.09533	0.10301	0.10301	538,725	(12,901)	(452,938.78)		4,958,313		20,017	(1,329)	(46,657.22)	-	510,756		0.10543	522,755
																				-
Demand Charge	10,720	4,319	6,581	7.56	7.56	7.56	163,447	(20)	(1,774)		19,827		-	(149)	(13,408.25)	-	149,890		11.85	235,019
																				-
Customer Charge	525	134	235	120.00	120.00	120.00	107,280		(54)		840		-	-	(6,480.00)	-	100,800		140.00	117,600
																				-
Unbilled Test Year Revenues							($27,391)										(27,391)			(27,391)
Fuel							74,903													
HEAP Charge							-													
System Sales Clause							3,646													
Capacity Charge							-													
Environmental Surcharge							54,558					11,575					11,575			
Purchased Power Adjustment							22,382													
Decommissioning Rider							-													
Economic Development Charge							894													
Fed Tax Cut							(3,490)													
Total							**$ 1,210,631**					**$ 11,575**	**$ 30,919**	**$ (2,325)**	**(81,242)**	**-**	**$ 1,016,665**			**$ 1,150,184**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

GENERAL SERVICE - SUBTRAN 236
GS-SUB

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $0.00406	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
First 4,450 kWh	96,965	18,002	27,421	0.09763	0.10531	0.10531	14,250	-	(41,272)		101,116		745	-	(4,346.34)	-	10,649	763	0.11742	11,873
Over 4,450 kWh	98,583	7,978	13,502	0.08629	0.09397	0.09397	10,525	-	(33,236)		86,827		757	-	(3,123.15)	-	8,159		0.09618	8,351
																				-
Demand Charge	93	7	1	5.84	5.84	5.84	591		(30)		71		-	-	(176.23)	-	415		9.07	644
																				-
Customer Charge	29	7	12	460.00	460.00	460.00	22,080		(12)		36		-	-	(5,520.00)	-	16,560		460.00	16,560
																				-
Unbilled Test Year Revenues							($450)										(450)			(450)
Fuel							2,674													
HEAP Charge							-													
System Sales Clause							99													
Capacity Charge							-													
Environmental Surcharge							2,370					503					503			
Purchased Power Adjustment							994													
Decommissioning Rider							-													
Economic Development Charge							48													
Fed Tax Cut							(115)													
Total							**$ 53,066**					**$ 503**	**$ 1,502**	**$ -**	**(13,166)**	-	**$ 35,835**			**$ 36,978**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

LARGE GENERAL SERVICE - SECONDARY (240, 242, 260)
LGS-SEC

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $1.15	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
Billing kWh	171,273,754	45,032,170	74,925,308	0.08198	0.08966	0.08966	24,796,410	(1,367,695)	(1,293,103.74)		288,570,433		1,315,382	(122,628)	(115,939.68)	-	25,873,225	935,248	0.10238	29,543,841
Billing kW	471,970	123,510	221,551	13.84	13.84	13.84	11,307,707	(2,912)	(860)		813,259		-	(40,299)	(11,906.54)	-	11,255,502		15.76	12,820,017
Excess kVA	25,334	5,318	11,869	3.46	3.46	3.46	147,124	(169)	661		43,013		-	(586)	2,285.42	-	148,823		3.46	148,823
Customer Charge	2,467	623	1,162	97.00	97.00	97.00	412,444		(4)		4,248		-	-	(388.00)	-	412,056		111.00	471,528
Unbilled Test Year Revenues							($961,497)										(961,497)			(961,497)
Fuel							2,690,064													
HEAP Charge							-													
System Sales Clause							123,176													
Capacity Charge							-													
Environmental Surcharge							1,763,947					374,235					374,235			
Purchased Power Adjustment							765,193													
Decommissioning Rider							-													
Economic Development Charge							4,252													
Fed Tax Cut							(127,382)													
Total							**$ 40,921,439**					**$ 374,235**	**$ 1,315,382**	**$ (163,512)**	**(125,949)**	**-**	**$ 37,102,345**			**$ 42,022,713**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

LARGE GENERAL SERVICE - PRIMARY (244, 246)
LGS-PRI

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $1.15	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
Billing kWh	49,824,826	13,693,289	22,866,815	0.07352	0.08120	0.08120	6,631,802	(264,888)	(14,233)	(3,251,500)	82,854,309		382,655	(21,509)	(1,155.73)	(264,021.80)	6,727,770	323,813	0.09339	7,737,764
																				-
Billing kW	168,501	43,785	79,380	12.23000	12.23000	12.23000	3,567,073	(818)	(217)	(9,053.67)	281,576		-	(10,010)	(2,656.61)	(110,726.38)	3,443,680		13.93	3,922,352
																				-
Excess kVA	37,120	5,774	15,987	3.46000	3.46000	3.46000	203,731	(282.37)	(182)	(4,523)	53,895		-	(977)	(629.40)	(15,648.68)	186,476		3.46	186,476
																				-
Customer Charge	427	101	192	145.00	145.00	145.00	104,400		(1)	(23)	696		-	-	(145.00)	(3,335.00)	100,920		166.00	115,536
																				-
EDR Credit							-										-			-
																				-
																				-
																				-
																				-
																				-
																				-
																				-
																				-
Unbilled Test Year Revenues							($256,570)										(256,570)			(256,570)
Fuel							798,875													
HEAP Charge							-													
System Sales Clause							37,098													
Capacity Charge							-													
Environmental Surcharge							502,626					106,636					106,636			
Purchased Power Adjustment							268,668													
Decommissioning Rider							-													
Economic Development Charge							720													
Fed Tax Cut							(37,872)													
Total							**$ 11,820,552**					**$ 106,636**	**$ 382,655**	**$ (32,496)**	**(4,587)**	**(393,732)**	**$ 10,308,913**			**$ 11,705,558**

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KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

LARGE GENERAL SERVICE LOAD MANAGEMENT TIME-OF-DAY (251)
LGSLMTOD

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $0.00352	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
On-peak kWh	216,494	70,494	83,844	0.15932	0.16700	0.16700	60,266	(2,222)	-		368,610		1,663	(371)	-	-	61,558	3,094	0.20310	74,865
Off-peak kWh	310,290	98,154	105,304	0.08639	0.09407	0.09407	45,945	(3,403)	-		510,345		2,383	(320)	-	-	48,008		0.09677	49,386
																				-
Customer Charge	35	9	16	97.00	97.00	97.00	5,820		-		60		-	-	-	-	5,820		111.00	6,660
																				-
Unbilled Test Year Revenues							($1,937)										(1,937)			(1,937)
Fuel							8,048													
HEAP Charge							-													
System Sales Clause							376													
Capacity Charge							-													
Environmental Surcharge							5,687					1,207					1,207			
Purchased Power Adjustment							2,563													
Decommissioning Rider							-													
Economic Development Charge							60													
Fed Tax Cut							(391)													
Total							**$ 126,438**					**$ 1,207**	**$ 4,046**	**$ (691)**	**-**	**-**	**$ 114,656**			**$ 128,974**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

LARGE GENERAL SERVICE - TIME OF DAY - PRIMARY (257)
LGS-PRI TOD

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $1.15	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
On-peak kWh	760,419	229,778	427,701	0.12052	0.12820	0.12820	175,934	(1,830)	-		1,416,068		5,840	(235)	-	-	181,540	6,118	0.14084	199,439
Off-peak kWh	1,078,097	321,807	596,848	0.05966	0.06734	0.06734	126,182	(2,719)	-		1,994,033		8,280	(183)	-	-	134,278		0.06958	138,745
																				-
Billing kW	2,877	876	1,576	7.91000	7.91000	7.91000	42,151	(9)	-		5,320		-	(67)	-	-	42,084		10.78	57,353
																				-
Excess kVA	2,594	653	1,037	3.46	3.46	3.46	14,821	(19)	-		4,265		-	(64)	-	-	14,757		$3.46	14,757
																				-
Customer Charge	14	4	7	145	145	145	3,480		-		24		-	-	-	-	3,480		166.00	3,984
																				-
Unbilled Test Year Revenues							($4,645)										(4,645)			(4,645)
Fuel							32,116													
HEAP Charge							-													
System Sales Clause							1,540													
Capacity Charge							-													
Environmental Surcharge							16,358					3,471					3,471			
Purchased Power Adjustment							5,670													
Decommissioning Rider							-													
Economic Development Charge							24													
Fed Tax Cut							(1,523)													
Total							**$ 412,110**					**$ 3,471**	**$ 14,120**	**$ (549)**	-	-	**$ 374,965**			**$ 409,634**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

LARGE GENERAL SERVICE - SUBTRANSMISSION (248, 268)
LGS-SUB

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $1.15	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
Billing kWh	4,037,131	1,126,359	2,000,804	0.05524	0.06292	0.06292	419,772		(229,984.36)		6,934,309		31,005	-	(14,470.62)	-	436,307	19,196	0.07127	494,208
Billing kW	9,465	2,327	4,949	8.46000	8.46000	8.46000	141,631		(49)		16,692		-	-	(416.63)	-	141,215		9.64	160,844
Excess kVA	1,481	239	590	3.46000	3.46000	3.46000	7,991		939		3,249		-	-	3,249.24	-	11,240		3.46	11,240
Customer Charge	49	12	25	750.00	750.00	750.00	64,500		(2)		84		-	-	(1,500.00)	-	63,000		849.00	71,316
Unbilled Test Year Revenues							($19,075)										(19,075)			(19,075)
Fuel							65,705													
HEAP Charge							-													
System Sales Clause							3,064													
Capacity Charge							-													
Environmental Surcharge							26,504					5,623					5,623			
Purchased Power Adjustment							16,355													
Decommissioning Rider							-													
Economic Development Charge							86													
Fed Tax Cut							(3,118)													
Total							**$ 723,415**					**$ 5,623**	**$ 31,005**	**$ -**	**(13,138)**	**-**	**$ 638,310**			**$ 718,533**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

LARGE GENERAL SERVICE - TRANSMISSION (250, 270)
LGS-TRAN

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $1.15	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
Billing kWh	278,419	215,236	311,345	0.05430	0.06198	0.06198	47,756	-	631,000		1,436,000		2,138	-	39,109.38	-	89,003	6,164.48	0.07008	100,635
Billing kW	968	741	1,406	8.28	8.28	8.28	25,794		2,245		5,360		-	-	18,590.33	-	44,384		9.43	50,554
Excess kVA	-	-	-	3.46000	3.46000	3.46000	-		-		-		-	-	-	-	-		3.46	-
Customer Charge	3	2	3	750.00	750.00	750.00	6,000		16		24		-	-	12,000.00	-	18,000		849.00	20,376
Unbilled Test Year Revenues							$2,777										2,777			2,777
Fuel							9,657													
HEAP Charge							-													
System Sales Clause							480													
Capacity Charge							-													
Environmental Surcharge							4,493					953					953			
Purchased Power Adjustment							1,943													
Decommissioning Rider							-													
Economic Development Charge							11													
Fed Tax Cut							(378)													
Total							**$ 98,532**					**$ 953**	**$ 2,138**	**$ -**	**69,700**	**-**	**$ 155,118**			**$ 174,341**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

LARGE GENERAL SERVICE - TIME OF DAY - SECONDARY (256)
LGS-SEC TOD

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $1.15	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
On-peak kWh	1,551,009	358,920	636,960	0.12648	0.13416	0.13416	329,779	(13,695)	(479,546.22)		2,053,648		11,912	(1,837)	(64,335.92)	-	275,517	11,452	0.14753	302,975
Off-peak kWh	2,026,774	498,948	874,413	0.06138	0.06906	0.06906	219,248	(17,921)	(643,852.08)		2,738,362		15,566	(1,238)	(44,464.42)	-	189,111		0.07170	196,341
																				-
Billing kW	7,257	1,748	3,112	9.33000	9.33000	9.33000	113,052	(46.87)	(2,112)		9,958		-	(437)	(19,704.13)	-	92,910		13.10	130,453
																				-
Excess kVA	147	1	-	3.46	3.46	3.46	512	4	(76)		76		-	15	(263.49)	-	263		3.46	263
																				-
Customer Charge	48	10	16	97	97	97	7,178		(14)		60		-	-	(1,358.00)	-	5,820		111.00	6,660
																				-
Unbilled Test Year Revenues							($18,712)										(18,712)			(18,712)
Fuel							54,633													
HEAP Charge							-													
System Sales Clause							2,489													
Capacity Charge							-													
Environmental Surcharge							30,764					6,527					6,527			
Purchased Power Adjustment							12,246													
Decommissioning Rider							-													
Economic Development Charge							74													
Fed Tax Cut							(2,590)													
Total							**$ 748,673**					**$ 6,527**	**$ 27,477**	**$ (3,498)**	**(130,126)**	**-**	**$ 551,437**			**$ 617,979**

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KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

PUBLIC SCHOOL - SECONDARY (260)
PS-SEC

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $1.15	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
Billing kWh	45,976,067	13,753,009	21,092,808	0.08198	0.08966	0.08966	6,893,394	(303,761)	(667,569)		79,850,554		353,096	(27,235)	(59,854.23)	-	7,159,401	349,739	0.10238	8,175,100
																				-
Billing kW	175,995	47,007	84,407	13.84000	13.84000	13.84000	4,254,543	(765)	(2,524)		304,121		-	(10,583)	(34,926.43)	-	4,209,034		15.76	4,794,090
																				-
Excess kVA	4,676	546	1,426	3.46000	3.46000	3.46000	23,001	(70.12)	(67)		6,510		-	(243)	(232.73)	-	22,525		3.46	22,525
																				-
Customer Charge	897	224	416	97.00	97.00	97.00	149,089		(13)		1,524		-	-	(1,261.00)	-	147,828		111.00	169,164
																				-
Unbilled Test Year Revenues							($277,725)										(277,725)			(277,725)
Fuel							761,914													
HEAP Charge							-													
System Sales Clause							34,904													
Capacity Charge							-													
Environmental Surcharge							561,549					119,137					119,137			
Purchased Power Adjustment							271,014													
Decommissioning Rider							-													
Economic Development Charge							1,537													
Fed Tax Cut							(35,486)													
Total							**$ 12,637,734**					**$ 119,137**	**$ 353,096**	**$ (38,061)**	**(96,274)**	**-**	**$ 11,380,201**			**$ 12,883,155**

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PER BOOKS
TEST YEAR ENDED MAY 31, 2025

PUBLIC SCHOOL - PRIMARY (264)
PS-PRI

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $1.15	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
Billing kWh	1,010,990	424,468	538,541	0.07352	0.08120	0.08120	152,524	(5,501)	-		1,968,499		7,764	(447)	-	-	159,842	7,736	0.09339	183,838
Billing kW	3,641	1,174	1,921	12.23000	12.23000	12.23000	82,394	(10)	-		6,727		-	(122)	-	-	82,271		13.93	93,707
Excess kVA	106	-	-	3.46000	3.46000	3.46000	367	(3.63)	-		102		-	(13)	-	-	354		3.46	354
Customer Charge	7	2	3	145.00	145.00	145.00	1,740		-		12		-	-	-	-	1,740		166.00	1,992
Unbilled Test Year Revenues							($5,411)										(5,411)			(5,411)
Fuel							19,133													
HEAP Charge							-													
System Sales Clause							884													
Capacity Charge							-													
Environmental Surcharge							11,346					2,407					2,407			
Purchased Power Adjustment							5,844													
Decommissioning Rider							-													
Economic Development Charge							12													
Fed Tax Cut							(872)													
Total							**$ 267,961**					**$ 2,407**	**$ 7,764**	**$ (581)**	**$ -**	**$ -**	**$ 241,203**			**$ 274,480**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

INDUSTRIAL GENERAL SERVICE - SECONDARY (356)
IGS-SEC

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $1.63	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
Billing kWh	11,454,643	3,133,104	5,012,094	0.03156	0.03924	0.03924	681,126				19,599,840		87,972	-	-	-	769,098	77,159	0.04537	889,245
Billing kW							-													-
On-Peak	16,642	5,187	8,985	26.99	26.99	26.99	831,670				30,814		-	-	-	-	831,670		30.52	940,443
Off-Peak	15,954	5,094	8,836	1.84	1.84	1.84	54,987				29,884		-	-	-	-	54,987		2.08	62,159
Minimum	11,548	1,747	3,228	25.68	25.68	25.68	424,311				16,523		-	-	-	-	424,311		31.91	527,249
																				-
Billing kVAR	41	15	105	0.69	0.69	0.69	111				161		-	-	-	-	111		0.69	111
																				-
Customer Charge	35	9	16	276.00	276.00	276.00	16,560				60		-	-	-	-	16,560		276.00	16,560
																				-
Unbilled Test Year Revenues							($60,643)										(60,643)			(60,643)
Fuel							182,192													
HEAP Charge							-													
System Sales Clause							8,427													
Capacity Charge							-													
Environmental Surcharge							82,326					17,466					17,466			
Purchased Power Adjustment							48,900													
Decommissioning Rider							-													
Economic Development Charge							60													
Fed Tax Cut							(8,593)													
Total							**$ 2,261,433**					**$ 17,466**	**$ 87,972**	**$ -**	**-**	**-**	**$ 2,053,559**			**$ 2,375,124**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

INDUSTRIAL GENERAL SERVICE - PRIMARY (330, 358, 370)
IGS-PRI

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $1.63	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
Billing kWh	138,981,161	34,833,015	63,298,160	0.03007	0.03775	0.03775	7,883,615		(400,896)		236,711,440		1,067,375	-	(15,134)	-	8,935,857	998,575	0.04331	10,251,972
Billing kW																				-
On-Peak	321,372	74,867	153,117	24.94	24.94	24.94	13,700,944		(383)		548,973		-	-	(9,562)	-	13,691,382		28.33	15,552,400
Off-Peak	254,923	59,179	122,087	1.78	1.78	1.78	776,415		(404)		435,784		-	-	(720)	-	775,696		2.01	875,926
Minimum	38,923	13,107	11,620	23.68	23.68	23.68	1,507,225		-		63,650		-	-	-	-	1,507,225		29.68	1,889,123
																				-
Billing kVAR	79,946	18,147	34,587	0.69	0.69	0.69	91,549		212		132,892		-	-	146	-	91,695		0.69	91,695
																				-
Customer Charge	237	60	111	276.00	276.00	276.00	112,608		-		408		-	-	-	-	112,608		276.00	112,608
																				-
CS-IRP Demand Credit	32,459	10,654	11,458	(3.68)	(3.68)	(3.68)	(200,821)		-		54,571		-	-	-	-	(200,821)		(3.68)	(200,821)
																				-
EDR Credit							(56,125)										(56,125)			(56,125)
																				-
																				-
																				-
																				-
Unbilled Test Year Revenues							($481,980)										(481,980)			(481,980)
Fuel							2,301,023													
HEAP Charge							-													
System Sales Clause							106,084													
Capacity Charge							-													
Environmental Surcharge							1,070,150					227,041					227,041			
Purchased Power Adjustment							719,465													
Decommissioning Rider							-													
Economic Development Charge							408													
Fed Tax Cut							(108,720)													
Total							**$ 27,421,840**					**$ 227,041**	**$ 1,067,375**	**$ -**	**(25,269)**	**-**	**$ 24,602,577**			**$ 28,034,798**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

INDUSTRIAL GENERAL SERVICE - SUBTRANSMISSION (331, 333, 359, 371)
IGS-SUB

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $1.63	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
Billing kWh	988,974,141	246,098,569	440,184,930	0.02964	0.03732	0.03732	54,925,294	-	(15,016,238)	(5,325,400)	1,654,916,002		7,595,321	-	(560,406.00)	(198,743.93)	61,761,465	4,433,211	0.04269	70,648,364
Billing kW																				-
On-Peak	1,603,409	390,794	704,401	17.36	17.36	17.36	46,847,767		(26,863)	(13,545)	2,658,196		-	-	(466,341.69)	(235,141.20)	46,146,284		19.55	51,967,733
Off-Peak	1,527,784	377,163	678,551	1.75	1.75	1.75	4,521,123		(25,343)	(8,674)	2,549,482		-	-	(44,350.58)	(15,179.50)	4,461,593		1.98	5,047,974
Minimum	31,658	18,727	11,197	16.12	16.12	16.12	992,719		(2)	(16)	61,565		-	-	(29.78)	(257.92)	992,431		20.88	1,285,482
																				-
Billing kVAR	129,123	5,776	13,420	0.69	0.69	0.69	102,340		(3,956)	(11,779)	132,583		-	-	(2,729.70)	(8,127.65)	91,482		0.69	91,482
																				-
Customer Charge	138	36	58	794.00	794.00	794.00	184,208		(7)	(21)	204		-	-	(5,558.00)	(16,674.00)	161,976		794.00	161,976
																				-
CS-IRP Demand Credit	51,884	12,952	18,888	(3.68)	(3.68)	(3.68)	(308,104)		-		83,724		-	-	-	-	(308,104)		(3.68)	(308,104)
																				-
Special Contract Billing	61,851,871	15,441,371	33,058,759				4,438,288				110,352,001						4,438,288			4,499,603
																				-
EDR Credit							(2,009,983)										(2,009,983)			(2,009,983)
																				-
DRS Credit	187,919	93,862	79,747	(5.50)	(5.50)	(5.50)	(1,988,404)										(1,988,404)			(1,988,404)
																				-
Unbilled Test Year Revenues							($425,834)										(425,834)			(425,834)
Fuel							16,681,649													
HEAP Charge							-													
System Sales Clause							726,969													
Capacity Charge							-													
Environmental Surcharge							3,864,706					819,928					819,928			
Purchased Power Adjustment							3,822,579													
Decommissioning Rider							-													
Economic Development Charge							220													
Fed Tax Cut							(750,051)													
Total							**$ 131,625,485**					**$ 819,928**	**$ 7,595,321**	**$ -**	**(1,079,416)**	**(474,124)**	**$ 114,141,123**			**$ 128,970,289**

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INDUSTRIAL GENERAL SERVICE - TRANSMISSION (332, 360, 372)
IGS-TRAN

								Unit Adjustments				Base Revenues Adjustments						Proposed		
Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Units	Enviro Sur Excl FGD	Rate Annualization	Weather Normalization	Customer Annualization	Customer Pro Forma	Adjusted Base Revenue ($)	Generation Rider ($) $1.63	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
Billing kWh	164,283,516	38,516,311	69,011,172	0.02927	0.03695	0.03695	8,781,719				271,811,000		1,261,697	-	-	-	10,043,416	769,080	0.04216	11,459,552
Billing kW																				-
On-Peak	276,010	65,675	120,978	17.00	17.00	17.00	7,865,272				462,663		-	-	-	-	7,865,272		19.16	8,864,624
Off-Peak	245,323	60,185	106,366	1.73	1.73	1.73	712,542				411,874		-	-	-	-	712,542		1.96	807,274
Minimum	-	3,790	5,375	15.77	15.77	15.77	144,532				9,165		-	-	-	-	144,532		20.46	187,516
																				-
Billing kVAR	38,772	9,601	19,534	0.69	0.69	0.69	46,856				67,907		-	-	-	-	46,856		0.69	46,856
																				-
Customer Charge	21	5	10	1,353.00	1,353.00	1,353.00	48,708				36		-	-	-	-	48,708		1,353.00	48,708
																				-
CS-IRP Demand Credit	17,654	6,316	8,424	(3.68)	(3.68)	(3.68)	(119,210)				32,394		-	-	-	-	(119,210)		(3.68)	(119,210)
EDR Credit																				-
																				-
																				-
																				-
																				-
																				-
Unbilled Test Year Revenues							($648,522)										(648,522)			(648,522)
Fuel							2,649,850													
HEAP Charge							-													
System Sales Clause							122,292													
Capacity Charge							-													
Environmental Surcharge							625,601					132,726					132,726			
Purchased Power Adjustment							624,025													
Decommissioning Rider							-													
Economic Development Charge							36													
Fed Tax Cut							(124,291)													
Total							**$ 20,729,411**					**$ 132,726**	**$ 1,261,697**	**$ -**	**-**	**-**	**$ 18,226,321**			**$ 20,646,798**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

MUNICIPAL WATERWORKS (540)
MW

Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Unit Adjustments: Weather Normalization	Unit Adjustments: Customer Annualization	Unit Adjustments: Customer Pro Forma	Adjusted Units	Base Revenues Adjustments: Enviro Sur Excl FGD	Base Revenues Adjustments: Rate Annualization	Base Revenues Adjustments: Weather Normalization	Base Revenues Adjustments: Customer Annualization	Base Revenues Adjustments: Customer Pro Forma	Adjusted Base Revenue ($)	Proposed Generation Rider ($) $0.00267	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
All kWh	1,053,892	306,048	471,754	0.11073	0.11841	0.11841	208,797				1,831,694		8,094	-	-	-	216,891	4,891	0.13979	256,053
Minimum kW (kVA)	-	-	-	9.55	9.55	9.55	9,228				-			-	-	-	9,228		10.22	-
Customer Charge	56	14	26	25.00	25.00	25.00	2,400				96		-	-	-	-	2,400		28.00	2,688
Unbilled Test Year Revenues							($9,244)										(9,244)			(9,244)
Fuel							17,052													
HEAP Charge							-													
System Sales Clause							781													
Capacity Charge							-													
DSM Surcharge							221													
Environmental Surcharge							10,223					2,169					2,169			
Purchased Power Adjustment							4,045													
Decommissioning Rider							-													
Economic Development Charge							96													
Fed Tax Cut							(787)													
Total							**$ 242,812**					**$ 2,169**	**$ 8,094**	**$ -**	**-**	**-**	**$ 221,444**			**$ 249,496**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

OUTDOOR LIGHTING (093, 094, 095, 097, 098, 099, 103, 107, 109, 110, 111, 113, 116, 120, 122, 126, 131, 136, 150, 151, 152, 153, 160, 165, 166, 175, 201)
OL

	Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Energy per Lamp	Annual Energy	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Unit Adjustments: Weather Normalization	Unit Adjustments: Customer Annualization	Unit Adjustments: Customer Pro Forma	Adjusted Units	Adjusted Energy	Base Revenues Adjustments: Enviro Sur Excl FGD	Base Revenues Adjustments: Rate Annualization	Base Revenues Adjustments: Weather Normalization	Base Revenues Adjustments: Customer Annualization	Base Revenues Adjustments: Customer Pro Forma	Adjusted Base Revenue ($)	Proposed Generation Rider ($) $0.00084	Proposed Rates	Proposed Revenue
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)			
	Overhead Lighting Service																					25,880		-
	High Pressure Sodium																							-
094	KPKY - 094 OL 100 HP			142,842	484	5,761,294	10.25	10.25	10.25	1,464,131	-	(626)		142,216	5,736,029		-	-	(6,421)	-	1,457,710		11.84	1,683,833
113	KPKY - 113 OL 150 HP			127,442	704	7,476,597	11.69	11.69	11.69	1,489,797	-	(599)		126,883	7,443,811		-	-	(6,533)	-	1,483,264		13.50	1,712,922
097	KPKY - 097 OL 200 HP			15,785	1,012	1,331,202	14.14	14.17	14.17	223,673	-	(69)		15,716	1,325,364		-	-	(981)	-	222,693		16.36	257,110
098	KPKY - 098 OL 400 HP			2,664	2,000	444,000	22.38	22.38	22.38	59,620	-	(12)		2,652	442,053		-	-	(261)	-	59,359		25.84	68,536
103	KPKY - 103 OL 250 HP			36	1,236	3,708	20.19	20.19	20.19	727	-	(0)		36	3,692		-	-	(3)	-	724		23.32	836
	Mercury Vapor											-		-	-		-							
093	KPKY - 093 OL 175 MV			4,247	864	305,784	13.07	13.07	13.07	55,508	-	(19)		4,228	304,443		-	-	(243)	-	55,265		15.09	63,806
095	KPKY - 095 OL 400 MV			739	1,896	116,762	22.49	22.49	22.49	16,620	-	(3)		736	116,250		-	-	(73)	-	16,547		25.97	19,108
																	-		-					-
	Post Top Lighting Service																-							-
	High Pressure Sodium													-	-		-							-
111	KPKY - 111 OL100 HPP			7,976	484	321,699	18.58	18.58	18.58	148,194	-	(35)		7,941	320,288		-	-	(650)	-	147,544		21.46	170,414
122	KPKY - 122 OL150 HPP			746	704	43,765	29.23	29.23	29.23	21,806	-	(3)		743	43,573		-	-	(96)	-	21,710		33.75	25,067
120	KPKY - 120 OL 250HPP			12	1,236	1,236	34.02	34.02	34.02	408	-	(0)		12	1,231		-	-	(2)	-	406		39.29	469
126	KPKY - 126 OL 400HPP			14	2,000	2,333	44.66	44.66	44.66	625	-	(0)		14	2,323		-	-	(3)	-	622		51.57	719
																	-							
	Mercury Vapor																-							
099	KPKY - 099 OL175 MVP			60	864	4,320	14.99	14.99	14.99	899	-	(0)		60	4,301		-	-	(4)	-	895		17.31	1,034
																	-							
	Flood Lighting Service																-							
	High Pressure Sodium																-							-
107	KPKY - 107 OL 200HPF			16,914	1,012	1,426,414	16.27	16.27	16.27	275,191	-	(74)		16,840	1,420,159		-	-	(1,207)	-	273,984		18.79	316,420
109	KPKY - 109 OL400 HPF			39,044	2,000	6,507,333	23.76	23.76	23.76	927,685	-	(171)		38,873	6,478,797		-	-	(4,068)	-	923,617		27.44	1,066,669
																	-							-
	Metal Halide																-							-
110	KPKY - 110 OL 250 MH			1,274	1,204	127,825	19.74	19.74	19.74	25,149	-	(6)		1,268	127,264		-	-	(110)	-	25,038	$	22.80	28,920
116	KPKY - 116 OL 400 MH			8,487	1,896	1,340,946	24.87	24.87	24.87	211,072	-	(37)		8,450	1,335,066		-	-	(926)	-	210,146	$	28.72	242,678
130	KPKY - 130 OL 250MON			269	1,204	26,990	25.75	25.75	25.75	6,927	-	(1)		268	26,871		-	-	(30)	-	6,896	$	29.74	7,965
131	KPKY - 131 OL 1000MH			701	4,540	265,212	45.27	45.27	45.27	31,734	-	(3)		698	264,049		-	-	(139)	-	31,595	$	52.28	36,488
136	KPKY - 136 OL 400MON			36	1,896	5,688	31.43	31.43	31.43	1,131	-	(0)		36	5,663		-	-	(5)	-	1,127	$	36.30	1,301
																	-							
	LED																-							
150	6000-10000 Lumens			275,490	189	4,349,752	7.49	7.49	7.49	2,063,420		(1,208)		274,282	4,330,678		-		(9,049)		2,054,372	$	8.65	2,372,539
160	6000-10000 Lumens			695	317	18,360	21.56	21.56	21.56	14,984		(3)		692	18,279		-		(66)		14,918	$	24.90	17,230
165	17500-22500 Lumens			12,126	716	723,518	28.00	28.00	28.00	339,528		(53)		12,073	720,345		-		(1,489)		338,039	$	32.33	390,314
166	42500-47500 Lumens			2,808	1,457	340,938	34.40	34.40	34.40	96,595		(12)		2,796	339,443		-		(424)		96,172	$	39.73	111,073
	201 Flex																							
																								-
	Facilities Charge																							-
	Pole - total TY			48,472			4.08	4.08	4.08	197,766	-	(213)		48,259				-	(867)	-	196,899	$	4.70	226,819
	Span - total TY			51,799			2.26	2.26	2.26	117,066	-	(227)		51,572				-	(513)	-	116,552	$	2.25	116,037
	Lateral - total TY			525			7.66	7.66	7.66	4,022	-	(2)		523				-	(18)	-	4,004	$	7.65	3,999
																								-
	Unbilled Test Year Revenues									(229,730)											(229,730)			(229,730)
	Base Fuel	18,814,447	5,533,788	8,011,918		30,945,675	0.02612	0.03380	0.03380	949,278		(135,704)			30,809,971		144,495		(4,587)		1,089,186			1,089,186
	Fuel									313,068														
	HEAP Charge									-														
	System Sales Clause									14,607														
	Capacity Charge									-														
	Environmental Surcharge									459,627						97,514					97,514			
	Purchased Power Adjustment									31,179														
	Decommissioning Rider									-														
	Economic Development Charge									-														
	Fed Tax Cut									(14,195)														
	Total									**$ 9,318,114**						**$ 97,514**	**$ 144,495**	**$ -**	**$ (38,767)**	**$ -**	**$ 8,717,069**			**$ 9,801,762**

KENTUCKY POWER BILLING ANALYSIS
PER BOOKS
TEST YEAR ENDED MAY 31, 2025

STREET LIGHTING (528)
SL

Description	Units (Thru 12/30/24)	Units (Effec. 12/31/24)	Units (Effec. 2/21/25)	Rate thru 12/30/24	Rates Effec. 12/31/24	Rate as of 2/21/25	Per Books Revenue ($)	Unit Adjustments: Weather Normalization	Unit Adjustments: Customer Annualization	Unit Adjustments: Customer Pro Forma	Adjusted Units	Base Revenues Adjustments: Enviro Sur Excl FGD	Base Revenues Adjustments: Rate Annualization	Base Revenues Adjustments: Weather Normalization	Base Revenues Adjustments: Customer Annualization	Base Revenues Adjustments: Customer Pro Forma	Adjusted Base Revenue ($)	Proposed Generation Rider ($) $0.00084	Proposed Rates	Proposed Revenue
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)			
																		6,583		
OH Service on Distribution Poles																				
100 watts, 9,500 Lumens			76,407	8.64	8.64	8.64	660,156	-	-		76,407			-	-	-	660,156		10.02	765,598
150 watts, 16,000 Lumens			1,107	9.49	9.49	9.49	10,505	-	-		1,107			-	-	-	10,505		11.00	12,177
200 watts, 22,000 Lumens			3,541	11.24	11.24	11.24	39,801	-	-		3,541			-	-	-	39,801		13.03	46,139
400 watts, 50,000 Lumens			5,331	14.76	14.76	14.76	78,686	-	-		5,331			-	-	-	78,686		17.11	91,213
LED - 8,000-11,000 Lumens			39,740	9.89	9.89	9.89	393,029		-		39,740				-		393,029		11.47	455,818
LED - 10,000-14,000 Lumens			1,532	12.70	12.70	12.70	19,456		-		1,532				-		19,456		14.72	22,551
LED - 24,000-30,000 Lumens			1,294	15.14	15.14	15.14	19,591		-		1,294				-		19,591		17.55	22,710
Post Top 6,000-10,000 Lumens			1,188	10.27	10.27	10.27	12,201		-		1,188				-		12,201		11.91	14,149
Post Top 8,000-12,000 Lumens			12	22.78	22.78	22.78	273		-		12				-		273		26.41	317
Flood 17,500-22,500 Lumens			24	16.67	16.67	16.67	400		-		24				-		400		19.33	464
Service on New Wood Distribution Poles																				
100 watts, 9,500 Lumens			5,025	13.51	13.51	13.51	67,888	-	-		5,025			-	-	-	67,888		15.66	78,692
150 watts, 16,000 Lumens			267	14.47	14.47	14.47	3,863	-	-		267			-	-	-	3,863		16.78	4,480
200 watts, 22,000 Lumens			6,833	16.23	16.23	16.23	110,900	-	-		6,833			-	-	-	110,900		18.82	128,597
400 watts, 50,000 Lumens			480	20.83	20.83	20.83	9,998	-	-		480			-	-	-	9,998		24.15	11,592
LED - 8,000-11,000 Lumens			214	16.30	16.30	16.30	3,488		-		214				-		3,488		18.90	4,045
LED - 10,000-14,000 Lumens			-	19.12	19.12	19.12	-				-				-		-			-
LED - 24,000-30,000 Lumens			24	21.57	21.57	21.57	518				24				-		518		25.01	600
Post Top 6,000-10,000 Lumens			-	16.68	16.68	16.68	-				-				-		-			-
Post Top 8,000-12,000 Lumens			-	29.20	29.20	29.20	-				-				-		-			-
Flood 17,500-22,500 Lumens			-	23.10	23.10	23.10	-				-				-		-			-
Service on New Metal or Concrete Poles																				-
100 watts, 9,500 Lumens			-	28.15	28.15	28.15	-	-	-		-			-	-	-	-		32.63	-
150 watts, 16,000 Lumens			-	29.17	29.17	29.17	-	-	-		-			-	-	-	-		33.82	-
200 watts, 22,000 Lumens			1,080	30.93	30.93	30.93	33,404	-	-		1,080			-	-	-	33,404		35.86	38,729
400 watts, 50,000 Lumens			893	34.45	34.45	34.45	30,764	-	-		893			-	-	-	30,764		39.94	35,666
LED - 8,000-11,000 Lumens			-	28.49	28.49	28.49	-		-		-				-		-			-
LED - 10,000-14,000 Lumens			-	30.40	30.40	30.40	-		-		-				-		-		35.24	-
LED - 24,000-30,000 Lumens			24	31.90	31.90	31.90	766		-		24				-		766		36.98	888
Post Top 6,000-10,000 Lumens			-	29.34	29.34	29.34	-		-		-				-		-			-
Post Top 8,000-12,000 Lumens			-	41.70	41.70	41.70	-		-		-						-			-
Flood 17,500-22,500 Lumens			-	33.39	33.39	33.39	-		-		-						-			-
Unbilled Test Year Revenues							231										231			231
base fuel	4,533,547	1,346,244	1,957,196	0.02612	0.03380	0.03380	230,072						34,818				264,890			264,890
FAC							76,194													
HEAP Charge							-													
System Sales Clause							3,621													
Capacity Charge							-													
Environmental Surcharge							95,423					20,245					20,245			
Purchased Power Adjustment							7,788													
Decommissioning Rider							-													
Economic Development Charge							-													
Fed Tax Cut							(3,534)													
Total							**$ 1,905,482**					**$ 20,245**	**$ 34,818**	**$ -**	**-**	**-**	**$ 1,781,053**			**$ 1,999,546**

KENTUCKY POWER COMPANY
TYPICAL ELECTRIC BILL COMPARISON
GOING LEVEL VS PROPOSED RATES

Current Tariff	Proposed Tariff	Billing Demand Peak	Billing Demand O P Exc	Metered Energy	Current Bill	Proposed Bill	Bill Increase	% Change
RS	**RS**			100	$ 38.50	$ 49.02	$ 10.52	27.3%
		--	--	200	$ 54.35	$ 68.75	$ 14.40	26.5%
		--	--	300	$ 70.21	$ 88.47	$ 18.26	26.0%
		--	--	400	$ 86.06	$ 108.18	$ 22.13	25.7%
		--	--	500	$ 101.91	$ 127.91	$ 26.00	25.5%
		--	--	600	$ 117.77	$ 147.63	$ 29.86	25.4%
		--	--	700	$ 133.62	$ 163.87	$ 30.25	22.6%
		--	--	800	$ 149.47	$ 180.09	$ 30.62	20.5%
		--	--	900	$ 165.32	$ 196.32	$ 31.00	18.7%
		--	--	1,000	$ 181.18	$ 212.56	$ 31.38	17.3%
		--	--	1,100	$ 197.03	$ 228.78	$ 31.75	16.1%
		--	--	1,210	$ 214.47	$ 246.64	$ 32.17	15.0%
		--	--	1,300	$ 228.74	$ 261.25	$ 32.52	14.2%
		--	--	1,400	$ 244.59	$ 277.47	$ 32.88	13.4%
		--	--	1,500	$ 260.44	$ 293.71	$ 33.27	12.8%
		--	--	1,600	$ 276.30	$ 309.93	$ 33.64	12.2%
		--	--	1,700	$ 292.15	$ 326.16	$ 34.02	11.6%
		--	--	1,800	$ 307.99	$ 342.40	$ 34.41	11.2%
		--	--	1,900	$ 323.85	$ 358.62	$ 34.77	10.7%
		--	--	2,000	$ 339.70	$ 374.85	$ 35.16	10.4%
		--	--	2,001	$ 339.86	$ 390.56	$ 50.70	14.9%
		--	--	2,500	$ 418.97	$ 471.55	$ 52.58	12.5%
		--	--	3,000	$ 498.23	$ 552.70	$ 54.48	10.9%
		--	--	3,500	$ 577.49	$ 633.86	$ 56.37	9.8%
		--	--	4,000	$ 656.76	$ 715.02	$ 58.26	8.9%
		--	--	4,500	$ 736.02	$ 796.17	$ 60.15	8.2%
		--	--	5,000	$ 815.29	$ 877.32	$ 62.04	7.6%
RS-TOD	**RS-TOD**	--	--	500	$ 99.34	$ 113.26	$ 13.92	14.0%
On-Peak %	30%	--	--	750	$ 136.03	$ 153.57	$ 17.54	12.9%
Off-Peak %	70%	--	--	1,000	$ 172.71	$ 193.89	$ 21.18	12.3%
		--	--	1,500	$ 246.08	$ 274.51	$ 28.43	11.6%
		--	--	2,000	$ 319.44	$ 355.12	$ 35.68	11.2%
		--	--	3,000	$ 466.16	$ 516.37	$ 50.20	10.8%
GS-SEC		-	-	250	$ 74.87	$ 84.02	$ 9.14	12.2%
		-	-	350	$ 91.17	$ 102.56	$ 11.39	12.5%
		-	-	455	$ 108.29	$ 122.04	$ 13.76	12.7%
		-	-	750	$ 156.37	$ 176.75	$ 20.38	13.0%
		-	-	1,000	$ 197.12	$ 223.10	$ 25.98	13.2%
		-	-	2,000	$ 360.13	$ 408.56	$ 48.43	13.4%
		-	-	4,000	$ 686.12	$ 779.45	$ 93.33	13.6%
GS-SEC		15	-	2,738	$ 529.59	$ 623.31	$ 93.72	17.7%
25%	25%	25	-	4,563	$ 923.47	$ 1,113.94	$ 190.47	20.6%
		31		5,658	$ 1,141.93	$ 1,375.58	$ 233.65	20.5%
		50	-	9,125	$ 1,833.60	$ 2,204.03	$ 370.42	20.2%
		75	-	13,688	$ 2,743.87	$ 3,294.26	$ 550.38	20.1%
GS-SEC		15	-	5,475	$ 957.89	$ 1,098.21	$ 140.32	14.6%
50%	50%	25	-	9,125	$ 1,587.68	$ 1,814.55	$ 226.87	14.3%
		31		11,315	$ 1,965.57	$ 2,244.34	$ 278.77	14.2%
		50		18,250	$ 3,162.17	$ 3,605.38	$ 443.21	14.0%
		75	-	27,375	$ 4,736.65	$ 5,396.22	$ 659.58	13.9%
GS-PRI		15	-	2,738	$ 584.69	$ 689.36	$ 104.67	17.9%
25%	25%	25	-	4,563	$ 937.20	$ 1,128.21	$ 191.01	20.4%
		40		7,300	$ 1,427.96	$ 1,715.65	$ 287.68	20.1%
		50		9,125	$ 1,755.14	$ 2,107.26	$ 352.12	20.1%
		75		13,688	$ 2,573.11	$ 3,086.31	$ 513.20	19.9%
		90	-	16,425	$ 3,063.87	$ 3,673.74	$ 609.87	19.9%

KENTUCKY POWER COMPANY
TYPICAL ELECTRIC BILL COMPARISON
GOING LEVEL VS PROPOSED RATES

Current Tariff	Proposed Tariff	Billing Demand Peak	Billing Demand O P Exc	Metered Energy	Current Bill	Proposed Bill	Bill Increase	% Change
GS-PRI		25	-	9,125	$ 1,532.75	$ 1,758.57	$ 225.82	14.7%
50%	50%	43	-	15,695	$ 2,550.49	$ 2,917.34	$ 366.85	14.4%
		50		18,250	$ 2,946.27	$ 3,367.97	$ 421.70	14.3%
		60		21,900	$ 3,511.69	$ 4,011.73	$ 500.05	14.2%
		85		31,025	$ 4,925.20	$ 5,621.12	$ 695.93	14.1%
		95	-	34,675	$ 5,490.61	$ 6,264.87	$ 774.27	14.1%
GS-SUB		15	-	2,738	$ 941.56	$ 1,012.67	$ 71.11	7.6%
25%	25%	25	-	4,563	$ 1,251.93	$ 1,394.52	$ 142.59	11.4%
		40		7,300	$ 1,683.22	$ 1,903.10	$ 219.88	13.1%
		50		9,125	$ 1,970.75	$ 2,242.15	$ 271.40	13.8%
		75		13,688	$ 2,689.59	$ 3,089.79	$ 400.20	14.9%
		90	-	16,425	$ 3,120.87	$ 3,598.37	$ 477.50	15.3%
GS-SUB		25	-	9,125	$ 1,798.96	$ 1,975.21	$ 176.25	9.8%
50%	50%	43	-	15,695	$ 2,710.37	$ 3,003.61	$ 293.24	10.8%
		52		18,980	$ 3,166.08	$ 3,517.80	$ 351.72	11.1%
		60		21,900	$ 3,571.17	$ 3,974.88	$ 403.71	11.3%
		85		31,025	$ 4,837.02	$ 5,403.21	$ 566.19	11.7%
		95	-	34,675	$ 5,343.36	$ 5,974.53	$ 631.17	11.8%
LGS-SEC	**LGS-SEC**	100	-	29,200	$ 5,095.51	$ 5,910.70	$ 815.19	16.0%
Load Factor	40%	150	-	43,800	$ 7,585.63	$ 8,800.17	$ 1,214.55	16.0%
		200	-	58,400	$ 10,075.72	$ 11,689.63	$ 1,613.91	16.0%
		300	-	87,600	$ 15,055.93	$ 17,468.55	$ 2,412.62	16.0%
		500	-	146,000	$ 25,016.33	$ 29,026.39	$ 4,010.06	16.0%
LGS-SEC	**LGS-SEC**	100	-	36,500	$ 5,923.44	$ 6,847.89	$ 924.45	15.6%
Load Factor	50%	170	-	62,050	$ 9,989.13	$ 11,549.17	$ 1,560.04	15.6%
		250	-	91,250	$ 14,635.64	$ 16,922.05	$ 2,286.42	15.6%
		500	-	182,500	$ 29,155.95	$ 33,712.31	$ 4,556.36	15.6%
		750	-	273,750	$ 43,676.28	$ 50,502.58	$ 6,826.30	15.6%
LGS-SEC	**LGS-SEC**	100	-	43,800	$ 6,751.37	$ 7,785.08	$ 1,033.71	15.3%
Load Factor	60%	170	-	74,460	$ 11,396.60	$ 13,142.37	$ 1,745.78	15.3%
		250	-	109,500	$ 16,705.44	$ 19,265.01	$ 2,559.56	15.3%
		500	-	219,000	$ 33,295.59	$ 38,398.24	$ 5,102.66	15.3%
		750	-	328,500	$ 49,885.72	$ 57,531.46	$ 7,645.75	15.3%
LGS-SEC	**LGS-SEC**	100	-	51,100	$ 7,579.30	$ 8,722.26	$ 1,142.96	15.1%
Load Factor	70%	170	-	86,870	$ 12,804.07	$ 14,735.60	$ 1,931.52	15.1%
		250	-	127,750	$ 18,775.27	$ 21,607.99	$ 2,832.71	15.1%
		500	-	255,500	$ 37,435.20	$ 43,084.16	$ 5,648.96	15.1%
		750	-	383,250	$ 56,095.16	$ 64,560.36	$ 8,465.20	15.1%
LGS-PRI	**LGS-PRI**	125	-	36,500	$ 5,796.90	$ 6,764.32	$ 967.43	16.7%
Load Factor	40%	225	-	65,700	$ 10,296.99	$ 12,018.60	$ 1,721.61	16.7%
		315	-	91,980	$ 14,347.07	$ 16,747.42	$ 2,400.35	16.7%
		550	-	160,600	$ 24,922.28	$ 29,094.95	$ 4,172.67	16.7%
		750	-	219,000	$ 33,922.46	$ 39,603.48	$ 5,681.02	16.7%
LGS-PRI	**LGS-PRI**	125	-	45,625	$ 6,740.98	$ 7,839.30	$ 1,098.32	16.3%
Load Factor	50%	225	-	82,125	$ 11,996.32	$ 13,953.52	$ 1,957.20	16.3%
		315	-	114,975	$ 16,726.13	$ 19,456.32	$ 2,730.19	16.3%
		550	-	200,750	$ 29,076.19	$ 33,824.75	$ 4,748.56	16.3%
		750	-	273,750	$ 39,586.88	$ 46,053.20	$ 6,466.32	16.3%
LGS-PRI	**LGS-PRI**	125	-	54,750	$ 7,685.05	$ 8,914.25	$ 1,229.20	16.0%
Load Factor	60%	225	-	98,550	$ 13,695.65	$ 15,888.43	$ 2,192.79	16.0%
		315	-	137,970	$ 19,105.19	$ 22,165.21	$ 3,060.02	16.0%
		550	-	240,900	$ 33,230.11	$ 38,554.55	$ 5,324.45	16.0%
		750	-	328,500	$ 45,251.31	$ 52,502.94	$ 7,251.62	16.0%
LGS-PRI	**LGS-PRI**	125	-	63,875	$ 8,629.12	$ 9,989.20	$ 1,360.08	15.8%
Load Factor	70%	225	-	114,975	$ 15,394.97	$ 17,823.35	$ 2,428.38	15.8%
		315	-	160,965	$ 21,484.26	$ 24,874.10	$ 3,389.84	15.8%
		550	-	281,050	$ 37,384.01	$ 43,284.35	$ 5,900.33	15.8%
		750	-	383,250	$ 50,915.74	$ 58,952.68	$ 8,036.94	15.8%
LGS-SUB	**LGS-SUB**	250	-	73,000	$ 9,454.71	$ 10,972.65	$ 1,517.94	16.1%
Load Factor	40%	350	-	102,200	$ 12,883.12	$ 14,961.63	$ 2,078.51	16.1%
		450	-	131,400	$ 16,311.55	$ 18,950.63	$ 2,639.08	16.2%
		600	-	175,200	$ 21,454.16	$ 24,934.12	$ 3,479.96	16.2%
		750	-	219,000	$ 26,596.79	$ 30,917.61	$ 4,320.82	16.2%

KENTUCKY POWER COMPANY
TYPICAL ELECTRIC BILL COMPARISON
GOING LEVEL VS PROPOSED RATES

Current Tariff	Proposed Tariff	Billing Demand Peak	Billing Demand O P Exc	Metered Energy	Current Bill	Proposed Bill	Bill Increase	% Change
LGS-SUB	**LGS-SUB**	250	-	91,250	$ 10,950.30	$ 12,647.54	$ 1,697.24	15.5%
Load Factor	50%	350	-	127,750	$ 14,976.96	$ 17,306.50	$ 2,329.54	15.6%
		450	-	164,250	$ 19,003.61	$ 21,965.45	$ 2,961.84	15.6%
		600	-	219,000	$ 25,043.60	$ 28,953.89	$ 3,910.29	15.6%
		750	-	273,750	$ 31,083.57	$ 35,942.32	$ 4,858.75	15.6%
LGS-SUB	**LGS-SUB**	250	-	109,500	$ 12,445.90	$ 14,322.45	$ 1,876.55	15.1%
Load Factor	60%	350	-	153,300	$ 17,070.80	$ 19,651.37	$ 2,580.57	15.1%
		450	-	197,100	$ 21,695.68	$ 24,980.28	$ 3,284.60	15.1%
		600	-	262,800	$ 28,633.03	$ 32,973.66	$ 4,340.63	15.2%
		750	-	328,500	$ 35,570.36	$ 40,967.03	$ 5,396.67	15.2%
LGS-SUB	**LGS-SUB**	250	-	127,750	$ 13,941.50	$ 15,997.36	$ 2,055.86	14.7%
Load Factor	70%	350	-	178,850	$ 19,164.63	$ 21,996.23	$ 2,831.61	14.8%
		450	-	229,950	$ 24,387.76	$ 27,995.12	$ 3,607.36	14.8%
		600	-	306,600	$ 32,222.46	$ 36,993.44	$ 4,770.98	14.8%
		750	-	383,250	$ 40,057.16	$ 45,991.75	$ 5,934.59	14.8%
LGS-TRAN	**LGS-TRAN**	250	-	91,250	$ 10,796.43	$ 12,459.47	$ 1,663.03	15.4%
Load Factor	50%	350	-	127,750	$ 14,761.54	$ 17,043.19	$ 2,281.65	15.5%
		450	-	164,250	$ 18,726.64	$ 21,626.91	$ 2,900.27	15.5%
		600	-	219,000	$ 24,674.29	$ 28,502.50	$ 3,828.20	15.5%
LGS-TRAN	**LGS-TRAN**	250	-	109,500	$ 12,271.84	$ 14,108.81	$ 1,836.98	15.0%
Load Factor	60%	350	-	153,300	$ 16,827.10	$ 19,352.29	$ 2,525.18	15.0%
		450	-	197,100	$ 21,382.37	$ 24,595.74	$ 3,213.36	15.0%
		600	-	262,800	$ 28,215.27	$ 32,460.94	$ 4,245.67	15.0%
LGS-TRAN	**LGS-TRAN**	250	-	127,750	$ 13,747.26	$ 15,758.17	$ 2,010.91	14.6%
Load Factor	70%	350	-	178,850	$ 18,892.68	$ 21,661.37	$ 2,768.69	14.7%
		450	-	229,950	$ 24,038.11	$ 27,564.58	$ 3,526.46	14.7%
		600	-	306,600	$ 31,756.27	$ 36,419.38	$ 4,663.12	14.7%
LGS-TRAN	**LGS-TRAN**	250	-	146,000	$ 15,222.66	$ 17,407.52	$ 2,184.86	14.4%
Load Factor	80%	350	-	204,400	$ 20,958.26	$ 23,970.46	$ 3,012.20	14.4%
		450	-	262,800	$ 26,693.85	$ 30,533.40	$ 3,839.56	14.4%
		600	-	350,400	$ 35,297.24	$ 40,377.81	$ 5,080.57	14.4%
IGS-SEC	**IGS-SEC**	1,000	0	474,500	$ 58,289.62	$ 67,783.73	$ 9,494.10	16.3%
Load Factor	65%	5,000	0	2,372,500	$ 290,144.36	$ 337,614.86	$ 47,470.50	16.4%
		10,000	0	4,745,000	$ 579,962.80	$ 674,903.79	$ 94,940.99	16.4%
		15,000	0	7,117,500	$ 869,781.23	$ 1,012,192.72	$ 142,411.49	16.4%
		20,000	0	9,490,000	$ 1,159,599.65	$ 1,349,481.63	$ 189,881.98	16.4%
		1,000	200	474,500	$ 58,722.63	$ 68,273.22	$ 9,550.58	16.3%
		5,000	500	2,372,500	$ 291,226.89	$ 338,838.59	$ 47,611.70	16.3%
		10,000	500	4,745,000	$ 581,045.33	$ 676,127.51	$ 95,082.19	16.4%
		15,000	750	7,117,500	$ 871,405.02	$ 1,014,028.31	$ 142,623.29	16.4%
		20,000	1,000	9,490,000	$ 1,161,764.71	$ 1,351,929.08	$ 190,164.38	16.4%
IGS-SEC	**IGS-SEC**	1,000	0	620,500	$ 66,186.35	$ 76,733.55	$ 10,547.19	15.9%
Load Factor	85%	5,000	0	3,102,500	$ 329,628.01	$ 382,363.94	$ 52,735.94	16.0%
		10,000	0	6,205,000	$ 658,930.09	$ 764,401.95	$ 105,471.86	16.0%
		15,000	0	9,307,500	$ 988,232.16	$ 1,146,439.96	$ 158,207.80	16.0%
		20,000	0	12,410,000	$ 1,317,534.23	$ 1,528,477.95	$ 210,943.72	16.0%
		1,000	200	620,500	$ 66,619.36	$ 77,223.04	$ 10,603.67	15.9%
		5,000	500	3,102,500	$ 330,710.53	$ 383,587.67	$ 52,877.14	16.0%
		10,000	500	6,205,000	$ 660,012.62	$ 765,625.68	$ 105,613.06	16.0%
		15,000	750	9,307,500	$ 989,855.95	$ 1,148,275.55	$ 158,419.60	16.0%
		20,000	1,000	12,410,000	$ 1,319,699.28	$ 1,530,925.40	$ 211,226.12	16.0%
IGS-PRI	**IGS-PRI**	1,000	0	474,500	$ 55,045.57	$ 64,056.69	$ 9,011.12	16.4%
Load Factor	65%	5,000	0	2,372,500	$ 273,924.08	$ 318,979.69	$ 45,055.61	16.4%
		10,000	0	4,745,000	$ 547,522.22	$ 637,633.44	$ 90,111.21	16.5%
		15,000	0	7,117,500	$ 821,120.37	$ 956,287.19	$ 135,166.82	16.5%
		20,000	0	9,490,000	$ 1,094,718.50	$ 1,274,940.93	$ 180,222.42	16.5%
		1,000	200	474,500	$ 55,464.46	$ 64,529.71	$ 9,065.25	16.3%
		5,000	500	2,372,500	$ 274,971.31	$ 320,162.23	$ 45,190.92	16.4%
		10,000	500	4,745,000	$ 548,569.45	$ 638,815.98	$ 90,246.53	16.5%
		15,000	750	7,117,500	$ 822,691.21	$ 958,061.00	$ 135,369.79	16.5%
		20,000	1,000	9,490,000	$ 1,096,812.96	$ 1,277,306.01	$ 180,493.05	16.5%

KENTUCKY POWER COMPANY
TYPICAL ELECTRIC BILL COMPARISON
GOING LEVEL VS PROPOSED RATES

Current Tariff	Proposed Tariff	Billing Demand Peak	Billing Demand O P Exc	Metered Energy	Current Bill	Proposed Bill	Bill Increase	% Change
IGS-PRI	**IGS-PRI**	1,000	0	620,500	$ 62,686.33	$ 72,652.62	$ 9,966.29	15.9%
Load Factor	85%	5,000	0	3,102,500	$ 312,127.87	$ 361,959.30	$ 49,831.43	16.0%
		10,000	0	6,205,000	$ 623,929.81	$ 723,592.67	$ 99,662.87	16.0%
		15,000	0	9,307,500	$ 935,731.74	$ 1,085,226.04	$ 149,494.30	16.0%
		20,000	0	12,410,000	$ 1,247,533.67	$ 1,446,859.40	$ 199,325.73	16.0%
		1,000	200	620,500	$ 63,105.22	$ 73,125.64	$ 10,020.41	15.9%
		5,000	500	3,102,500	$ 313,175.10	$ 363,141.85	$ 49,966.75	16.0%
		10,000	500	6,205,000	$ 624,977.03	$ 724,775.22	$ 99,798.18	16.0%
		15,000	750	9,307,500	$ 937,302.58	$ 1,086,999.86	$ 149,697.27	16.0%
		20,000	1,000	12,410,000	$ 1,249,628.12	$ 1,449,224.49	$ 199,596.37	16.0%
IGS-SUB	**IGS-SUB**	1,000	0	474,500	$ 46,495.91	$ 53,988.97	$ 7,493.05	16.1%
Load Factor	65%	5,000	0	2,372,500	$ 228,737.77	$ 266,203.01	$ 37,465.24	16.4%
		10,000	0	4,745,000	$ 456,540.11	$ 531,470.58	$ 74,930.47	16.4%
		15,000	0	7,117,500	$ 684,342.43	$ 796,738.15	$ 112,395.72	16.4%
		20,000	0	9,490,000	$ 912,144.76	$ 1,062,005.71	$ 149,860.95	16.4%
		1,000	200	474,500	$ 46,907.74	$ 54,454.92	$ 7,547.18	16.1%
		5,000	500	2,372,500	$ 229,767.35	$ 267,367.91	$ 37,600.56	16.4%
		10,000	750	4,745,000	$ 458,084.47	$ 533,217.92	$ 75,133.45	16.4%
		15,000	1,000	7,117,500	$ 686,401.59	$ 799,067.94	$ 112,666.35	16.4%
		20,000	1,000	9,490,000	$ 914,203.92	$ 1,064,335.49	$ 150,131.58	16.4%
IGS-SUB	**IGS-SUB**	1,000	0	620,500	$ 54,062.80	$ 62,478.38	$ 8,415.58	15.6%
Load Factor	85%	5,000	0	3,102,500	$ 266,572.21	$ 308,650.08	$ 42,077.87	15.8%
		10,000	0	6,205,000	$ 532,208.98	$ 616,364.71	$ 84,155.72	15.8%
		15,000	0	9,307,500	$ 797,845.75	$ 924,079.34	$ 126,233.59	15.8%
		20,000	0	12,410,000	$ 1,063,482.51	$ 1,231,793.96	$ 168,311.45	15.8%
		1,000	200	620,500	$ 54,474.63	$ 62,944.34	$ 8,469.70	15.5%
		5,000	500	3,102,500	$ 267,601.79	$ 309,814.97	$ 42,213.18	15.8%
		10,000	750	6,205,000	$ 533,753.35	$ 618,112.05	$ 84,358.70	15.8%
		15,000	1,000	9,307,500	$ 799,904.90	$ 926,409.13	$ 126,504.22	15.8%
		20,000	1,000	12,410,000	$ 1,065,541.67	$ 1,234,123.74	$ 168,582.08	15.8%
IGS-TRAN	**IGS-TRAN**	5,000	0	3,102,500	$ 263,761.26	$ 305,078.52	$ 41,317.26	15.7%
Load Factor	85%	10,000	0	6,205,000	$ 525,929.33	$ 608,563.86	$ 82,634.54	15.7%
		15,000	0	9,307,500	$ 788,097.39	$ 912,049.19	$ 123,951.80	15.7%
		20,000	0	12,410,000	$ 1,050,265.44	$ 1,215,534.52	$ 165,269.07	15.7%
		5,000	500	3,102,500	$ 264,779.07	$ 306,231.65	$ 41,452.58	15.7%
		10,000	750	6,205,000	$ 527,456.04	$ 610,293.55	$ 82,837.51	15.7%
		15,000	1,000	9,307,500	$ 790,133.01	$ 914,355.44	$ 124,222.43	15.7%
		20,000	1,000	12,410,000	$ 1,052,301.06	$ 1,217,840.77	$ 165,539.71	15.7%

Tariff Class	Customer Classification	Current Test Year Revenue**	General Base Rate	Generation Rider Increase	Proposed Total Net Increase	Proposed Revenue	Percent Change
		a	b	c	d = b+c	e = a+d	f = d/a
RS*	RS	$ 286,735,722	$ 32,866,578	$ 9,808,321	$ 42,674,900	$ 329,410,621	14.9%
GS*	GS	$ 105,637,778	$ 12,003,625	$ 2,502,200	$ 14,505,824	$ 120,143,602	13.7%
LGS*	LGS	$ 67,756,853	$ 8,068,219	$ 1,662,560	$ 9,730,780	$ 77,487,633	14.4%
IGS	IGS	$ 182,038,170	$ 21,003,429	$ 6,278,025	$ 27,281,453	$ 209,319,623	15.0%
MW	MW	$ 242,812	$ 27,831	$ 4,891	$ 32,722	$ 275,534	13.5%
OL	OL	$ 9,318,114	$ 1,084,693	$ 25,880	$ 1,110,573	$ 10,428,687	11.9%
SL	SL	$ 1,905,482	$ 218,492	$ 6,583	$ 225,075	$ 2,130,557	11.8%
COGEN/SPP	COGEN/SPP	N/A	NA	NA	N/A	N/A	N/A
		$ 653,634,929	$ 75,272,868	$ 20,288,460	$ 95,561,328	$ 749,196,257	14.6%

* TOD tariffs have been included in the major class they belong to
** Test Year Billing Analysis Revenue
*** Proposed rate billing analysis, differs from proposed increase by revenue verification (rounding) differences

Filing Requirement
807KAR5:001, Section 16 (4)(i)

Rate Base Adj #		Section V Exhibit 1 Schedule 3 Capitalization	Section V Exhibit 1 Schedule 4 Rate Base	Difference in Capitalization & Rate Base
	Totals from Balance Sheet Detail:	2,445,357,960	2,065,208,337	380,149,624
	Adjustments			
	Proforma Debt Adjustment	-		-
	FRECO A/C 124 Property	(655,168)		(655,168)
	Non-Utility	(502,366)		(502,366)
	Subtotal	2,444,200,426	2,065,208,337	378,992,090
	Jurisdictional Allocation & Non-Applicable ADIT Adjustment	(506,356,891)	9,109,547	(515,466,438)
	Subtotal	1,937,843,536	2,074,317,884	(136,474,348)
	Going-Level Adjustments to Cash Working Capital & Other Ratebase Items			
56	Cash Working Capital	-	(60,772,165)	60,772,165
	Removal of Mitchell FGD Consumables	(1,025,060)	-	(1,025,060)
57	FGD Movement from Base to Environmental (Mitchell)	(113,080,671)	(114,105,731)	1,025,060
58	Removal NERC Compliance Asset from Cap.	(2,950,021)	(341,158)	(2,608,863)
52	Turbine Reservation Fee	-	10,000,000	(10,000,000)
51-A & 51-B	Mitchell Non-ELG	-	-	-
50	Vegetation Management ROW Widening	18,000,000	18,000,000	-
18	Wholesale Load Removal		18,200,755	(18,200,755)
49	Removal Mitchell from Rate Base and Cost of Service		(127,654,870)	127,654,870
55	Total ADIT Adjustment		54,614,595	(54,614,595)
	Adjustment Subtotals	(99,055,752)	(202,058,574)	103,002,822
	Total	**1,838,787,784**	**1,872,259,310**	**(33,471,526)**

KENTUCKY POWER COMPANY

Line No.	Description			
1	Total KPSC Jurisdiction Capitalization	(Section V, Schedule 1, line 18)	$	1,838,787,784
2	Total KPSC Jurisdiction Rate Base	(Section V, Schedule 1, line 16)	$	1,872,259,310
3	Difference (Capitalization less Rate Base)		**$**	**(33,471,526)**
	Summary of Differences			
	Assets			
4	Net Plant			0
5	Other Property and Investments			48,750,389
6	Cash and Cash Equivalents			1,128,688
7	Accounts Receivable Net			35,538,556
8	Accrued Utility Revenues			(4,325,041)
9	Energy Trading Contracts			3,015,258
10	Prepayments and Other Current Assets			(52,604,787)
11	Regulatory Assets			741,366,386
12	Unamortized Debt			3,957,052
13	Other Deferred Debits			24,339,119
14	Accumulated Deferred Income Taxes			49,778,733
15	Subtotal (4 through 14)			850,944,355
				1,653,138,321
	Capital and Liabilities			
16	Long Term Debt			564,969
17	Obligations Under Capital Leases - Noncurrent			(4,060,463)
18	Accumulated Provisions - Misc. - NonCurrent			(99,978,612)
19	Accounts Payable			(112,514,279)
20	Trading Deposits			0
21	Taxes Accrued			(24,486,480)
22	Interest Accrued			(14,731,344)
23	Obligations Under Capital Leases - Current			(621,646)
24	Energy Contracts			(43,669)
25	Other Current and Accrued Liabilities			(10,553,622)
26	Deferred Income Taxes			(83,417,723)
27	Regulatory Liabilities			(116,900,882)
28	Other Deferred Credits			(11,314,268)
29	Subtotal (16 through 29)			(478,058,021)
30	Total (14 + 29)			**372,886,334**
31	Less: AFUDC in CWIP	(Section V, Schedule 4, column 2, line 212)		(7,263,290)
32	Subtotal (31)			7,263,290
33	**Difference (pre-adjustments) (30 + 33)**			**380,149,624**
	Effect of Adjustments			
34	Adjustments to Capitalization			(1,157,534)
35	Jurisdictional Adjustment			(515,466,438)
36	Adjustments to Cash Working Capital			60,772,165
37	Adjustments to Rate Base			42,230,657
38	Subtotal (34 through 37)			(413,621,150)
39	**Overall Difference (34 + 39)**			**(33,471,526)**

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1010001	Plant in Service	3,364,986,012	A		3,364,986,012	3,364,986,012	0
1010008	Cloud Implement - PIS	3,189,990	A		3,189,990	3,189,990	0
1011001	Capital Leases	1,449,571			1,449,571	1,449,571	0
1011012	Accrued Capital Leases	0			0	0	0
1011031	Operating Lease	3,680,847			3,680,847	3,680,847	0
1011032	Accrued Operating Leases	492,985			492,985	492,985	0
1011036	Prov - Operating Lease Assets	(516,593)			(516,593)	(516,593)	0
1060001	Const Not Classifd	284,377,331	B		284,377,331	284,377,331	0
1060007	Cloud Implement - CCNC	11,402	B		11,402	11,402	0
1823022	HRJ 765kV Post Service AFUDC	250,824			250,824	250,824	0
1823054	HRJ 765kV Depreciation Expense	39,063			39,063	39,063	0
	Plant In Service	3,657,961,431			3,657,961,431	3,657,961,431	0
1011006	Prov-Leased Assets	(463,950)			(463,950)	(463,950)	0
	ELECTRIC UTILITY PLANT	**3,657,497,481**			**3,657,497,481**	**3,657,497,481**	**0**
1080001	A/P for Deprec of Plt	1,295,377,633			1,295,377,633	1,295,377,633	0
1080005	RWIP - Project Detail	(16,969,951)			(16,969,951)	(16,969,951)	0
1080011	Cost of Removal Reserve	122,500,162			122,500,162	122,500,162	0
1080013	ARO Removal Deprec - Accretion	0			0	0	
1080026	Cloud Compute Implement Costs	1,095,673			1,095,673	1,095,673	0
	less Accum Provision - Depre, Depl	1,402,003,517	C		**1,402,003,517**	**1,402,003,517**	0
1110001	A/P for Amort of Plt	59,074	D		59,074	59,074	0
1110007	Cloud Implement - A/P Amrt Plt	(0)	0		(0)	(0)	0
	less Accum Provision - Amort.	59,074			**59,074**	**59,074**	0
	NET ELECTRIC UTILITY PLANT	**2,255,434,890**			**2,255,434,890**	**2,255,434,890**	**0**
1050001	Held For Fut Use	801,671			801,671	801,671	0
1070001	CWIP - Project	164,314,687			164,314,687	164,314,687	0
1070007	Cloud Implementation Costs	1,898,852			1,898,852	1,898,852	0
		167,015,211			**167,015,211**	**167,015,211**	**0**

Subtotal as Shown in Application		
Original Cost - Electric Plant in Service	3,652,564,734	A + B
Accum Prov for Depr, Depl & Amort	1,402,062,591	C + D
Net Original Cost	5,054,627,325	

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1210001	Nonutility Property - Owned	502,366		502,366		502,366
	Gross NonUtility Property	502,366		**502,366**	0	502,366
1220001	Depr&Amrt of Nonutl Prop-Ownd	182,353		182,353		182,353
1220003	Depr&Amrt of Nonutl Prop-WIP	0		0		0
	Less Depr & Amort NonUtility Property	182,353		**182,353**	0	182,353
1240002	Oth Investments-Nonassociated	0		0		0
1240005	Spec Allowance Inv NOx	0		0		0
1240007	Deferred Compensation Benefits	0		0		0
1240027	Other Property - RWIP	(35,121)		(35,121)		(35,121)
1240028	Other Property - RETIRE	46,947		46,947	0	46,947
1240029	Other Property - CPR	655,168		655,168		655,168
1240092	Fbr Opt Lns-In Kind Sv-Invest	19,009		19,009		19,009
	Other Investments	686,003		**686,003**	0	686,003
1290001	Non-UMWA PRW Funded Position	38,308,637		38,308,637		38,308,637
1290002	SFAS 106 - Non-UMWA PRW	1,103,186		1,103,186		1,103,186
	Other Special Funds	39,411,824		**39,411,824**	0	39,411,824
1581000	SO2 Allowance Inventory	8,332,549		8,332,549	0	8,332,549
	Allowance - NonCurrent	8,332,549		**8,332,549**	0	8,332,549
1750002	Long-Term Unreal Gns - Non Aff	0		0		0
1750022	L/T Asset MTM Collateral	0		0		0
	Long Term Energy Trading Contracts	0		**0**		0
	OTHER PROPERTY AND INVESTMENTS	48,750,389		48,750,389	0	48,750,389
1310000	Cash	1,105,712		1,105,712		1,105,712
1340018	Spec Deposits - Elect Trading	1,613,024		1,613,024	1,613,024	0
1340043	Spec Deposit UBS Securities	0		0		0
1340048	Spec Deposits-Trading Contra	(134,731)		(134,731)	(134,731)	0
1340050	Spec Deposit Mizuho Securities	0		0		0
1340051	Spec Depost RBC	21,003		21,003	21,003	0
1340053	Deposits Flexible Spending	22,976		22,976		22,976
1340057	Wells Fargo Securities, LLC	820,553		820,553	820,553	0
	Cash and Cash Equivalents	3,448,538		**3,448,538**	2,319,850	1,128,688
1450000	Corp Borrow Prg (NR-Assoc)	0		0		0
	Advances to Affiliates	0		**0**		0
1420001	Customer A/R - Electric	45,894,739		45,894,739		45,894,739
1420014	Customer A/R-System Sales	612,985		612,985		612,985
1420019	Transmission Sales Receivable	7,092		7,092		7,092
1420022	Cust A/R - Factored	(44,553,929)		(44,553,929)		(44,553,929)
1420023	Cust A/R-System Sales - MLR	0		0		0
1420024	Cust A/R-Options & Swaps - MLR	(0)		(0)		(0)
1420027	Low Inc Energy Asst Pr (LIEAP)	619,976		619,976		619,976
1420028	Emergency LIEAP	9,904		9,904		9,904
1420033	Cooling Assistance Prg (COOL)	250		250		250
1420042	Cust A/R - Special Contracts	(0)		(0)		(0)
1420044	Customer A/R - Estimated	9,484,095		9,484,095		9,484,095
1420050	PJM AR Accrual	0		0		0
1420054	Accrued Power Brokers	0		0		0
1420058	Cust A/R-Contra-Home Warranty	(114,940)		(114,940)		(114,940)
1420059	AR PS Bill-Cust Home Warranty	19,768		19,768		19,768
1420060	PJM Trans Enhancement Refund	493,764		493,764		493,764
1420062	Emergency Rent Assist ERUAP	0		0		0
1420102	AR Peoplesoft Billing - Cust	3,232,712		3,232,712		3,232,712
1420103	AR Long-Term-Customer	0		0		0
	Acct Rec - Customers	15,706,416		**15,706,416**	0	15,706,416

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1430002	Allowances	0		0		0
1430022	2001 Employee Biweekly Pay Cnv	4,539		4,539		4,539
1430081	Damage Recovery - Third Party	(331)		(331)		(331)
1430083	Damage Recovery Offset Demand	0		0		0
1430101	Other Accounts Rec - Misc	0		0		0
1430102	AR Peoplesoft Billing - Misc	70,259		70,259		70,259
	Acct Rec - Miscellaneous	74,467		**74,467**	0	74,467
1440001	Uncoll Accts-Elect Receivables	0		0		0
1440002	Uncoll Accts-Other Receivables	372		372		372
	Acct Rec - AP for Uncollectible Accounts	372		**372**	0	372
1460001	A/R Assoc Co - InterUnit G/L	18,047,754		18,047,754		18,047,754
1460006	A/R Assoc Co - Intercompany	235,036		235,036		235,036
1460009	A/R Assoc Co - InterUnit A/P	4,583		4,583		4,583
1460011	A/R Assoc Co - Multi Pmts	1,330,559		1,330,559		1,330,559
1460025	Fleet - M4 - A/R	140,114		140,114		140,114
	Acct Rec - Associated Companies	19,758,046		**19,758,046**	0	19,758,046
	Accts Receivable	35,538,556		35,538,556		35,538,556
1510001	Fuel Stock - Coal	55,539,789		55,539,789	55,539,789	0
1510002	Fuel Stock - Oil	647,435		647,435	647,435	0
1510003	Fuel Stock - Gas	150,845		150,845	150,845	0
1510020	Fuel Stock Coal - Intransit	482,245		482,245	482,245	0
1520000	Fuel Stock Exp Undistributed	2,810,210		2,810,210	2,810,210	0
	Fuel Stock	59,630,524		**59,630,524**	**59,630,524**	0
1581000	SO2 Allowance Inventory	8,332,549		8,332,549	8,332,549	0
1581003	SO2 Allowance Inventory - Curr	74,758		74,758	74,758	0
1581009	CSAPR Current SO2 Inv	20,012		20,012	20,012	0
1581014	CSAPR Seas NOx Comp Inv - Curr	82,000		82,000	82,000	0
	Allowance Inventory	**8,509,319**		**8,509,319**	**8,509,319**	0
						0
1581000	SO2 Allowance Inventory	8,332,549		8,332,549	0	8,332,549
	Less SO2 Allowance Inventory	**8,332,549**		**8,332,549**	0	**8,332,549**
1540001	M&S - Regular	20,144,386		20,144,386	20,144,386	0
1540003	Material in Transit	1,551		1,551	1,551	
1540004	M&S - Exempt Material	85,727		85,727	85,727	0
1540006	M&S - Lime and Limestone	1,039,615		1,039,615	1,039,615	0
1540012	Materials & Supplies - Urea	267,326		267,326	267,326	0
1540013	Transportation Inventory	756,015		756,015	756,015	0
1540022	M&S-Lime & Limestone Intransit	0		0	0	0
1540023	M&S Inv - Urea In-Transit	547,478		547,478	547,478	0
1540033	Inventory Pending Inspection	0		0	0	0
	Plant Materials and Supplies	22,842,097		**22,842,097**	**22,842,097**	0
1730000	Accrued Utility Revenues	7,640,140		7,640,140		7,640,140
1730002	Acrd Utility Rev-Factored-Assc	(11,965,180)		(11,965,180)		(11,965,180)
	Accrued Utility Revenues	(4,325,041)		**(4,325,041)**	0	(4,325,041)
1750001	Curr. Unreal Gains - NonAffil	3,015,258		3,015,258		3,015,258
1750002	Acrd Utility Rev-Factored-Assc	0		0		0
	Energy Trading	3,015,258		**3,015,258**	0	**3,015,258**

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1650001	Prepaid Insurance	242,778		242,778	242,778	0
165000221	Prepaid Taxes	0		0	0	0
165000222	Prepaid Taxes	0		0	0	0
1650006	Other Prepayments	66,121		66,121	66,121	0
1650009	Prepaid Carry Cost-Factored AR	125,788		125,788	125,788	0
1650010	Prepaid Pension Benefits	14,250,943		14,250,943	14,250,943	0
165001124	Prepaid Sales Taxes	0		0	0	0
165001125	Prepaid Sales Taxes	332,475		332,475	332,475	0
165001224	Prepaid Use Taxes	0		0	0	0
165001225	Prepaid Use Taxes	81,180		81,180	81,180	0
1650014	FAS 158 Qual Contra Asset	(14,250,943)		(14,250,943)		(14,250,943)
1650021	Prepaid Insurance - EIS	465,575		465,575	465,575	0
1650023	Prepaid Lease	38,742		38,742	38,742	0
1650035	PRW Without MED-D Benefits	34,208,984		34,208,984	34,208,984	0
1650036	PRW for Med-D Benefits	0		0	0	0
1650037	FAS158 Contra-PRW Exclud Med-D	(34,208,984)		(34,208,984)		(34,208,984)
1650041	Prepaid Regulatory Fees	79,428		79,428	79,428	0
1720000	Rents Receivable	4,187,689		4,187,689		4,187,689
	Prepayments & Other Current Assets	(2,712,774)		(2,712,774)	49,892,012	(52,604,787)
	CURRENT ASSETS	125,946,478		125,946,478	143,193,802	(17,247,324)
1823000	Other Regulatory Assets	2,506,318		2,506,318		2,506,318
1823007	SFAS 112 Postemployment Benef	2,784,067		2,784,067		2,784,067
1823009	DSM Incentives	4,577,025		4,577,025		4,577,025
1823010	Energy Efficiency Recovery	(65,375,617)		(65,375,617)		(65,375,617)
1823011	DSM Lost Revenues	16,328,416		16,328,416		16,328,416
1823012	DSM Program Costs	44,470,176		44,470,176		44,470,176
1823037	KY Steam Maint O/U	0		0		0
1823063	Unrecovered Fuel Cost	3,738,643		3,738,643		3,738,643
1823077	Unreal Loss on Fwd Commitments	11,658		11,658		11,658
1823078	Deferred Storm Expense	0		0		0
1823108	Reg Asset - Rate Case Expenses	585,006		585,006		585,006
1823115	Defd Equity Carry Chg-Non Fuel	0		0		0
1823118	BridgeCo TO Funding	0		0		0
1823120	Other PJM Integration	0		0		0
1823121	Carry Chgs-RTO Startup Costs	0		0		0
1823122	Alliance RTO Deferred Expense	0		0		0
1823165	REG ASSET FAS 158 QUAL PLAN	18,985,057		18,985,057		18,985,057
1823166	REG ASSET FAS 158 OPEB PLAN	(5,202,840)		(5,202,840)		(5,202,840)
1823167	REG Asset FAS 158 SERP Plan	(152,029)		(152,029)		(152,029)
1823188	Deferred Carbon Mgmt Research	0		0		0
1823299	SFAS 106 Medicare Subsidy	0		0		0
1823301	SFAS 109 Flow Thru Defd FIT	43,875,392		43,875,392		43,875,392
1823302	SFAS 109 Flow Thru Defrd SIT	102,763,385		102,763,385		102,763,385
1823306	Net CCS FEED Study Costs	526,624		526,624		526,624
182332821	FERC Formula Rates Under Recvr	32,790		32,790		32,790
182332822	FERC Formula Rates Under Recvr	41,565		41,565		41,565
182332823	FERC Formula Rates Under Recvr	272,661		272,661		272,661
182332824	FERC Formula Rates Under Recvr	72,095		72,095		72,095
182332825	FERC Formula Rates Under Recvr	10,551		10,551		10,551
1823376	Cost of Removal-Big Sandy Coal	(25,092,327)		(25,092,327)		(25,092,327)
1823377	NBV - AROs Retired Plants	53,338,465		53,338,465		53,338,465
1823378	M&S - Retiring Plants	3,015,785		3,015,785		3,015,785
1823379	Unrecovered Plant - Big Sandy	256,509,062		256,509,062		256,509,062
1823380	Spent AROs - Big Sandy Coal	110,647,175		110,647,175		110,647,175
1823410	BS1OR Unrecognized Equity CC	(946,743)		(946,743)		(946,743)
1823411	BS1OR Under Recovery CC	946,743		946,743		946,743
1823414	Capacity Charge Tariff Rev	0		0		0
1823429	Rockport Capacity Def-Eqty CC	(5,337,989)		(5,337,989)		(5,337,989)
1823430	Rockport Capacity CC Deferral	11,566,738		11,566,738		11,566,738
1823431	Rockport Capacity Deferral	39,643,828		39,643,828		39,643,828
1823515	IGCC Pre-Construction Costs	803,190		803,190		803,190
1823516	BS1OR Under Recovery	0		0		0
1823517	Big Sandy Recov O/U Balancing	(60,706,331)		(60,706,331)		(60,706,331)
1823518	BSRR Unit 2 O&M	951,577		951,577		951,577
1823519	Unrecovered Purch Power-PPA	0		0		0
1823520	Deferred Dep - Environmental	5,737,323		5,737,323		5,737,323
1823536	CC-NERC Compl/Cyber Unrec Eqty	(398,350)		(398,350)		(398,350)
1823537	CC-NERC Compliance/Cyber Sec	852,987		852,987		852,987
1823538	Def Depr-NERC Compli/Cybersec	2,938,409		2,938,409		2,938,409
1823547	Def Depr-Big Sandy Unit 1 Gas	0		0		0
1823550	Def Prop Tax-Big Sandy U1 Gas	0		0		0
1823557	CC-NERC Compl/Cyber Unrec Eqty	56,531,024		56,531,024		56,531,024
1823571	CC-NERC Compliance/Cyber Sec	0		0		0
1823620	2020 KY Storm Deferral	10,509,844		10,509,844		10,509,844
1823623	2021 KY Storm deferral	45,996,003		45,996,003		45,996,003

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1823655	NOLC Regulatory Asset	6,254,426		6,254,426		6,254,426
1823656	NOLC Reg Asset-Equity Carrying	(6,254,426)		(6,254,426)		(6,254,426)
1823685	KY ELG Deferral	0		0		0
1823698	2022 KY Major Storm Deferral	13,838,283		13,838,283		13,838,283
1823722	2023 KY Storm Deferral	8,415,089		8,415,089		8,415,089
1823727	KY Deferred Securitization Exp	2,714,138		2,714,138		2,714,138
1823741	Tariff DR CC Deferral	25,237,763		25,237,763		25,237,763
1823742	Tariff DR DeferredEquity CC	(10,442,625)		(10,442,625)		(10,442,625)
1823757	KY 2024 Storm Deferral	10,783,447		10,783,447		10,783,447
1823767	KY 2025 Storm Deferral	12,462,933		12,462,933		12,462,933
	Regulatory Assets	741,366,386		741,366,386	0	741,366,386

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1890004	Loss Rec Debt-Debentures	252,381		252,381		252,381
	Unamortized Loss on Reacquired Debt	252,381		252,381	0	252,381
1810002	Unamort Debt Exp - Inst Pur Cn	172,581		172,581		172,581
1810003	Unamort Debt Exp Notes Payable	10,370		10,370		10,370
1810006	Unamort Debt Exp - Sr Unsec Nt	3,521,721		3,521,721		3,521,721
	Unamortized Debt Expense	3,704,672		3,704,672	0	3,704,672
1840063	Corporate Charge Card Clearing	0		0		0
	Clearing Accounts	0		0	0	0
1830000	Prelimin Surv&Investgtn Chrgs	1,040,336		1,040,336		1,040,336
1830004	Prelim Survey & Invstgtn Resrv	0		0		0
1860000	MDD-Internal Billing Only	0		0		0
1860001	Allowances	(157,143)		(157,143)		(157,143)
1860002	Deferred Expenses	(29,916)		(29,916)		(29,916)
1860005	Unidentified Cash Receipts	0		0		0
1860006	Constructive Marketing Program	355		355		355
1860007	Billings and Deferred Projects	80,243		80,243		80,243
186000323	Deferred Property Taxes	224,194		224,194		224,194
186000324	Deferred Property Taxes	11,869,535		11,869,535		11,869,535
1860015	Billings Paid Union Benefits	8,004		8,004		8,004
1860077	Agency Fees - Factored A/R	1,132,736		1,132,736		1,132,736
186008124	Defd Property Tax - Cap Leases	0		0		0
186008125	Defd Property Tax - Cap Leases	386,340		386,340		386,340
1860087	Estimated Barging Bills	0		0		0
1860153	Unamortized Credit Line Fees	427,722		427,722		427,722
1860166	Def Lease Assets - Non Taxable	75,239		75,239		75,239
1860185	Long Term Assoc AR	9,252,141		9,252,141		9,252,141
1860192	Trnsrce OU Acctg for Def Asset	36,311		36,311		36,311
1860332	Prov Opr Lease Assets-Gen&Misc	(6,978)		(6,978)		(6,978)
	Other Deferred Debits	24,339,119		24,339,119	0	24,339,119
1900010	ADIT Federal - Pension OCI	0		0		0
1900011	ADIT Federal Non-UMWA PRW OCI	0		0		0
1900015	ADIT-Fed-Hdg-CF-Int Rate	0		0		0
1901001	Accum Deferred FIT - Other*	16,262,225		16,262,225	16,262,225	0
1901002	Accum Deferred SIT - Other	16,476,228		16,476,228	16,476,228	0
1902001	Accum Defd FIT - Oth Inc & Ded	(0)		(0)		(0)
1903001	Acc Dfd FIT - FAS109 Flow Thru	21,576,628		21,576,628		21,576,628
1904001	Accum Dfd FIT - FAS 109 Excess	28,202,105		28,202,105		28,202,105
	Accumulated Deferred Income Taxes	82,517,186		82,517,186	**32,738,453**	49,778,733
	TOTAL DEFERRED CHARGES	110,813,357		110,813,357	32,738,453	78,074,904
	TOTAL ASSETS	**3,449,326,712**		**3,449,326,712**	**2,598,382,356**	**850,944,355**
	CAPITALIZATION and LIABILITIES					
	COMMON STOCK					
2010001	Common Stock Issued-Affiliated	50,450,000	50,450,000	0	0	0
	Common Stock	50,450,000	50,450,000	0	0	0
2080000	Donations Recvd from Stckhldrs	523,324,094	523,324,094	0		0
2110000	Miscellaneous Paid-In Capital	(97,156)	(97,156)	0		0
2110018	DSIT Apportionment Adj.	2,811,185	2,811,185	0		0
2190006	OCI-Min Pen Liab FAS 158-Qual	0	0	0		0
2190007	OCI-Min Pen Liab FAS 158-OPEB	0	0	0		0
2190015	Accum OCI-Hdg-CF-Int Rate	0	0	0		0
	Paid-In-Capital	526,038,123	526,038,123	0	0	0
	Retained Earnings	418,670,024	418,670,024	0	0	0
	COMMON SHAREHOLDERS' EQUITY	995,158,147	995,158,147	0	0	0

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2240002	Installment Purchase Contracts	65,000,000	65,000,000	0		0
2240005	Other Long Term Debt - Other	0	0	0		0
2240006	Senior Unsecured Notes	1,000,000,000	1,000,000,000	0		0
2240505	Oth LTD - Other - Current	300,000,000	300,000,000	0		0
2240506	Senior Unsecured Notes-Current	0	0	0		0
	Senior Unsecured Notes	1,365,000,000	1,365,000,000	0		0
2260006	Unam Disc LTD-Dr-Sr Unsec Note	564,969	0	564,969	0	564,969
	Long-Term Debt	1,364,435,031	1,365,000,000	564,969	0	564,969
	CAPITALIZATION	2,359,593,178	2,360,158,147	564,969	0	564,969
2270001	Obligatns Undr Cap Lse-Noncurr	839,811		(839,811)		(839,811)
2270003	Accrued Noncur Lease Oblig	0		0		0
2270031	Oblig undr Oper Lease-Non Curr	2,816,883		(2,816,883)		(2,816,883)
2270033	Acrued Noncur Oper Lease Oblig	403,769		(403,769)		(403,769)
	Obligations Under Capital Lease-NonCurrent	4,060,463		(4,060,463)	0	(4,060,463)
2282003	Accm Prv I/D - Worker's Com	72,472		(72,472)		(72,472)
2282011	Accm Prv I/D - Asbestos - Curr	163,541		(163,541)		(163,541)
2282012	Accm Prv I/D - Asbestos	986,383		(986,383)		(986,383)
2283000	Accm Prv for Pensions&Benefits	215,927		(215,927)		(215,927)
2283002	Supplemental Savings Plan	1,427		(1,427)		(1,427)
2283005	SFAS 112 Postemployment Benef	1,461,535		(1,461,535)		(1,461,535)
2283006	SFAS 87 - Pensions	(84,739)		84,739		84,739
2283007	Perf Share Incentive Plan	0		0		0
2283013	Incentive Comp Deferral Plan	82,034		(82,034)		(82,034)
2283015	FAS 158 SERP Payable Long Term	(152,725)		152,725		152,725
2283016	FAS 158 Qual Payable Long Term	4,818,852		(4,818,852)		(4,818,852)
2284027	Econ. Development Fund NonCurr	0		0		0
2290002	Accumulated Provision Rate Relief	1,620,672		(1,620,672)		(1,620,672)
2300001	Asset Retirement Obligations	87,085,767		(87,085,767)		(87,085,767)
2300002	ARO - Current	3,620,144		(3,620,144)		(3,620,144)
2440002	LT Unreal Losses - Non Affil	88,004		(88,004)		(88,004)
2440022	L/T Liability MTM Collateral	(682)		682		682
	Accumlated Provision - Miscellanous	99,978,612		(99,978,612)	0	(99,978,612)
	Other NonCurrent Liabilities	104,039,075	0	(104,039,075)	0	(104,039,075)
2330000	Corp Borrow Program (NP-Assoc)	85,199,814	85,199,814	0		0
2320001	Accounts Payable - Regular	10,180,457		(10,180,457)		(10,180,457)
2320002	Unvouchered Invoices	38,990,852		(38,990,852)		(38,990,852)
2320003	Retention	2,491,381		(2,491,381)		(2,491,381)
2320008	Miscellaneous Liabilities	0		0		0
2320011	Uninvoiced Fuel	3,136,957		(3,136,957)		(3,136,957)
2320052	Accounts Payable - Purch Power	841,781		(841,781)		(841,781)
2320053	Elect Trad-Options&Swaps	0		(0)		(0)
2320054	Emission Allowance Trading	0		0		0
2320056	Gas Physicals	0		0		0
2320062	Broker Fees Payable	0		0		0
2320073	A/P Misc Dedic. Power	12,569		(12,569)		(12,569)
2320076	Corporate Credit Card Liab	380,725		(380,725)		(380,725)
2320077	INDUS Unvouchered Liabilities	2,423,370		(2,423,370)		(2,423,370)
2320079	Broker Commisn Spark/Merch Gen	0		0		0
2320083	PJM Net AP Accrual	2,467,208		(2,467,208)		(2,467,208)
2320086	Accrued Broker - Power	939,726		(939,726)		(939,726)
2320095	Home Warranty Payables	130,310		(130,310)		(130,310)
2320100	PJM Greenhat Default Payable	0		0		0
2320101	RTO AP Accrual for Cong Deriv	1,616,002		(1,616,002)		(1,616,002)
	A/P General	63,611,339		(63,611,339)	0	(63,611,339)
2340001	A/P Assoc Co - InterUnit G/L	44,809,994		(44,809,994)		(44,809,994)
2340011	A/P-Assc Co-AEPSC-Agent	0		0		0
2340025	A/P Assoc Co - CM Bills	40,480		(40,480)		(40,480)
2340027	A/P Assoc Co - Intercompany	237,983		(237,983)		(237,983)
2340029	A/P Assoc Co - AEPSC Bills	3,765,853		(3,765,853)		(3,765,853)
2340030	A/P Assoc Co - InterUnit A/P	40,787		(40,787)		(40,787)
2340032	A/P Assoc Co - Multi Pmts	425		(425)		(425)
2340035	Fleet - M4 - A/P	7,418		(7,418)		(7,418)
2340037	A/P Assoc-Global Borrowing Int	(0)		0	0	0
	A/P Associated Companies	48,902,940		(48,902,940)	0	(48,902,940)

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2350001	Customer Deposits-Active	38,090,280		(38,090,280)	(38,090,280)	0
2350003	Deposits - Trading Activity	367,914		(367,914)	(367,914)	0
	Customer Deposits	38,458,193		(38,458,193)	**(38,458,193)**	0
2360001	Federal Income Tax	1,812,722		(1,812,722)		(1,812,722)
2360002	State Income Taxes	(1,083,053)		1,083,053		1,083,053
236000215	State Income Taxes	0		0		0
236000216	State Income Taxes	0		0		0
236000217	State Income Taxes	0		0		0
236000218	State Income Taxes	0		0		0
236000219	State Income Taxes	0		0		0
236000220	State Income Taxes	0		0		0
236000221	State Income Taxes	0		0		0
236000222	State Income Taxes	0		0		0
236000223	State Income Taxes	0		0		0
2360003	Local Income Tax	(49,346)		49,346		49,346
236000319	Local Income Tax	0		0		0
2360004	FICA	66,001		(66,001)		(66,001)
2360005	Federal Unemployment Tax	71		(71)		(71)
2360006	State Unemployment Tax	69		(69)		(69)
236000718	State Sales and Use Taxes	0		0		0
236000722	State Sales and Use Taxes	0		(0)		(0)
236000723	State Sales and Use Taxes	0		0		0
236000724	State Sales and Use Taxes	0		0		0
236000725	State Sales and Use Taxes	150,348		(150,348)		(150,348)
236000821	Real Personal Property Taxes	0		0		0
236000822	Real Personal Property Taxes	687,410		(687,410)		(687,410)
236000823	Real Personal Property Taxes	860,629		(860,629)		(860,629)
236000824	Real Personal Property Taxes	19,604,697		(19,604,697)		(19,604,697)
236001217	State Franchise Taxes	(225,823)		225,823		225,823
236001218	State Franchise Taxes	174,650		(174,650)		(174,650)
236001219	State Franchise Taxes	243,115		(243,115)		(243,115)
236001220	State Franchise Taxes	48,643		(48,643)		(48,643)
236001323	State Business Occupatn Taxes	0		0		0
236001324	State Business Occupatn Taxes	0		0		0
236001325	State Business Occupatn Taxes	587,156		(587,156)		(587,156)
236001620	State Gross Receipts Tax	(1,541)		1,541		1,541
236001623	State Gross Receipts Tax	0		0		0
236001624	State Gross Receipts Tax	0		0		0
236001625	State Gross Receipts Tax	3,082		(3,082)		(3,082)
236001724	Municipal License Fees Accrd	(45)		45		45
236002222	State License Registration Tax	0		0		0
236003322	Pers Prop Tax-Cap Leases	0		0		0
236003323	Pers Prop Tax-Cap Leases	518,832		(518,832)		(518,832)
236003324	Pers Prop Tax-Cap Leases	398,971		(398,971)		(398,971)
236003325	Pers Prop Tax-Cap Leases	662,300		(662,300)		(662,300)
236003523	Real Prop Tax-Cap Leases	0		0		0
236003524	Real Prop Tax-Cap Leases	0		0		0
236003525	Real Prop Tax-Cap Leases	6,250		(6,250)		(6,250)
2360037	FICA - Incentive accrual	21,342		(21,342)		(21,342)
2360038	Reorg Payroll Tax Accrual	0		0		0
2360502	State Inc Tax-Short Term FIN48	0		0		0
2360601	Fed Inc Tax-Long Term FIN48	0		0		0
2360602	State Inc Tax-Long Term FIN48	0		0		0
2360702	SEC Accum Defd SIT - FIN 48	0		0		0
2360801	Federal Income Tax - IRS Audit	0		0		0
2360901	Accum Defd FIT- IRS Audit	0		0		0
	Taxes Accrued	24,486,480		(24,486,480)	0	(24,486,480)
2370002	Interest Accrued-Inst Pur Con	1,527,500		(1,527,500)		(1,527,500)
2370005	Interest Accrd-Other LT Debt	1,680,548		(1,680,548)		(1,680,548)
2370006	Interest Accrd-Sen Unsec Notes	10,904,894		(10,904,894)		(10,904,894)
2370007	Interest Accrd-Customer Depsts	618,403		(618,403)		(618,403)
2370018	Accrued Margin Interest	0		(0)		(0)
2370048	Acrd Int.- FIT Reserve - LT	0		0		0
2370348	Acrd Int. - SIT Reserve - LT	0		0		0
2370448	Acrd Int. - SIT Reserve - ST	0		0		0
	Interest Accrued	14,731,344		(14,731,344)	0	(14,731,344)
						0
2430001	Oblig Under Cap Leases - Curr	141,759		(141,759)		(141,759)
2430003	Accrued Cur Lease Oblig	0		0		0
2430031	Oblig undr Oper Lease -Current	390,671		(390,671)		(390,671)
2430033	Acrued Curent Oper Lease Oblig	89,216		(89,216)		(89,216)
	Obligation Under Capital Leases	621,646		(621,646)	0	(621,646)

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							0
2440001	Curr. Unreal Losses - NonAffil	177,718		(177,718)			(177,718)
2440002	LT Unreal Losses - Non Affil	88,004		(88,004)			(88,004)
2440021	S/T Liability MTM Collateral	(134,049)		134,049			134,049
2440022	L/T Liability MTM Collateral	(682)		682			682
	Energy Contracts Current	130,991		(130,991)	0		(130,991)
							0
2410001	Federal Income Tax Withheld	0		0			0
2410002	State Income Tax Withheld	0		0			0
2410003	Local Income Tax Withheld	0		0			0
2410004	State Sales Tax Collected	717,262		(717,262)			(717,262)
2410006	School District Tax Withheld	0		0			0
2410008	Franchise Fee Collected	361,907		(361,907)			(361,907)
2410009	KY Utility Gr Receipts Lic Tax	943,393		(943,393)			(943,393)
	Tax Collections Payable	2,022,562		(2,022,562)	0		(2,022,562)
2420514	Revenue Refunds Accrued	145,477		(145,477)			(145,477)
	Revenue Refunds Accured	145,477		(145,477)	0		(145,477)
2420504	Accrued Lease Expense	(3,927)		3,927			3,927
	Accrued Rents - NonAffiliated	(3,927)		3,927	0		3,927
	Accrued Rents	(3,927)		3,927	0		3,927
2420020	Vacation Pay - This Year	0		0			0
2420021	Vacation Pay - Next Year	2,561,787		(2,561,787)			(2,561,787)
	Accrued Vacations	2,561,787		(2,561,787)	0		(2,561,787)
2420051	Non-Productive Payroll	76,524		(76,524)			(76,524)
2420053	Perf Share Incentive Plan	0		0			0
	Miscellaneous Employee Benefits	76,524		(76,524)	0		(76,524)
	Employee Benefits	2,638,310		(2,638,310)	0		(2,638,310)
2420000	Misc Current & Accrued Liab	0		0			0
2420002	P/R Ded - Medical Insurance	91,851		(91,851)			(91,851)
2420003	P/R Ded - Dental Insurance	9,136		(9,136)			(9,136)
2420013	P/R Ded - LTD Ins Premiums	1,581		(1,581)			(1,581)
	Payroll Deductions	102,568		(102,568)	0		(102,568)
2420532	Adm Liab-Cur-S/Ins-W/C	195,428		(195,428)			(195,428)
	Accrued Workers' Compensation	195,428		(195,428)	0		(195,428)
2420027	FAS 112 CURRENT LIAB	1,322,528		(1,322,528)			(1,322,528)
2420046	FAS 158 SERP Payable - Current	696		(696)			(696)
2420071	P/R Ded - Vision Plan	3,395		(3,395)			(3,395)
2420072	P/R - Payroll Adjustment	0		0			0
2420076	P/R Savings Plan - Incentive	9,789		(9,789)			(9,789)
2420083	Active Med and Dental IBNR	0		0			0
2420088	Econ. Development Fund Curr	768,020		(768,020)			(768,020)
2420511	Control Cash Disburse Account	927,151		(927,151)			(927,151)
2420515	Severance Accrual	0		0			0
2420512	Unclaimed Funds	16,001		(16,001)			(16,001)
2420542	Acc Cash Franchise Req	111,356		(111,356)			(111,356)
2420558	Admitted Liab NC-Self/Ins-W/C	1,092,738		(1,092,738)			(1,092,738)
242059224	Sales Use Tax - Leased Equip	0		0			0
242059225	Sales Use Tax - Leased Equip	9,542		(9,542)			(9,542)
2420618	Accrued Payroll	559,533		(559,533)			(559,533)
2420623	Distr, Cust Ops & Reg Svcs ICP	514,018		(514,018)			(514,018)
2420624	Corp & Shrd Srv Incentive Plan	28,887		(28,887)			(28,887)
2420635	Generation Incentive Plan	1		(1)			(1)
2420643	Accrued Audit Fees	76,160		(76,160)			(76,160)
2420656	Federal Mitigation Accru (NSR)	0		0			0
2420660	AEP Transmission ICP	12,705		(12,705)			(12,705)
2420700	Quality of Service	(0)		0			0
2420715	KY RPO Rider Liabilty	684		(684)			(684)
	Miscellaneous Current and Accrued Liab	5,453,204		(5,453,204)	0		(5,453,204)
	Other Current and Accrued Liabilities	10,553,622		(10,553,622)	0		(10,553,622)
	Current Liabilities	286,609,049	85,199,814	(201,409,236)	(38,458,193)		(162,951,042)
2811001	Acc Dfd FIT - Accel Amort Prop*	38,204,479		(38,204,479)	(38,204,479)	*	0
2814001	Acc Dfd FIT - FAS 109 Excess	(15,241,313)		15,241,313			15,241,313
2821001	Accum Defd FIT - Utility Prop*	323,519,396		(323,519,396)	(323,519,396)		0
2823001	Acc Dfrd FIT FAS 109 Flow Thru	34,657,873		(34,657,873)			(34,657,873)
2824001	Acc Dfrd FIT - SFAS 109 Excess	(70,375,240)		70,375,240			70,375,240
2831001	Accum Deferred FIT - Other*	123,162,735		(123,162,735)	(123,162,735)	*	0
2831102	Acc Dfd SIT-WV Pollution Cntrl*	1,243,953		(1,243,953)	(1,243,953)	*	0
2832001	Accum Dfrd FIT - Oth Inc & Ded	0		(0)			(0)
2833001	Acc Dfd FIT FAS 109 Flow Thru	30,794,143		(30,794,143)			(30,794,143)
2833002	Acc Dfrd SIT FAS 109 Flow Thru	102,763,385		(102,763,385)			(102,763,385)
2834001	Acc Defd FIT - SFAS 109 Excess	818,875		(818,875)			(818,875)
	Deferred Income Taxes	569,548,287		(569,548,287)	**(486,130,563)**		(83,417,723)

***Differences in accumulated deferred federal income tax account balances are due to tax accounting preparation for filing purposes**

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2550001	Accum Deferred ITC - Federal	(0)	(0)	0		0
	Deferred Investment Tax Credits	(0)	(0)	0	0	0
2540011	Over Recovered Fuel Cost	0		0		0
	Over Recover of Fuel Cost	0		0		0
2540237	KY Steam Main O/U	1,135,347		(1,135,347)		(1,135,347)
2540047	Unreal Gain on Fwd Commitments	1,145,192		(1,145,192)		(1,145,192)
2540071	KY Enhanced Reliability Liab	0		0		0
2540105	Home Energy Assist Prgm - KPCO	(110,431)		110,431		110,431
2540125	OSS Margin Sharing	845,171		(845,171)		(845,171)
2540230	PJM trans enhancement reg liab	493,764		(493,764)		(493,764)
2543246	Capacity Charge Tariff OverRec	162,725		(162,725)		(162,725)
2543247	KY - DSM Over Recovery	229,332		(229,332)		(229,332)
	Other Regulatory Liability	3,901,098		(3,901,098)		(3,901,098)
2543001	SFAS109 Flow Thru Def FIT Liab	0		(0)		(0)
2544001	SFAS 109 Exces Deferred FIT	112,999,783		(112,999,783)		(112,999,783)
	FAS109 DFIT Reclass (Acct 254)	112,999,783		(112,999,783)	0	(112,999,783)
	Regulatory Liabilities	116,900,882		(116,900,882)	0	(116,900,882)
2520000	Customer Adv for Construction	101,503		(101,503)	(101,503)	0
	Customer Advances for Construction	101,503		(101,503)	**(101,503)**	0
2530000	Other Deferred Credits	0		0		0
2530004	Allowances	0		0		0
2530022	Customer Advance Receipts	2,308,679		(2,308,679)		(2,308,679)
2530044	Neigh Help Neig-Cust Donations	(15)		15		15
2530050	Deferred Rev -Pole Attachments	470,153		(470,153)	(470,153)	0
2530067	IPP - System Upgrade Credits	0		(0)		(0)
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	19,009		(19,009)		(19,009)
2530101	MACSS Unidentified EDI Cash	0		0		0
2530112	Other Deferred Credits-Curr	48,277		(48,277)		(48,277)
2530114	Federl Mitigation Deferal(NSR)	0		0		0
2530124	Contr In Aid of Constr Advance	750,317		(750,317)	(750,317)	0
2530137	Fbr Opt Lns-Sold-Defd Rev	0		0		0
2530177	Deferred Rev-Bonus Lease Curr	0		0		0
2530178	Deferred Rev-Bonus Lease NC	0		0		0
2530185	O\U Accounting of ExpensesT	4,735		(4,735)		(4,735)
2530188	Long Term Assoc AP	8,860,712		(8,860,712)		(8,860,712)
2530190	QUAL OF SVC PENALTIES - LT	72,870		(72,870)		(72,870)
	Other Deferred Credits	12,534,737		(12,534,737)		(11,314,268)
	Deferred Credits	12,636,241	0	(12,636,241)	(1,321,973)	(11,314,268)
	DEFERRED CREDITS & REGULATED LIABILITIES	699,085,409	(0)	(699,085,409)	(487,452,536)	(211,632,873)
	CAPITAL & LIABILITIES	**3,449,326,711**	**2,445,357,960**	**(1,003,968,751)**	**(525,910,729)**	**(478,058,021)**
	AFUDC in CWIP			0	(7,263,290.10)	7,263,290
		3,449,326,711	2,445,357,960	(1,003,968,751)	(533,174,019)	(470,794,731)
	Assets	3,449,326,712	0	3,449,326,712	2,598,382,356	850,944,355
	Liabilities	3,449,326,711	2,445,357,960	(1,003,968,751)	(533,174,019)	(470,794,731)
		0	2,445,357,960	2,445,357,961	2,065,208,337	380,149,624

Account	Description
1010001	Plant in Service
1010008	Cloud Implement - PIS
1011001	Capital Leases
1011006	Prov-Leased Assets
1011012	Accrued Capital Leases
1011031	Operating Lease
1011032	Accrued Operating Leases
1011036	Prov - Operating Lease Assets
1050001	Held For Fut Use
1060001	Const Not Classifd
1060007	Cloud Implement - CCNC
1070000	Construction Work In Progress
1070001	CWIP - Project
1070007	Cloud Implementation Costs
1080001	A/P for Deprec of Plt
1080005	RWIP - Project Detail
1080011	Cost of Removal Reserve
1080013	ARO Removal Deprec - Accretion
1080026	Cloud Compute Implement Costs
1110001	A/P for Amort of Plt
1110007	Cloud Implement - A/P Amrt Plt
1210001	Nonutility Property - Owned
1220001	Depr&Amrt of Nonutl Prop-Ownd
1220003	Depr&Amrt of Nonutl Prop-WIP
1240027	Other Property - RWIP
1240028	Other Property - RETIRE
1240029	Other Property - CPR
1240092	Fbr Opt Lns-In Kind Sv-Invest
1290001	Non-UMWA PRW Funded Position
1290002	SFAS 106 - Non-UMWA PRW
1310000	Cash
1340018	Spec Deposits - Elect Trading
1340048	Spec Deposits-Trading Contra
1340051	Spec Depost RBC
1340053	Deposits - Flexible Spending
1340057	Wells Fargo Securities, LLC
1420001	Customer A/R - Electric
1420014	Customer A/R-System Sales
1420019	Transmission Sales Receivable
1420022	Cust A/R - Factored
1420023	Cust A/R-System Sales - MLR
1420024	Cust A/R-Options & Swaps - MLR
1420027	Low Inc Energy Asst Pr (LIEAP)
1420028	Emergency LIEAP
1420033	Cooling Assistance Prg (COOL)
1420042	Cust A/R - Special Contracts
1420044	Customer A/R - Estimated
1420050	PJM AR Accrual
1420054	Accrued Power Brokers

1420058	Cust A/R-Contra-Home Warranty
1420059	AR PS Bill-Cust Home Warranty
1420060	PJM Trans Enhancement Refund
1420062	Emergency Rent Assist ERUAP
1420102	AR Peoplesoft Billing - Cust
1420103	AR Long-Term-Customer
1430022	2001 Employee Biweekly Pay Cnv
1430023	A/R PeopleSoft Billing System
1430081	Damage Recovery - Third Party
1430083	Damage Recovery Offset Demand
1430102	AR Peoplesoft Billing - Misc
1440002	Uncoll Accts-Other Receivables
1460001	A/R Assoc Co - InterUnit G/L
1460006	A/R Assoc Co - Intercompany
1460009	A/R Assoc Co - InterUnit A/P
1460011	A/R Assoc Co - Multi Pmts
1460025	Fleet - M4 - A/R
1510001	Fuel Stock - Coal
1510002	Fuel Stock - Oil
1510003	Fuel Stock - Gas
1510020	Fuel Stock Coal - Intransit
1520000	Fuel Stock Exp Undistributed
1540001	M&S - Regular
1540003	Material in Transit
1540004	M&S - Exempt Material
1540006	M&S - Lime and Limestone
1540012	Materials & Supplies - Urea
1540013	Transportation Inventory
1540016	MMS - Truck Stock
1540022	M&S-Lime & Limestone Intransit
1540023	M&S Inv - Urea In-Transit
1540033	Inventory Pending Inspection
1581000	SO2 Allowance Inventory
1581003	SO2 Allowance Inventory - Curr
1581004	NOx Allowance Inventory - Curr
1581009	CSAPR Current SO2 Inv
1581014	CSAPR Seas NOx Comp Inv - Curr
1630004	Strs Exp-T&D Satellite Storerm
1630019	Stores Exp - Big Sandy Plant
1630031	Stores Exp - T&D General
1630033	Stores Exp - All Busin Units
1630109	Strs Exp - ACCT-COUNT-ADJ
1630163	Maximo Invoice Variance Acct
1650001	Prepaid Insurance
1650005	Prepaid Employee Benefits
1650006	Other Prepayments
1650009	Prepaid Carry Cost-Factored AR
1650010	Prepaid Pension Benefits
165001123	Prepaid Sales Taxes
165001124	Prepaid Sales Taxes
165001125	Prepaid Sales Taxes
165001223	Prepaid Use Taxes
165001224	Prepaid Use Taxes
165001225	Prepaid Use Taxes
1650014	FAS 158 Qual Contra Asset

1650021	Prepaid Insurance - EIS
1650023	Prepaid Lease
1650035	PRW Without MED-D Benefits
1650037	FAS158 Contra-PRW Exclud Med-D
1650041	Prepaid Regulatory Fees
1720000	Rents Receivable
1730000	Accrued Utility Revenues
1730002	Acrd Utility Rev-Factored-Assc
1740035	Misc Current Assets - EIS
1740037	Misc Curr Asset, External Ins
1750001	Curr. Unreal Gains - NonAffil
1750002	Long-Term Unreal Gns - Non Aff
1810002	Unamort Debt Exp - Inst Pur Cn
1810003	Unamort Debt Exp Notes Payable
1810006	Unamort Debt Exp - Sr Unsec Nt
1823000	Other Regulatory Assets
1823007	SFAS 112 Postemployment Benef
1823009	DSM Incentives
1823010	Energy Efficiency Recovery
1823011	DSM Lost Revenues
1823012	DSM Program Costs
1823022	HRJ 765kV Post Service AFUDC
1823037	KY Steam Maint O/U
1823054	HRJ 765kV Depreciation Expense
1823063	Unrecovered Fuel Cost
1823077	Unreal Loss on Fwd Commitments
1823108	Reg Asset - Rate Case Expenses
1823165	REG ASSET FAS 158 QUAL PLAN
1823166	REG ASSET FAS 158 OPEB PLAN
1823167	REG Asset FAS 158 SERP Plan
1823196	OSS Margin Sharing
1823299	SFAS 106 Medicare Subsidy
1823301	SFAS 109 Flow Thru Defd FIT
1823302	SFAS 109 Flow Thru Defrd SIT
1823306	Net CCS FEED Study Costs
182332821	FERC Formula Rates Under Recvr
182332822	FERC Formula Rates Under Recvr
182332823	FERC Formula Rates Under Recvr
182332824	FERC Formula Rates Under Rec
182332825	FERC FR Under-Recovery
1823376	Cost of Removal-Big Sandy Coal
1823377	NBV - AROs Retired Plants
1823378	M&S - Retiring Plants
1823379	Unrecovered Plant - Big Sandy
1823380	Spent AROs - Big Sandy Coal
1823410	BS1OR Unrecognized Equity CC
1823411	BS1OR Under Recovery CC
1823429	Rockport Capacity Def-Eqty CC
1823430	Rockport Capacity CC Deferral
1823431	Rockport Capacity Deferral
1823515	IGCC Pre-Construction Costs
1823516	BS1OR Under Recovery
1823517	Big Sandy Recov O/U Balancing
1823518	BSDR Unit 2 O&M
1823520	Under Recovery-Environmental

1823536	CC-NERC Compl/Cyber Unrec Eqty
1823537	CC-NERC Compliance/Cyber Sec
1823538	Def Depr-NERC Compli/Cybersec
1823547	Def Depr-Big Sandy Unit 1 Gas
1823550	Def Prop Tax-Big Sandy U1 Gas
1823557	KY Under-recovered PPA Rider
1823571	GreenHat Settlement Reg Deferr
1823620	2020 KY Storm Deferral
1823623	2021 KY Storm deferral
1823655	NOLC Regulatory Asset
1823656	NOLC Reg Asset-Equity Carrying
1823685	KY ELG Deferral
1823698	2022 KY Major Storm Deferral
1823722	2023 KY Storm Deferral
1823727	KY Deferred Securitization Exp
1823741	Tariff DR CC Deferral
1823742	Tariff DR DeferredEquity CC
1823757	KY 2024 Storm Deferral
1823767	KY 2025 Storm Deferral
1830000	Prelimin Surv&Investgtn Chrgs
1840001	Bldg Servcs Oper Exp-Clearing
1840006	Telephone Expense - Clearing
1840029	Transp-Assigned Vehicles
1840031	Affil Transactions-Cash Clrng
1840057	Cell Phone/Pager - Clearing
1840063	Corporate Charge Card Clearing
1840066	PPE / Safety Equipment
1850000	Temporary Facilities
1860001	Allowances
1860002	Deferred Expenses
186000322	Deferred Property Taxes
186000323	Deferred Property Taxes
186000324	Deferred Property Taxes
1860005	Unidentified Cash Receipts
1860006	Constructive Marketing Program
1860007	Billings and Deferred Projects
1860015	Billings Paid Union Benefits
1860077	Agency Fees - Factored A/R
186008124	Defd Property Tax - Cap Lease
186008125	Defd Property Tax - Cap Lease
1860092	Compatible Unit/Wrk 2k Sys Clr
1860153	Unamortized Credit Line Fees
1860160	Deferred Expenses - Current
1860166	Def Lease Assets - Non Taxable
1860185	Long Term Assoc AR
1860192	Trnsrce OU Acctg for Def Asset
1860332	Prov Opr Lease Assets-Gen&Misc
1890004	Loss Rec Debt-Debentures
1901001	Accum Deferred FIT - Other
1901002	Accum Deferred SIT - Other
1902001	Accum Defd FIT - Oth Inc & Ded
1903001	Acc Dfd FIT - FAS109 Flow Thru
1904001	Accum Dfd FIT - FAS 109 Excess
2010001	Common Stock Issued-Affiliated
2080000	Donations Recvd from Stckhldrs

2110000	Miscellaneous Paid-In Capital
2110018	DSIT Apportionment Adj.
2160001	Unapprp Retnd Erngs-Unrstrictd
2230000	Advances from Associated Co
2240002	Installment Purchase Contracts
2240005	Other Long Term Debt - Other
2240006	Senior Unsecured Notes
2240505	Oth LTD - Other - Current
2240506	Senior Unsecured Notes-Current
2260006	Unam Disc LTD-Dr-Sr Unsec Note
2270001	Obligatns Undr Cap Lse-Noncurr
2270003	Accrued Noncur Lease Oblig
2270031	Oblig undr Oper Lease-Non Curr
2270033	Acrued Noncur Oper Lease Oblig
2282003	Accm Prv I/D - Worker's Com
2282011	Accm Prv I/D - Asbestos - Curr
2282012	Accm Prv I/D - Asbestos
2283000	Accm Prv for Pensions&Benefits
2283002	Supplemental Savings Plan
2283005	SFAS 112 Postemployment Benef
2283006	SFAS 87 - Pensions
2283013	Incentive Comp Deferral Plan
2283015	FAS 158 SERP Payable Long Term
2283016	FAS 158 Qual Payable Long Term
2290002	Acc Prv Rate Refnds-Nonassoc
2300001	Asset Retirement Obligations
2300002	ARO - Current
2320001	Accounts Payable - Regular
2320002	Unvouchered Invoices
2320003	Retention
2320008	Miscellaneous Liabilities
2320011	Uninvoiced Fuel
2320052	Accounts Payable - Purch Power
2320053	Elect Trad-Options&Swaps
2320054	Emission Allowance Trading
2320073	A/P Misc Dedic. Power
2320076	Corporate Credit Card Liab
2320077	INDUS Unvouchered Liabilities
2320083	PJM Net AP Accrual
2320086	Accrued Broker - Power
2320094	Customer A/P - REC Activity
2320095	Home Warranty Payables
2320101	RTO AP Accrual for Cong Deriv
2330000	Corp Borrow Program (NP-Assoc)
2340001	A/P Assoc Co - InterUnit G/L
2340025	A/P Assoc Co - CM Bills
2340027	A/P Assoc Co - Intercompany
2340029	A/P Assoc Co - AEPSC Bills
2340030	A/P Assoc Co - InterUnit A/P
2340032	A/P Assoc Co - Multi Pmts
2340035	Fleet - M4 - A/P
2340037	A/P Assoc-Global Borrowing Int
2350001	Customer Deposits-Active
2350003	Deposits - Trading Activity
2360001	Federal Income Tax

2360002	State Income Taxes
236000215	State Income Taxes
236000216	State Income Taxes
236000217	State Income Taxes
236000218	State Income Taxes
236000219	State Income Taxes
236000220	State Income Taxes
236000221	State Income Taxes
236000222	State Income Taxes
236000223	State Income Taxes
2360003	Local Income Tax
236000319	Local Income Tax
2360004	FICA
2360005	Federal Unemployment Tax
2360006	State Unemployment Tax
236000718	State Sales and Use Taxes
236000722	State Sales and Use Taxes
236000723	State Sales and Use Taxes
236000724	State Sales and Use Taxes
236000725	State Sales and Use Taxes
236000821	Real Personal Property Taxes
236000822	Real Personal Property Taxes
236000823	Real Personal Property Taxes
236000824	Real Personal Property Taxes
236001217	State Franchise Taxes
236001218	State Franchise Taxes
236001219	State Franchise Taxes
236001220	State Franchise Taxes
236001321	State Business Occupatn Taxes
236001322	State Business Occupatn Taxes
236001323	State Business Occupatn Taxes
236001324	State Business Occupatn Taxes
236001325	State Business Occupatn Taxes
236001620	State Gross Receipts Tax
236001623	State Gross Receipts Tax
236001624	State Gross Receipts Tax
236001625	State Gross Receipts Tax
236001724	Municipal License Fees Accrd
236003322	Pers Prop Tax-Cap Leases
236003323	Pers Prop Tax-Cap Leases
236003324	Pers Prop Tax-Cap Leases
236003325	Pers Prop Tax-Cap Leases
236003523	Real Prop Tax-Cap Leases
236003524	Real Prop Tax-Cap Leases
236003525	Real Prop Tax-Cap Leases
2360037	FICA - Incentive accrual
2360038	Reorg Payroll Tax Accrual
2370002	Interest Accrued-Inst Pur Con
2370005	Interest Accrd-Other LT Debt
2370006	Interest Accrd-Sen Unsec Notes
2370007	Interest Accrd-Customer Depsts
2370018	Accrued Margin Interest
2410001	Federal Income Tax Withheld
2410003	Local Income Tax Withheld
2410004	State Sales Tax Collected

2410005	FICA Tax Withheld
2410008	Franchise Fee Collected
2410009	KY Utility Gr Receipts Lic Tax
2420000	Misc Current & Accrued Liab
2420001	P/R Ded - Charitable Contribut
2420002	P/R Ded - Medical Insurance
2420003	P/R Ded - Dental Insurance
2420013	P/R Ded - LTD Ins Premiums
2420021	Vacation Pay - Next Year
2420027	FAS 112 CURRENT LIAB
2420046	FAS 158 SERP Payable - Current
2420051	Non-Productive Payroll
2420071	P/R Ded - Vision Plan
2420072	P/R - Payroll Adjustment
2420076	P/R Savings Plan - Incentive
2420083	Active Med and Dental IBNR
2420088	Econ. Development Fund Curr
2420504	Accrued Lease Expense
2420511	Control Cash Disburse Account
2420512	Unclaimed Funds
2420514	Revenue Refunds Accrued
2420515	Severance Accrual
2420532	Adm Liab-Cur-S/Ins-W/C
2420542	Acc Cash Franchise Req
2420558	Admitted Liab NC-Self/Ins-W/C
242059224	Sales Use Tax - Leased Equip
242059225	Sales Use Tax - Leased Equip
2420618	Accrued Payroll
2420623	Distr, Cust Ops & Reg Svcs ICP
2420624	Corp & Shrd Srv Incentive Plan
2420635	Generation Incentive Plan
2420643	Accrued Audit Fees
2420656	Federal Mitigation Accru (NSR)
2420660	AEP Transmission ICP
2420700	Quality of Service
2420715	KY RPO Rider Liabilty
2430001	Oblig Under Cap Leases - Curr
2430003	Accrued Cur Lease Oblig
2430031	Oblig undr Oper Lease -Current
2430033	Acrued Curent Oper Lease Oblig
2440001	Curr. Unreal Losses - NonAffil
2440002	LT Unreal Losses - Non Affil
2440021	S/T Liability MTM Collateral
2440022	L/T Liability MTM Collateral
2520000	Customer Adv for Construction
2530022	Customer Advance Receipts
2530044	Neigh Help Neig-Cust Donations
2530050	Deferred Rev -Pole Attachments
2530067	IPP - System Upgrade Credits
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns
2530101	MACSS Unidentified EDI Cash
2530112	Other Deferred Credits-Curr
2530124	Contr In Aid of Constr Advance
2530137	Fbr Opt Lns-Sold-Defd Rev
2530175	Legal Contingencies

2530177	Deferred Rev-Bonus Lease Curr
2530185	O\U Accounting of ExpensesT
2530188	Long Term Assoc AP
2530190	QUAL OF SVC PENALTIES - LT
2540047	Unreal Gain on Fwd Commitments
2540071	KY Enhanced Reliability Liab
2540105	Home Energy Assist Prgm - KPCO
2540125	OSS Margin Sharing
2540230	PJM trans enhancement reg liab
2540237	KY Steam Main O/U
2543001	SFAS109 Flow Thru Def FIT Liab
2543246	Capacity Charge Tariff OverRec
2543247	KY - DSM Over Recovery
2543557	KY Over-recovered PPA Rider
2544001	SFAS 109 Exces Deferred FIT
2550001	Accum Deferred ITC - Federal
2811001	Acc Dfd FIT - Accel Amort Prop
2814001	Acc Dfd FIT - FAS 109 Excess
2821001	Accum Defd FIT - Utility Prop
2823001	Acc Dfrd FIT FAS 109 Flow Thru
2824001	Acc Dfrd FIT - SFAS 109 Excess
2831001	Accum Deferred FIT - Other
2831102	Acc Dfd SIT-WV Pollution Cntrl
2832001	Accum Dfrd FIT - Oth Inc & Ded
2833001	Acc Dfd FIT FAS 109 Flow Thru
2833002	Acc Dfrd SIT FAS 109 Flow Thru
2834001	Acc Defd FIT - SFAS 109 Excess
4030001	Depreciation Exp
4030029	Over/Undr Depr Exp Var Riders
4030046	Capitalized Software Depr Exp
4030047	Depr Exp - Cloud Computing
4031001	Depr - Asset Retirement Oblig
4040001	Amort. of Plant
4040007	Cloud Implement - Amort Plant
4060001	Amort of Plt Acq Adj
4073000	Regulatory Debits
4073014	Regulatory Debit - BSDR
4074000	Regulatory Credits
4074025	PPA RIDER Over/Under
4081002	FICA
4081003	Federal Unemployment Tax
408100519	Real Personal Property Taxes
408100520	Real Personal Property Taxes
408100521	Real Personal Property Taxes
408100522	Real Personal Property Taxes
408100523	Real Personal Property Taxes
408100524	Real Personal Property Taxes
408100622	State Gross Receipts Tax
408100623	State Gross Receipts Tax
408100624	State Gross Receipts Tax
408100625	State Gross Receipts Tax
4081007	State Unemployment Tax
408100818	State Franchise Taxes
408101422	Federal Excise Taxes
408101423	Federal Excise Taxes

408101424	Federal Excise Taxes
408101425	Federal Excise Taxes
408101719	St Lic-Rgstrtion Tax-Fees
408101722	St Lic-Rgstrtion Tax-Fees
408101922	State Sales and Use Taxes
408101923	State Sales and Use Taxes
408101924	State Sales and Use Taxes
408101925	State Sales and Use Taxes
408102021	State Business Occup Taxes
408102022	State Business Occup Taxes
408102023	State Business Occup Taxes
408102024	State Business Occup Taxes
408102025	State Business Occup Taxes
408102219	Municipal License Fees
408102220	Municipal License Fees
408102222	Municipal License Fees
408102223	Municipal License Fees
408102920	Real-Pers Prop Tax-Cap Leases
408102921	Real-Pers Prop Tax-Cap Leases
408102922	Real-Pers Prop Tax-Cap Leases
408102923	Real-Pers Prop Tax-Cap Leases
408102924	Real-Pers Prop Tax-Cap Leases
408102925	Real-Pers Prop Tax-Cap Leases
4081033	Fringe Benefit Loading - FICA
4081034	Fringe Benefit Loading - FUT
4081035	Fringe Benefit Loading - SUT
408103622	Real Prop Tax-Cap Leases
408103623	Real Prop Tax-Cap Leases
408103624	Real Prop Tax-Cap Leases
408103625	Real Prop Tax-Cap Leases
408200522	Real Personal Property Taxes
408200523	Real Personal Property Taxes
408200524	Real Personal Property Taxes
4091001	Income Taxes, UOI - Federal
4091002	Income Taxes, UOI - State
409100223	Income Taxes UOI - State
4092001	Inc Tax, Oth Inc&Ded-Federal
4092002	Inc Tax, Oth Inc & Ded - State
409200223	Inc Tax Oth Inc Ded - State
4101001	Prov Def I/T Util Op Inc-Fed
4101002	Prov Def I/T Util Op Inc-State
4102001	Prov Def I/T Oth I&D - Federal
4102002	Prov Def I/T Oth I&D - State
4111001	Prv Def I/T-Cr Util Op Inc-Fed
4111002	Prv Def I/T-Cr UtilOpInc-State
4111005	Accretion Expense
4112001	Prv Def I/T-Cr Oth I&D-Fed
4116000	Gain From Disposition of Plant
4118002	Comp. Allow Gains Title IV SO2
4118003	Comp. Allow. Gains-Seas NOx
4170004	Rev from Non-Util Oper NonAfil
4171006	Outside Services - Other
4171009	Office Supplies & Expense
4180001	Non-Operatng Rental Income
4180005	Non-Opratng Rntal Inc-Depr

4190002	Int & Dividend Inc - Nonassoc
4190005	Interest Income - Assoc CBP
4191000	Allw Oth Fnds Usd Drng Cnstr
4210001	Misc Non-Operating Inc-Assoc
4210002	Misc Non-Op Inc-NonAsc-Rents
4210007	Misc Non-Op Inc - NonAsc - Oth
4210009	Misc Non-Op Exp - NonAssoc
4211000	Gain on Dspsition of Property
4212000	Loss on Dspsition of Property
4261000	Donations
4263001	Penalties
4263003	Penalties - Quality of Service
4264000	Civic and Political Activity
4264001	Non-deduct Lobbying per IRS
4265002	Other Deductions - Nonassoc
4265004	Social & Service Club Dues
4265007	Regulatory Expenses
4265009	Factored Cust A/R Exp - Affil
4265010	Fact Cust A/R-Bad Debts-Affil
4265033	Transition Costs
4270002	Int on LTD - Install Pur Contr
4270005	Int on LTD - Other LTD
4270006	Int on LTD - Sen Unsec Notes
4280002	Amrtz Debt Dscnt&Exp-Instl Pur
4280003	Amrtz Debt Dscnt&Exp-N/P
4280006	Amrtz Dscnt&Exp-Sn Unsec Note
4281004	Amrtz Loss Rcquired Debt-Dbnt
4300001	Interest Exp - Assoc Non-CBP
4300003	Int to Assoc Co - CBP
4310001	Other Interest Expense
4310002	Interest on Customer Deposits
4310007	Lines Of Credit
4320000	Allw Brrwed Fnds Used Cnstr-Cr
4400001	Residential Sales-W/Space Htg
4400002	Residential Sales-W/O Space Ht
4400005	Residential Fuel Rev
4420001	Commercial Sales
4420002	Industrial Sales (Excl Mines)
4420004	Ind Sales-NonAffil(Incl Mines)
4420006	Sales to Pub Auth - Schools
4420007	Sales to Pub Auth - Ex Schools
4420013	Commercial Fuel Rev
4420016	Industrial Fuel Rev
4440000	Public Street/Highway Lighting
4440002	Public St & Hwy Light Fuel Rev
4470006	Sales for Resale-Bookout Sales
4470010	Sales for Resale-Bookout Purch
4470027	Whsal/Muni/Pb Ath Fuel Rev
4470033	Whsal/Muni/Pub Auth Base Rev
4470074	Sale for Resale-Aff-Trnf Price
4470082	Financial Electric Realized
4470089	PJM Energy Sales Margin
4470098	PJM Oper.Reserve Rev-OSS
4470099	Capacity Cr. Net Sales
4470100	PJM FTR Revenue-OSS

4470103	PJM Energy Sales Cost
4470110	PJM TO Admin. Exp.-NonAff.
4470115	PJM Meter Corrections-OSS
4470116	PJM Meter Corrections-LSE
4470126	PJM Incremental Imp Cong-OSS
4470131	Non-Trading Bookout Purch-OSS
4470150	Transm. Rev.-Dedic. Whlsl/Muni
4470151	Trading Auction Sales Affil
4470175	OSS Sharing Reclass - Retail
4470176	OSS Sharing Reclass-Reduction
4470206	PJM Trans loss credits-OSS
4470209	PJM transm loss charges-OSS
4470215	PJM 30m Suppl Reserve CH OSS
4470220	PJM Regulation - OSS
4470221	PJM Spinning Reserve - OSS
4491002	Non-Tran Prov Rate Ref Whlsale
4491003	Non-Tran Prov Rate Ref Retail
4491004	Prov Rate Refund - Affiliated
4491005	Tran Prov Trans Ref NonAffil
4491006	Tran Prov Trans Ref Frml Rate
4491007	Trans Prov Trans Refunds Affil
4500000	Forfeited Discounts
4510001	Misc Service Rev - Nonaffil
4540001	Rent From Elect Property - Af
4540002	Rent From Elect Property-NAC
4540004	Rent From Elect Prop-ABD-Nonaf
4540005	Rent from Elec Prop-Pole Attch
4560007	Oth Elect Rev - DSM Program
4560012	Oth Elect Rev - Nonaffiliated
4560015	Other Electric Revenues - ABD
4560043	Oth Elec Rv-Trn-Aff-Trnf Price
4561005	PJM Point to Point Trans Svc
4561006	PJM Trans Owner Admin Rev
4561007	PJM Network Integ Trans Svc
4561019	Oth Elec Rev Trans Non Affil
4561028	PJM Pow Fac Cre Rev Whsl Cu-NA
4561029	PJM NITS Revenue Whsl Cus-NAff
4561030	PJM TO Serv Rev Whls Cus-NAff
4561033	PJM NITS Revenue - Affiliated
4561034	PJM TO Adm. Serv Rev - Aff
4561035	PJM Affiliated Trans NITS Cost
4561036	PJM Affiliated Trans TO Cost
4561045	PJM Non-Aff Gen IPP Rev
4561058	NonAffil PJM Trans Enhncmt Rev
4561059	Affil PJM Trans Enhancmnt Rev
4561060	Affil PJM Trans Enhancmnt Cost
4561061	NAff PJM RTEP Rev for Whsl-FR
4561062	PROVISION RTO Tran Cost Affi
4561063	PROVISION RTO Tran Rev Aff
4561064	PROVISION RTO Tran Rv Frml Rts
4561065	PROVISION RTO Tran Rev NonAff
5000000	Oper Supervision & Engineering
5000005	Deferred OM - 20% Non FMR
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5010001	Fuel Consumed

5010003	Fuel - Procure Unload & Handle
5010005	Fuel - Deferred
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5010013	Fuel Survey Activity
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5010021	Transp Gas Consumed Steam
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5020002	Urea Expense
5020003	Trona Expense
5020004	Lime-Related Expenses
5020005	Polymer expense
5020020	Misc Consumable Exp
5050000	Electric Expenses
5060000	Misc Steam Power Expenses
5060002	Misc Steam Power Exp-Assoc
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5090001	Allowance Consumption - NOx
5090009	Allow Consumpt CSAPR SO2
5100000	Maint Supv & Engineering
5110000	Maintenance of Structures
5120000	Maintenance of Boiler Plant
5120025	Maint of Blr Plt Environmental
5120034	BSDR O/U Recovery - Maint Cost
5120037	KY Steam Maint O/U
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5132000	Maint of Computer Software-Mjr
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5140025	Maint MiscStmPlt Environmental
5312000	Maint of Computer Software
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5550023	Purch Power Capacity -NA
5550027	Purch Pwr-Non-Fuel Portion-Aff
5550029	Purch Power-Assoc-Trnsfr Price
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5550075	PJM Reactive-Credit
5550076	PJM Black Start-Charge
5550078	PJM Regulation-Charge
5550079	PJM Regulation-Credit
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5550083	PJM Sync & Non Sync-Charge
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5570000	Other Expenses
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5581300	Oper Supervision & Engineering
5581400	Wind Turb Gen&Oth Plnt Op-Mjr
5581900	Maint Wind Turb Struct&Eq-Mjr
5582000	Solar Panel Gen&Oth Plt Op-Mjr
5587000	Maint Solar Pnl Strct & Eq-Mjr
5600000	Oper Supervision & Engineering
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5690000	Maintenance of Structures
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5692000	Maint of Computer Software
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5700000	Maint of Station Equipment
5710000	Maintenance of Overhead Lines

5720000	Maint of Underground Lines
5730000	Maint of Misc Trnsmssion Plt
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5800000	Oper Supervision & Engineering
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5820000	Station Expenses
5830000	Overhead Line Expenses
5840000	Underground Line Expenses
5850000	Street Lighting & Signal Sys E
5860000	Meter Expenses
5870000	Customer Installations Exp
5880000	Miscellaneous Distribution Exp
5890001	Rents - Nonassociated
5890002	Rents - Associated
5900000	Maint Supv & Engineering
5910000	Maintenance of Structures
5920000	Maint of Station Equipment
5923000	Maint of Computer Software-Mjr
5924000	Maint of Comm Equipmt-Mjr
5930000	Maintenance of Overhead Lines
5930001	Tree and Brush Control
5930010	Storm Expense Amortization
5940000	Maint of Underground Lines
5950000	Maint of Lne Trnf,Rglators&Dvi
5960000	Maint of Strt Lghtng & Sgnal S
5970000	Maintenance of Meters
5980000	Maint of Misc Distribution Plt
8140000	Underground Storage Expenses
9010000	Supervision - Customer Accts
9020000	Meter Reading Expenses
9020002	Meter Reading - Regular
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9090000	Information & Instruct Advrtis
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9210023	EMP TRAVEL-MILEAGE
9210024	EMP TRAVEL-PARKING
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9260055	IntercoFringeOffset- Don't Use
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9260060	Amort-Post Retirerment Benefit
9260062	Pension Plan - Non-Service
9260064	Def AEPSC Pension Settlement
9270000	Franchise Requirements
9280000	Regulatory Commission Exp
9280001	Regulatory Commission Exp-Adm
9280002	Regulatory Commission Exp-Case
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9301000	General Advertising Expenses
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9301003	TV Station Advertising Time
9301006	Spec Corporate Comm Info Proj
9301007	Special Adv Space & Prod Exp
9301010	Publicity
9301012	Public Opinion Surveys
9301014	Video Communications
9301015	Other Corporate Comm Exp
9302000	Misc General Expenses
9302003	Corporate & Fiscal Expenses
9302004	Research, Develop&Demonstr Exp
9302006	Assoc Bus Dev - Materials Sold
9302007	Assoc Business Development Exp
9310001	Rents - Real Property
9310002	Rents - Personal Property
9350000	Maintenance of General Plant
9350001	Maint of Structures - Owned
9350002	Maint of Structures - Leased
9350012	Maint of Data Equipment
9350013	Maint of Cmmncation Eq-Unall
9350015	Maint of Office Furniture & Eq
9350016	Maintenance of Video Equipment
9350019	Maint of Gen Plant-SCADA Equ
9350023	Site Communications Services
9350024	Maint of DA-AMI Comm Equip
9351000	Maint of Computer Hardware
9352000	Maint of Computer Software
9353000	Maint of Comm Equipmt

Report of Independent Auditors

To the Management and Board of Directors of Kentucky Power Company

Opinion

We have audited the accompanying financial statements of Kentucky Power Company (the "Company"), which comprise the balance sheets as of December 31, 2024 and 2023, and the related statements of income, of changes in common shareholder's equity and of cash flows for the years then ended, including the related notes (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date the financial statements are available to be issued.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures

PricewaterhouseCoopers LLP, 41 South High Street, Suite 2500, Columbus, Ohio 43215
T: (614) 225 8700, www.pwc.com/us

include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

PricewaterhouseCoopers LLP

Columbus, Ohio
February 13, 2025

American Electric Power
[illegible]

AEP
AMERICAN ELECTRIC POWER

November 17, 1997

Mr. Bryan K. Craig
Acting Director, Division of Electric
and Hydropower Operations
Office of the Chief Accountant
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Peter J. DeMaria
Executive Vice President
Administrative and
Chief Accounting Officer
614 223 1901

Dear Mr. Craig:

We have reviewed the audit report (copy attached) forwarded to us on October 30, 1997. The report summarizes the Results of the FERC audit staff's examination of the Books and Records of Kentucky Power Company for the period January 1, 1992 through December 31, 1996 in Docket No. FA96-40-000 and FA96-40-001.

Our comments on the three report issues are noted herein. Should you have any questions concerning our comments, please do not hesitate to contact the undersigned or Leonard V. Assante, Controller of AEPSC.

I. Compliance Exceptions

1. Accounting for Settlement Costs

Kentucky Power's Response

We agree with the recommendation that settlement costs on employment litigation be recorded below the line and have revised our accounting procedures accordingly. Attached is a copy of July 9, 1997 memorandum from G. R. Knorr, Assistant Controller of AEPSC, revising our procedures.

2. Miscellaneous Accounting Misclassification

Kentucky Power's Response

We agree with the recommendation concerning Account 228.3 (Accumulated Provision for Pensions and Benefits) and have revised our accounting procedures accordingly. Attached is a copy of our August 13, 1997 memorandum from G. S. Campbell/H. E. McCoy revising our procedures.

II. Deferred Matter

1. Accounting Classification for Service Company Billings

Kentucky Power's Response

The FERC audit report makes no recommendation on this issue pending further study by the FERC's Office of the Chief Accountant. We reserve our right to respond to this issue when the FERC's study is completed and released for comment.

I would like to take this opportunity to express our support for the new centralized approach to auditing AEP's electric operating subsidiaries. The new approach reduced the total time required to complete the audit of all AEP subsidiaries and reduced the cost to both AEP and the FERC. I would also like to thank Lucretia Smith and the fine staff of auditors that performed an efficient audit while minimizing disruption of our accounting operations.

Respectfully submitted,

Peter J. DeMaria
PJD:bv
Attachments

RIMS

FEDERAL ENERGY REGULATORY COMMISSION

WASHINGTON, D.C. 20426

In Reply Refer To:
OCA-DE/HO
Docket Nos. FA96-40-000
and FA96-40-001

OCT 30 1997

Kentucky Power Company
Attention: Mr. Len Assante
Controller
1 Riverside Plaza
Columbus, OH 43215

Elec. Cor.

Ladies and Gentlemen:

The Division of Electric and Hydropower Operations of the Office of the Chief Accountant has examined the books and records of Kentucky Power Company for the period January 1, 1992, through December 31, 1996. The purpose of the examination was to evaluate your Company's compliance with Commission accounting and reporting regulations contained in the Uniform System of Accounts, Annual Report FERC Form No. 1, and the related regulations. The examination included selective tests of the accounting records, review of the internal control structure, and other tests and procedures considered necessary under the circumstances.

The Division of Electric and Hydropower Operations recommended corrective actions on certain findings of noncompliance with the Commission's accounting, financial reporting, and/or related regulations. Part I of the enclosed audit report describes the findings and recommendations. By letter dated August 29, 1997, your Company agreed to adopt the recommended corrective actions in Part I. I hereby approve and direct the recommended corrective actions in Part I.

The issue set forth in Part II on the accounting classification of service company billings is deferred for further study. The issue has been assigned as Docket No. FA96-40-001.

The Kentucky Power Commission did not respond with any objections to the foregoing matters.

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FERC - DOCKETED
OCT 30 1997

The Commission delegated authority to act in this matter to the Acting Director, Division of Electric and Hydropower Operations under 18 C.F.R. § 375.303. This letter order constitutes final agency action on the corrective actions approved and directed in this report. Within 30 days of the date of this order, your Company may file a request for rehearing by the Commission under 18 C.F.R. § 385.713.

This letter order is without prejudice to the Commission's right to require hereafter any later adjustments arising from additional information that may come to its attention.

Sincerely,

Bryan K. Craig

Bryan K. Craig
Acting Director,
Division of Electric
and Hydropower Operations

Enclosure

Results of the Examination

of the

Books and Records

of

Kentucky Power Company
Docket Nos. FA96-40-000
and FA96-40-001

For the Period

1/1/92 through 12/31/96

Conducted by

Division of Audits
Office of the Chief Accountant
Federal Energy Regulatory Commission

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Kentucky Power Company 1

I. Compliance Exceptions

Kentucky Power Company (the Company) agreed to the recommended corrective actions on the following compliance matters:

1. Accounting for Settlement Costs

The Company used the wrong accounts to record costs to settle employment suits.

Recommendation

We recommend the Company revise procedures to ensure it records settlement payments in Account 426.5, Other Deductions, consistent with the requirements of the Uniform System of Accounts.

Facts

During 1995 and 1996, the AEP Service Company paid certain employment settlement costs. It recorded the settlement fees of $47,500 in Work Order No. 9988 - AEPSC Overheads. The Service Company allocated this work order to all the AEP Service Company Work Orders based on salaries. The Service Company then billed out to the AEP System companies all its costs based upon SEC approved allocations for each individual work order. As a result, the Company recorded these settlement costs in every account charged as a result of the AEP Service Company billing. The effect of these transactions on the individual operating companies was not material.

Discussion of Accounting Requirements

Accounting Release No. 12, issued February 12, 1980, requires companies to charge expenditures resulting from compromise settlements or consent decrees to Account 426.5.

2. Miscellaneous Accounting Classification

The Company classified a transaction in the wrong account. The following indicates the nature of the item misclassified, the account the Company used, and the proper account for such transactions:

Kentucky Power Company 2

Description	Account Used	Proper Account
Post-Retirement Benefits Other than Pensions - Liability	228.4	228.3

Recommendation

We recommend the Company adopt procedures to ensure that it records similar charges in the future consistent with the requirements of the Uniform Systems of Accounts.

II. Deferred Matter

1. Accounting Classification for Service Company Billings

AEPSC is a subsidiary of American Electric Power Corporation (AEP). It provides various services to affiliated AEP subsidiaries, including system planning, engineering, financial, accounting, public affairs, fuel procurement and customer services.

AEPSC is subject to the Public Utility Holding Company Act (PUCHA) which the Securities and Exchange Commission (SEC) administers. AEPSC maintains its accounts based on the SEC's Uniform System of Accounts for mutual service companies.

AEPSC first assigns all costs to various expense and other accounts. Then, it assigns all direct and indirect costs to various billable projects or work orders. 1/ Direct costs include labor and labor fringes, such as payroll taxes and employee benefits. Indirect amounts include overhead amounts not specifically assignable to the work orders, such as administrative and general salaries, miscellaneous general expenses, depreciation, maintenance of general plant, etc.

AEPSC bills interest on working capital loans and income taxes to the various operating companies as separate items apart from the normal fully allocated billable work orders.

AEPSC's invoices rendered to the Company and the other AEP subsidiaries include a cost breakdown for each work order between direct and overhead costs. The subsidiaries use the accounting classifications AEPSC provides to assign costs to its various accounts. Under this procedure, the AEP subsidiaries classified certain AEPSC administrative and general expenses, payroll taxes, etc., to accounts other than those that it would charge if it directly incurred the expenditures. For example, charges for direct labor costs to particular projects and accounts included additional costs related to employment taxes, pensions, other employee benefits, administrative and general expenses, and depreciation and maintenance of the office building owned by AEPSC.

Also, the AEP subsidiaries recorded income taxes and interest costs separately billed by AEPSC in Account 930.2, Miscellaneous General Expenses.

1/ When AEPSC performs specific work for more than one company within the holding company group, it uses an SEC approved method for assigning the cost among the various members.

Discussion of Accounting Requirements

General Instruction No. 14, Transactions with Associated Companies, of the Uniform System of Accounts States:

> Each utility shall keep its accounts and records so as to be able to furnish accurately and expeditiously statements of all transactions with associated companies. The statements may be required to show the general nature of the transactions, the amounts involved therein and the amounts included in each account prescribed herein with respect to such transactions. **Transactions with associated companies shall be recorded in the appropriate accounts for transactions of the same nature.** Nothing herein contained, however, shall be construed as restraining the utility from subdividing accounts for the purpose of recording separately transactions with associated companies. [Emphasis added.]

The Office of the Chief Accountant is currently studying the issue of classification of affiliated company charges on an industry-wide basis. Therefore, the Division of Audits did not make any recommendations on the subject pending completion of the study and any resulting FERC action. The accounting for the classification of affiliated company charges will be resolved in a separate docket, Docket No. FA96-40-001.

Date July 9, 1997

Subject Employment Settlement Costs

From G. R. Knorr

To File

Accounting Release 12 (AR-12) issued by the Office of the Chief Accountant at FERC requires all expenditures related to discriminatory employment practices to be recorded below-the-line as other income deductions. Fines and penalties are to be recorded in Account 426.3, Penalties, and all other costs, including settlement costs paid to the plaintiffs, are to be recorded in Account 426.5, Other deductions.

In the future, whenever such costs are paid by AEP Service Corporation, the expenditures should be classified to the appropriate FERC account (see above) and to Work Order No. 1011, Miscellaneous non-operating expenses. Work Order No. 1011 will transfer the incurred costs to first-tier AEP client companies for recording below-the-line.

G. R. Knorr

cc P. J. DeMaria
L. V. Assante
T. P. Bowman - Canton
G. E. Laurey
F. L. Sagan

AMERICAN ELECTRIC POWER

Date August 13, 1997

Subject **Reclassification of Benefits Liabilities**

From Greg Campbell/Hugh McCoy

To
Tim Bowman - Canton
Jerry Knorr - Columbus
George Lauer - Columbus
Maurice McIntyre - Ft. Wayne
Tom Mitchell - Roanoke

Our practice in accounting for accumulated liabilities for pension benefits recorded under SFAS 87, postretirement benefits (OPEB) recorded under SFAS 106, and postemployment benefits recorded under SFAS 112 has been to record the liabilities to Account 228.4, Accumulated Miscellaneous Operating Provisions. We did not use Account 228.3, Accumulated Provision for Pensions and Benefits, because the description of Account 228.3 seems to exclude benefits funded through an irrevocable trust fund.

Nevertheless, during the course of the recent FERC audit, the FERC Staff informed us that our OPEB liability should be recorded to Account 228.3, rather than 228.4. The Staff also referred us to the FERC's May 7, 1993 OPEB accounting guidance in Docket No. AI93-4-000, which also provides for the use of Account 228.3. Therefore, the accumulated liability for benefits recorded under SFAS 87, 106, and 112 as of July 31, 1997 that is currently recorded in Account 228.4 should be reclassified in August 1997 business to Account 228.3, Accumulated Provision for Pensions and Benefits.

Please contact us if you should have any questions on this matter.

Hugh McCoy

Greg Campbell/Hugh McCoy

cc: Len Assante
Geoff Dean
Pete DeMaria
Bill Scott
Deloitte & Touche

themfrac-mdfilab-rec

Intra-System

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: 2024/ Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

IV. When to Submit

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

obtained and give date of the authorization.

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

EXCERPTS FROM THE LAW

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

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

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

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

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

"Sec. 304.

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

"Sec. 309.

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

GENERAL PENALTIES

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/ Period of Report
Kentucky Power Company	End of: 2024/ Q4

03 Previous Name and Date of Change (If name changed during year)
/

04 Address of Principal Office at End of Period (Street, City, State, Zip Code)
1 Riverside Plaza, Columbus, OH 43215-2373

05 Name of Contact Person	06 Title of Contact Person
Jason M. Johnson	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	09 This Report is An Original / A Resubmission	10 Date of Report (Mo, Da, Yr)
614- 716-1000	(1) ☑ An Original (2) ☐ A Resubmission	04/08/2025

Annual Corporate Officer Certification

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed (Mo, Da, Yr)
Jeffrey W Hoersdig	Jeffrey W Hoersdig	04/08/2025
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: 04/08/2025	Year/Period of Report End of: 2024/ Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	NA
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	NA
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	NA
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	NA
22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	NA
25	Unrecovered Plant and Regulatory Study Costs	230b	NA
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	NA
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	NA
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
47	**Purchased Power**	326	
48	**Transmission of Electricity for Others**	328	
49	**Transmission of Electricity by ISO/RTOs**	331	NA
50	**Transmission of Electricity by Others**	332	
51	**Miscellaneous General Expenses-Electric**	335	
52	**Depreciation and Amortization of Electric Plant (Account 403, 404, 405)**	336	
53	**Regulatory Commission Expenses**	350	
54	**Research, Development and Demonstration Activities**	352	
55	**Distribution of Salaries and Wages**	354	
56	**Common Utility Plant and Expenses**	356	NA
57	**Amounts included in ISO/RTO Settlement Statements**	397	
58	**Purchase and Sale of Ancillary Services**	398	
59	**Monthly Transmission System Peak Load**	400	
60	**Monthly ISO/RTO Transmission System Peak Load**	400a	NA
61	**Electric Energy Account**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	
64	**Hydroelectric Generating Plant Statistics**	406	NA
65	**Pumped Storage Generating Plant Statistics**	408	NA
66	**Generating Plant Statistics Pages**	410	NA
66.1	**Energy Storage Operations (Large Plants)**	414	NA
66.2	**Energy Storage Operations (Small Plants)**	419	NA
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☐ No annual report to stockholders is prepared		

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

GENERAL INFORMATION

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

Jeffrey W. Hoersdig, Assistant Controller

1 Riverside Plaza Columbus, OH 43215-2373

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

Kentucky - July 21,1919

State of Incorporation:

Date of Incorporation:

Incorporated Under Special Law:

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

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

(b) Date Receiver took Possession of Respondent Property:

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

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

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

Electric - Kentucky

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

☐ Yes

(2)

☑ No

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

CONTROL OVER RESPONDENT

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

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

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

CORPORATIONS CONTROLLED BY RESPONDENT

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

Definitions

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

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

OFFICERS

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

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

Page 104

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

FOOTNOTE DATA

(a) Concept: OfficerTitle

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

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

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)(2)	Stock Awards ($)(3)	Non-Equity Incentive Plan Compensation ($)(4)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(5)	All Other Compensation ($)(6)	Total ($)
William J. Fehrman								
President and Chief Executive Officer	2024	$ 628,846	$ 2,000,000	$ 9,469,144	$ 1,100,000	$ —	$ 59,032	$ 13,257,022
Charles E. Zebula								
Executive Vice President and Chief Financial Officer	2024	$ 724,327	$ —	$ 2,250,000	$ 605,840	$ 177,002	$ 85,564	$ 3,842,733
Greg B. Hall								
Executive Vice President and Chief Commercial Officer	2024	$ 575,491	$ —	$ 2,600,000	$ 485,416	$ 167,640	$ 70,977	$ 3,899,524
David M. Feinberg								
Executive Vice President, General Counsel and Secretary	2024	$ 771,628	$ —	$ 1,827,648	$ 447,448	$ 132,958	$ 77,057	$ 3,256,739
Therace M. Risch								
Executive Vice President, Chief Information and Technology Officer	2024	$ 684,906	$ —	$ 1,607,665	$ 536,999	$ 61,118	$ 35,400	$ 2,926,088
Ben Fowke								
Former Interim President and Chief Executive Officer	2024	$ 1,058,462	$ —	$ 8,060,780	$ 2,000,000	$ —	$ 210,777	$ 11,330,019
Julia A. Sloat								
Former Chair of the Board, President and Chief Executive Officer	2024	$ 327,692	$ —	$ —	$ —	$140,257	$ 2,454,334	$ 2,922,283

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

21.The amount in the bonus column for Mr. Fehrman reflects a negotiated hire bonus to be paid in 2024 following his hire as President and Chief Executive Officer on August 1.
3.The amounts reported in this column reflect the aggregate grant date fair value calculated in accordance with FASB ASC Topic 718 of the performance shares, restricted stock units (RSUs) and unrestricted shares granted under our Long-Term Incentive Plan. See Note 15 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2024 for a discussion of the relevant assumptions used in calculating these amounts. The number of shares realized and the value of the performance shares, if any, will depend on the Company's performance during a 3-year performance period. The potential payout can range from 0 percent to 200 percent of the target number of performance shares, plus any dividend equivalents. The value of the performance shares will be based on three measures: a Board approved cumulative operating earnings per share measure (Cumulative EPS 50%), a total shareholder return relative to peer companies (Relative TSR 40%) and a measure of generation capacity additions that maintain reliability through the clean energy transition (Maintaining Reliability 10%). The grant date fair value of the performance shares that are based on Cumulative EPS was computed in accordance with FASB ASC Topic 718 and was measured based on the closing price of AEP's common stock on the grant date. The maximum amount payable for the 2024 performance shares that are based on Cumulative EPS measured on the grant date is $3,500,000 for Mr. Fehrman, 825,000 for Mr. Hall, 1,237,500 for Mr. Feinberg, and $750,000 for Ms. Risch. The maximum amount payable for the 2024 performance shares that are based on Maintaining Reliability is $700,000 for Mr. Fehrman, $165,000 for Mr. Hall, $247,500 for Mr. Feinberg, and $150,000 for Ms. Risch. The grant date fair value of the 2024 performance shares that are based on Relative TSR is calculated using a Monte-Carlo model as of the date of grant, in accordance with FASB ASC Topic 718. Because the performance shares that are based on Relative TSR are subject to market conditions as defined under FASB ASC Topic 718, they did not have a maximum value on the grant date that differed from the grant date fair values presented in the table. Instead, the maximum value is factored into the calculation of the grant date fair value. The values realized from the 2022-2024 performance shares are included in the Option Exercises and Stock Vested for 2024 table.

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

5.The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and non-qualified defined benefit pension plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. See the Pension Benefits for 2024 table and related footnotes for additional information. See Note 8 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2024 for a discussion of the relevant assumptions. None of the named executive officers received preferential or above-market earnings on deferred compensation.

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

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

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

Perquisites provided in 2024 included: financial counseling and tax preparation services and, for Board members (Mr. Fehrman, Mr. Fowke and Ms. Sloat) an allocated share of a group premium for directors' travel accident insurance. Executive officers may also have the occasional personal use of event tickets when such tickets are not being used for business purposes, however, there is no associated incremental cost. From time to time, executive officers may receive customary gifts from third parties that sponsor events (subject to our policies on conflicts of interest).

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

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

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

DIRECTORS

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

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

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

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ Yes ☐ No

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

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

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

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

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

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

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20241031-5410	10/31/2024	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
2	20240528-5349	05/28/2024	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14

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

INFORMATION ON FORMULA RATES - Formula Rate Variances

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

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1	204-207	Electric Plant in Service	g	49
2	214	Electric Plant Held for Future Use	d	46
3	216	Construction Work in Progress	b	1
4	219	Accumulated Depreciation	b	21
5	310-311	Sales for Resale	k	1
6	320	Electric Operations & Maintenance Expense	b	5
7	320	Electric Operations & Maintenance Expense	b	25
8	320	Electric Operations & Maintenance Expense	b	31
9	321	Electric Operations & Maintenance Expense	b	93
10	323	Electric Operations & Maintenance Expense	b	185
11	336	Depreciation Expense	b	7
12	354	Distribution of Wages and Salaries	b	28

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

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

None

None

None

None

None

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

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

None

12. Not Used

13. Benjamin G S Fowke III, elected as Director, Chief Executive Officer and Chair of the Board effective on 02-26-2024.

Daniel E Mueller, elected as Vice President-Tax effective on 01-27-2024.

David P. Hoffman, elected as Vice President - General Assets effective on 01-20-2024.

Noah K Hollis, elected as Assistant Treasurer effective on 03-30-2024.
William J. Fehrman, elected as Chair of the Board, Chief Executive Officer and Director effective on 08/1/2024

Benjamin Fowke III, elected as Senior Advisor effective on 08/1/2024 and also resigned as Chair

of the Board, Chief Executive Officer effective on 07/31/2024 and also as Director on 08/26/2024.

Michele Ross, elected as Vice President - Distribution Region Operations effective on 08/03/2024.

Jeffrey D. Newcomb, elected as Vice President - Regulatory & Finance effective on 08/19/2024.

Matthew D Fransen, elected as Vice President and Treasurer effective on 12/01/2024.

Julia A Sloat, resigned as Director, Chair of the Board, Chief Executive Officer effective on 02-25-2024.

Daniel E Mueller, resigned as Assistant Vice President - Tax on 01-26-2024.

James X Llende, resigned as Vice President-Tax on 01-25-2024.

Renee V Hawkins, resigned as Assistant Treasurer effective on 05/03/2024.

Everett G. Phillips, resigned as Vice President - Distribution Region Operations effective on 07/01/2024.

Brian K. West, resigned as Vice President - Regulatory & Finance effective on 07/01/2024.

Therace M. Risch, resigned as Director effective on 09/23/2024.

Peggy I. Simmons, resigned as Director effective on 09/23/2024.

Christian T. Beam, resigned as Director effective on 09/23/2024.

Phillip R. Ulrich, resigned as Director effective on 09/23/2024.

Antonio P. Smyth, resigned as Director effective on 09/23/2024.

David P. Hoffman, resigned as Vice President - Generation Assets effective on 07/01/2024.

Benjamin Fowke III resigned as Senior Advisor effective on 10/22/2024.

Peggy I Simmons resigned as Vice President effective on 10/31/2024.

Julie A Sherwood resigned as Vice President and Treasurer effective on 11/30/2024.

Proprietary capital ratio exceeds 30%

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

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	3,614,362,254	3,374,320,715
3	Construction Work in Progress (107)	200	117,585,328	161,152,909
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,731,947,582	3,535,473,624
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	1,368,455,314	1,298,879,280
6	Net Utility Plant (Enter Total of line 4 less 5)		2,363,492,268	2,236,594,344
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		2,363,492,268	2,236,594,344
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		502,366	571,711
19	(Less) Accum. Prov. for Depr. and Amort. (122)		179,574	242,250
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228	8,349,737	8,364,873
24	Other Investments (124)		692,884	707,401
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)			
29	Special Funds (Non Major Only) (129)		38,324,925	24,743,315
30	Long-Term Portion of Derivative Assets (175)		436,823	14,732
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		48,127,161	34,159,782
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		839,453	1,321,222
36	Special Deposits (132-134)		4,196,423	2,982,246
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		15,412,437	15,795,734
41	Other Accounts Receivable (143)		163,583	116,114
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		605	306
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		18,072,922	23,552,171
45	Fuel Stock (151)	227	57,068,481	78,362,191
46	Fuel Stock Expenses Undistributed (152)	227	2,421,988	2,275,502
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	23,973,785	25,255,256
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	8,515,890	8,554,258
53	(Less) Noncurrent Portion of Allowances	228	8,349,737	8,364,873
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		2,241,790	2,026,633
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		2,956,857	2,653,918
61	Accrued Utility Revenues (173)		9,718,574	
62	Miscellaneous Current and Accrued Assets (174)			12,000,000
63	Derivative Instrument Assets (175)		5,691,344	3,078,245
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		436,823	14,732
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		142,486,362	169,593,579
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		3,934,245	4,533,899
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	731,531,918	682,390,958
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,006,386	893,160
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	31,116,869	40,423,010
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		266,402	300,053
82	Accumulated Deferred Income Taxes (190)	234	82,133,216	74,967,031
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		849,989,036	803,508,111
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,404,094,828	3,243,855,816
	Page 110-111			

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

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250	50,450,000	50,450,000
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)			
7	Other Paid-In Capital (208-211)	253	526,069,518	526,771,324
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118	414,395,958	377,534,237
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)		
16	Total Proprietary Capital (lines 2 through 15)		990,915,476	954,755,561
17	**LONG-TERM DEBT**			
18	Bonds (221)	256		
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		25,000,000
21	Other Long-Term Debt (224)	256	1,215,000,000	1,280,000,000
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		592,937	660,062
24	Total Long-Term Debt (lines 18 through 23)		1,214,407,063	1,304,339,938
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		2,572,811	1,640,229
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		1,348,092	1,260,035
29	Accumulated Provision for Pensions and Benefits (228.3)		6,592,802	6,694,451
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		1,497,209	744,188
32	Long-Term Portion of Derivative Instrument Liabilities		6,782	973,993
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		88,832,997	18,276,486
35	Total Other Noncurrent Liabilities (lines 26 through 34)		100,850,693	29,589,382
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		60,683,964	36,823,006
39	Notes Payable to Associated Companies (233)		183,212,284	49,567,376
40	Accounts Payable to Associated Companies (234)		49,420,756	46,087,714
41	Customer Deposits (235)		38,265,250	38,026,871
42	Taxes Accrued (236)	262	43,482,953.00	48,910,684.00
43	Interest Accrued (237)		10,447,249	12,779,510
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		2,568,209	2,243,842
48	Miscellaneous Current and Accrued Liabilities (242)		11,198,591	24,438,811
49	Obligations Under Capital Leases-Current (243)		350,482	307,148

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
50	Derivative Instrument Liabilities (244)		460,774	8,899,914
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		6,782	973,993
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		400,083,730	267,110,883
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		99,104	94,091
57	Accumulated Deferred Investment Tax Credits (255)	266		
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	11,422,215	10,621,717
60	Other Regulatory Liabilities (254)	278	120,166,057	128,533,845
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	23,637,880	25,206,884
63	Accum. Deferred Income Taxes-Other Property (282)		287,551,685	284,235,237
64	Accum. Deferred Income Taxes-Other (283)		254,960,926	239,368,279
65	Total Deferred Credits (lines 56 through 64)		697,837,867	688,060,053
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,404,094,828	3,243,855,817
	Page 112-113			

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

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	706,582,368	622,721,863			706,582,368	622,721,863				
3	Operating Expenses											
4	Operation Expenses (401)	320	391,169,548	330,952,883			391,169,548	330,952,883				
5	Maintenance Expenses (402)	320	63,670,846	64,173,336			63,670,846	64,173,336				
6	Depreciation Expense (403)	336	102,688,187	105,866,188			102,688,187	105,866,188				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	1,209,506	375,756			1,209,506	375,756				
8	Amort. & Depl. of Utility Plant (404-405)	336	9,598,216	9,961,212			9,598,216	9,961,212				
9	Amort. of Utility Plant Acq. Adj. (406)	336	38,616	38,616			38,616	38,616				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		371,740	7,655,198			371,740	7,655,198				
13	(Less) Regulatory Credits (407.4)		(2,632,082)				(2,632,082)					
14	Taxes Other Than Income Taxes (408.1)	262	26,363,705	27,499,617			26,363,705	27,499,617				
15	Income Taxes - Federal (409.1)	262	3,175,965	(1,838,299)			3,175,965	(1,838,299)				
16	Income Taxes - Other (409.1)	262	338,204	828,944			338,204	828,944				

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
17	Provision for Deferred Income Taxes (410.1)	234, 272	69,566,828	60,148,120			69,566,828	60,148,120				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	68,703,396	87,190,214			68,703,396	87,190,214				
19	Investment Tax Credit Adj. - Net (411.4)	266										
20	(Less) Gains from Disp. of Utility Plant (411.6)		14,518	12,768			14,518	12,768				
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)		180,729	16			180,729	16				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		1,425,167	851,367			1,425,167	851,367				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		603,349,967	519,309,940			603,349,967	519,309,940				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		103,232,401	103,411,923			103,232,401	103,411,923				
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)											
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)											
33	Revenues From Nonutility Operations (417)		330,190	321,610								
34	(Less) Expenses of Nonutility Operations (417.1)		645	180								
35	Nonoperating Rental Income (418)		(5,645)	(5,645)								
36	Equity in Earnings of Subsidiary Companies (418.1)	119										
37	Interest and Dividend Income (419)		1,002,524	201,571								
38	Allowance for Other Funds Used During Construction (419.1)		2,033,764	967,911								
39	Miscellaneous Nonoperating Income (421)		(8,446)	25,006								
40	Gain on Disposition of Property (421.1)											
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		3,351,742	1,510,273								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		174	1,428								

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		1,649,345	971,881								
46	Life Insurance (426.2)											
47	Penalties (426.3)		(6,524)	7,578								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		234,056	188,837								
49	Other Deductions (426.5)		5,442,535	2,557,134								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		7,319,586	3,726,858								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	75,358	45,299								
53	Income Taxes-Federal (409.2)	262	(1,326,337)	(565,609)								
54	Income Taxes-Other (409.2)	262	(70,099)	(41,124)								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272		3,091,861								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272		2,108,512								
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(1,321,078)	421,915								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(2,646,766)	(2,638,500)								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		69,504,133	61,119,830								
63	Amort. of Debt Disc. and Expense (428)		773,406	560,777								
64	Amortization of Loss on Reaquired Debt (428.1)		33,650	33,651								
65	(Less) Amort. of Premium on Debt-Credit (429)											
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)											
67	Interest on Debt to Assoc. Companies (430)		6,186,117	7,125,967								
68	Other Interest Expense (431)		(8,851,602)	2,809,026								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		3,921,790	4,837,681								
70	Net Interest Charges (Total of lines 62 thru 69)		63,723,914	66,811,570								

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		36,861,721	33,961,853								
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		36,861,721	33,961,853								
						Page 114-117						

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

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		377,534,237	343,572,384
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1	Adj to Retained Earnings			(1)
9	TOTAL Credits to Retained Earnings (Acct. 439)			(1)
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		36,861,721	33,961,854
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Common stock			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		414,395,958	377,534,237
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		414,395,958	377,534,237
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)			

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

STATEMENT OF CASH FLOWS

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

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

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Other (Provide details in footnote):		
53.2	(Increase) Decrease in Other Special Deposits	(93,410)	(461,193)
53.3	Proceed From Contribution in Aid of Construction Advance (CIAC)	1,159,425	802,020
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(191,263,421)	(161,146,400)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		465,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
64.2	Long Term Issuances Costs	(76,627)	(4,202,267)
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Proceed on Capital leaseback	1,384	20,598
67.2	Notes Payable to Associated Companies	133,644,908	
67.3	Capital Contributions from Parent	(701,806)	484,361
70	Cash Provided by Outside Sources (Total 61 thru 69)	132,867,860	461,302,692
72	Payments for Retirement of:		
73	Long-term Debt (b)	(90,000,000)	(340,000,000)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Notes Payable to Associated Companies - Retired		(44,860,167)
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	42,867,860	76,442,524
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(481,769)	(1,362,698)
88	Cash and Cash Equivalents at Beginning of Period	1,321,222	2,683,920
90	Cash and Cash Equivalents at End of Period	839,453	1,321,222

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

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

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

(b) Concept: ProceedsFromDisposalOfNoncurrentAssets

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

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

NOTES TO FINANCIAL STATEMENTS

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

INDEX OF NOTES TO FINANCIAL STATEMENTS

	Glossary of Terms for Notes
1.	Organization and Summary of Significant Accounting Policies
2.	New Accounting Standards
3.	Rate Matters
4.	Effects of Regulation
5.	Commitments, Guarantees and Contingencies
6.	Benefit Plans
7.	Derivatives and Hedging
8.	Fair Value Measurements
9.	Income Taxes
10.	Leases
11.	Financing Activities
12.	Related Party Transactions
13.	Property, Plant and Equipment
14.	Revenue from Contracts with Customers

GLOSSARY OF TERMS FOR NOTES

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority-owned subsidiaries and affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KGPCo, KPCo, OPCo and WPCo.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AFUDC	Allowance for Equity Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ASU	Accounting Standards Update.
CCR	Coal Combustion Residual.
CWIP	Construction Work in Progress.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KTCo	AEP Kentucky Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
Liberty	Liberty Utilities Co., a subsidiary of Algonquin Power & Utilities Corporation.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NOL	Net operating losses
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.
OTC	Over-the-counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, jointly-owned by AEGCo and I&M, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TA	Transmission Agreement, effective November 2010, among APCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 163,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

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

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

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

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

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

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

Basis of Accounting

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

- The classification of deferred fuel as noncurrent rather than current.
- The requirement to report deferred tax assets and liabilities separately rather than as a single amount.
- The classification of accrued taxes as a single amount rather than as assets and liabilities.
- The exclusion of current maturities of long-term debt from current liabilities.
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of finance lease payments as operating activities instead of financing activities.
- The classification of gains/losses from disposition of allowances as utility operating expenses rather than as operating revenues.
- The classification of PJM hourly activity for physical transactions as purchases and sales instead of net sales.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.
- The presentation of finance leased assets and their associated accumulated amortization as a single amount instead of as separate amounts.
- The classification of factored accounts receivable expense as a nonoperating expense instead of as an operating expense.
- The classification of certain nonoperating revenues as miscellaneous nonoperating income instead of as operating revenue.
- The classification of certain nonoperating expenses as miscellaneous nonoperating expense instead of as operating expense.
- The separate classification of income tax expense for operating and nonoperating activities instead of as a single income tax expense.
- The classification of gas procurement sales as a reduction of fuel expense rather than as revenue.
- The classification of unamortized loss on reacquired debt in deferred debits rather than in regulatory assets.
- The classification of certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.
- The classification of debt issuance costs as noncurrent assets instead of noncurrent liabilities.
- The classification of rents receivable as rents receivable instead of customer accounts receivable.
- The classification of Non-Service Cost Components of Net Periodic Benefit Cost as Operating Expense instead of Other Income (Expense).
- The classification of operating lease assets as Utility Plant rather than as a noncurrent asset.
- The presentation of obligations under finance and operating leases as a single amount in Obligations Under Capital Leases rather than as separate items.
- The classification of certain expenses in operating income rather than operating expenses.
- The classification of interest on regulated finance leases as operating expense instead of Other Income (Expense).
- The classification of cloud computing implementation costs as Utility Plant rather than as a noncurrent asset.

Accounting for the Effects of Cost-Based Regulation

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

Use of Estimates

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

Cash and Cash Equivalents

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

Supplementary Information

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

Inventory

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

Accounts Receivable and Allowance for Uncollectible Accounts

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

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

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

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

Significant Customer of KPCo: Marathon Petroleum Company	2024	2023
Percentage of Total Revenues	15 %	15 %
Percentage of Accounts Receivable – Customers	47 %	31 %

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

Property, Plant and Equipment

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

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

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

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

Allowance for Funds Used During Construction

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

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

Valuation of Nonderivative Financial Instruments

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

Fair Value Measurements of Assets and Liabilities

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

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

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

Deferred Fuel Costs

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

Revenue Recognition

Regulatory Accounting

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

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

Electricity Supply and Delivery Activities

KPCo recognizes revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes such revenues on the statements of income as the performance obligations of delivering energy to customers are satisfied. Recognized revenues include unbilled as well as-billed amounts. Wholesale transmission revenue is based on a FERC-approved formula rate filing made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under-recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. The annual true-up meets the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations". An estimated annual true-up is recorded by KPCo in the fourth quarter of each calendar year and a final annual true-up is recognized by KPCo in the second quarter of each calendar year following the filing of the annual FERC report. Any portion of the true-up applicable to an affiliated company is recorded as Accounts Receivable from Associated Companies or Accounts Payable to Associated Companies on the balance sheets. Any portion of the true-ups applicable to third-parties is recorded as regulatory assets or regulatory liabilities on the balance sheets. See Note 14 - Revenue from Contracts with Customers for additional information.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

The power produced at KPCo's generation plants is sold to PJM. KPCo also purchases power from PJM to supply power to its customers. Generally, these power sales and purchases are reported on a net basis in revenues on the statements of income.

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

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

Energy Marketing and Risk Management Activities

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

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

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

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

Maintenance

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

Income Taxes

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

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

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

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

Excise Taxes

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

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt is refinanced, the reacquisition costs are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates.
Debt discounts, premiums and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations.

Pension and OPEB Plans

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

Investments Held in Trust for Future Liabilities

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

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

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

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

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

OPEB Plans Assets	Target
Equity	67 %
Fixed Income	32 %
Cash and Cash Equivalents	1 %

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

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

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

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

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

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

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2024 and 2023, the fair value of securities on loan as part of the program was
$60 million and $62 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2024 and 2023.

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

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

Comprehensive Income (Loss)

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

Termination of Planned Disposition of KPCo and KTCo

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

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

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

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2024 through February 13, 2025, the date that KPCo's 2024 Annual Report was available to be issued, and has updated such evaluation for disclosure purposes through April 8, 2025. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

2. NEW ACCOUNTING STANDARDS

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

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

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

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

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

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

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

3. RATE MATTERS

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

Investigation of the Service, Rates and Facilities of KPCo

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

2023 Kentucky Base Rate and Securitization Case

In June 2023, KPCo filed a request with the KPSC for a $93.9 million net annual increase in base rates based upon a proposed 9.9% ROE with the increase to be implemented no earlier than January 2024. In conjunction with its June 2023 filing, KPCo further requested to finance, through the issuance of securitization bonds, approximately $471.2 million of regulatory assets. KPCo's proposal did not address the disposition of its 50% interest in Mitchell Plant, which will be addressed in the future. As of December 31, 2024, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $547.3 million. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

In January 2024, the KPSC issued an order modifying the November 2023 uncontested settlement agreement and approving an annual base rate increase of $60 million based upon a 9.75% ROE effective with billing cycles mid-January 2024. The order reduced KPCo's base rate revenue requirement by $14.2 million to allow recovery of actual test year PJM transmission costs instead of KPCo's requested annual level of costs based on PJM 2023 projected transmission revenue requirements. In February 2024, KPCo filed an appeal with the Commonwealth of Kentucky Franklin Circuit Court, challenging among other aspects of the order, the $14.2 million base rate revenue requirement reduction. In January 2025, the Commonwealth of Kentucky Franklin Circuit Court issued an order agreeing with KPCo's appeal and remanded this issue back to the KPSC with instructions to enter an order, within 30 days, which includes setting rates to allow KPCo to recover the $14.2 million of annual PJM transmission costs effective upon KPCo's January 2024 implementation of updated base rates.

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

Fuel Adjustment Clause (FAC) Review

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

Rockport Offset Recovery

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

2024 Storm Costs

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

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

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

4. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

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

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

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

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

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

COMMITMENTS

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

In accordance with the accounting guidance for "Commitments", the following table summarizes KPCo's actual contractual commitments as of December 31, 2024:

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

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

GUARANTEES

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

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2024, there were no material liabilities recorded for any indemnifications. AEPSC conducts power purchase-and-sale activity on behalf of APCo, I&M, KPCo and WPCo, who are jointly and severally liable for activity conducted on their behalf.

ENVIRONMENTAL CONTINGENCIES

Federal EPA's Revised CCR Rule

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

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

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

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

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

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2024, there is one site for which KPCo has received an information request which could lead to a Potentially Responsible Party designation. In the instance where KPCo has been named a defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.
Management evaluates the potential liability for each site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named for each site and several of the parties are financially sound enterprises. As of December 31, 2024, management's estimates do not anticipate material clean-up costs for the identified site.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

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

In July 2024, KPCo renewed its insurance programs including coverage for wildfire liability. Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cyber security incident or extreme weather or wildfire related liabilities. Future losses or liabilities, if they occur, which are not completely insured, unless recovered through the rate-making process, could reduce future net income and cash flows and impact financial condition.

6. BENEFIT PLANS

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

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

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

Actuarial Assumptions for Benefit Obligations

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

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

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

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

For 2024, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with an average increase of 5.75%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

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

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

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

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

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

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. The plans are monitored to control security diversification and ensure compliance with the investment policy. As of December 31, 2024, the assets were invested in compliance with all investment limits. See “Investments Held in Trust for Future Liabilities” section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status

For the year ended December 31, 2024, the pension plans had an actuarial loss primarily due to an unfavorable demographic experience (updated census data on January 1, 2024), specifically intra-company participant transfer activity from other AEP registrants. These losses were partially offset by the increase in the discount rate. For the year ended December 31, 2024, the OPEB plans had an actuarial gain primarily due to updated per capita cost assumptions and increases in discount rates. These gains were partially offset by the loss for intra-company participant transfer activity from other AEP registrants. For the year ended December 31, 2023, the pension plans had an actuarial loss primarily due to a decrease in the discount rate, and to a lesser extent the effect of demographic experience (updated census data on January 1, 2023). These losses were partially offset by decreasing the cash balance account interest crediting rate. For the year ended December 31, 2023, the OPEB plans had an actuarial loss primarily due to discount rates, as well as actual net benefit payments above expected. These losses were partially offset by updated per capita cost assumptions. The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit and obligation, respectively.

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

Amounts Recognized on the Balance Sheets

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

Amounts Included in Regulatory Assets, Deferred Income Taxes

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

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

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

Determination of Pension Expense

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

Pension and OPEB Assets

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

Pension Plan		OPEB	
December 31,			
2024	2023	2024	2023
3.0 %	2.1 %	3.3 %	2.9 %

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 327.0	$ —	$ —	$ —	$ 327.0	8.9 %
International	290.2	—	—	—	290.2	7.9 %
Common Collective Trusts (b)	176.1	—	—	472.6	648.7	17.7 %
Subtotal – Equities	793.3	—	—	472.6	1,265.9	34.5 %
Fixed Income (a):						
United States Government and Agency Securities	(2.3)	865.6	—	—	863.3	23.6 %
Corporate Debt	—	719.2	—	—	719.2	19.6 %
Foreign Debt	—	136.1	—	—	136.1	3.7 %
State and Local Government	—	25.8	—	—	25.8	0.7 %
Other – Asset Backed	—	0.9	—	—	0.9	— %
Subtotal – Fixed Income	(2.3)	1,747.6	—	—	1,745.3	47.6 %
Infrastructure (b)	—	—	—	112.9	112.9	3.1 %
Real Estate (b)	—	—	—	227.9	227.9	6.2 %
Alternative Investments (b)	—	—	—	223.8	223.8	6.1 %
Cash and Cash Equivalents (b)	—	41.3	—	27.2	68.5	1.9 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	21.9	21.9	0.6 %
Total	$ 791.0	$ 1,788.9	$ —	$ 1,086.3	$ 3,666.2	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 616.8	$ —	$ —	$ —	$ 616.8	34.7 %
International	267.2	—	—	—	267.2	15.0 %
Common Collective Trusts (a)	64.2	—	—	129.4	193.6	10.9 %
Subtotal – Equities	948.2	—	—	129.4	1,077.6	60.6 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	132.9	132.9	7.5 %
United States Government and Agency Securities	(0.5)	157.6	—	—	157.1	8.9 %
Corporate Debt	—	132.3	—	—	132.3	7.5 %
Foreign Debt	—	27.1	—	—	27.1	1.5 %
State and Local Government	57.8	5.0	—	—	62.8	3.5 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	57.3	322.2	—	132.9	512.4	28.9 %
Trust Owned Life Insurance:						
International Equities	—	23.1	—	—	23.1	1.3 %
United States Bonds	—	118.2	—	—	118.2	6.7 %
Subtotal – Trust Owned Life Insurance	—	141.3	—	—	141.3	8.0 %
Cash and Cash Equivalents (a)	27.6	—	—	3.1	30.7	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	13.9	13.9	0.8 %
Total	$ 1,033.1	$ 463.5	$ —	$ 279.3	$ 1,775.9	100.0 %

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

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 411.3	$ —	$ —	$ —	$ 411.3	10.0 %
International	389.8	—	—	—	389.8	9.5 %
Common Collective Trusts (b)	—	—	—	420.9	420.9	10.2 %
Subtotal – Equities	801.1	—	—	420.9	1,222.0	29.7 %
Fixed Income (a):						
United States Government and Agency Securities	8.3	1,099.2	—	—	1,107.5	26.9 %
Corporate Debt	—	894.8	—	—	894.8	21.7 %
Foreign Debt	—	167.1	—	—	167.1	4.1 %
State and Local Government	—	38.7	—	—	38.7	0.9 %
Other – Asset Backed	—	1.3	—	—	1.3	— %
Subtotal – Fixed Income	8.3	2,201.1	—	—	2,209.4	53.6 %
Infrastructure (b)	—	—	—	101.4	101.4	2.5 %
Real Estate (b)	—	—	—	239.3	239.3	5.8 %
Alternative Investments (b)	—	—	—	241.8	241.8	5.8 %
Cash and Cash Equivalents (b)	—	51.0	—	33.8	84.8	2.1 %
Other – Pending Transactions and Accrued Income (c)	—	—	0.1	19.4	19.5	0.5 %
Total	$ 809.4	$ 2,252.1	$ 0.1	$ 1,056.6	$ 4,118.2	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 540.6	$ —	$ —	$ —	$ 540.6	32.3 %
International	288.4	—	—	—	288.4	17.2 %
Common Collective Trusts (a)	—	—	—	131.6	131.6	7.9 %
Subtotal – Equities	829.0	—	—	131.6	960.6	57.4 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	146.7	146.7	8.8 %
United States Government and Agency Securities	1.4	163.3	—	—	164.7	9.8 %
Corporate Debt	—	149.0	—	—	149.0	8.9 %
Foreign Debt	—	28.6	—	—	28.6	1.7 %
State and Local Government	41.5	7.8	—	—	49.3	3.0 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.9	348.9	—	146.7	538.5	32.2 %
Trust Owned Life Insurance:						
International Equities	—	22.3	—	—	22.3	1.3 %
United States Bonds	—	130.0	—	—	130.0	7.8 %
Subtotal – Trust Owned Life Insurance	—	152.3	—	—	152.3	9.1 %
Cash and Cash Equivalents (a)	25.9	—	—	2.9	28.8	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(6.9)	(6.9)	(0.4)%
Total	$ 897.8	$ 501.2	$ —	$ 274.3	$ 1,673.3	100.0 %

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

Accumulated Benefit Obligation

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

	December 31, 2024	December 31, 2023
	(in thousands)	
Qualified Pension Plan	$ 111,430	$ 89,419
Nonqualified Pension Plan	17	7
Total Accumulated Benefit Obligation	$ 111,447	$ 89,426

Obligations in Excess of Fair Values

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

Projected Benefit Obligation

	Underfunded Pension Plans	
	December 31, 2024	December 31, 2023
	(in thousands)	
Projected Benefit Obligation	$ 114,278	$ 92,174
Fair Value of Plan Assets	109,278	87,421
Underfunded Projected Benefit Obligation	$ (5,000)	$ (4,753)

Accumulated Benefit Obligation

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

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the Pension and OPEB plans of $2.1 million and $8 thousand, respectively, during 2025. The estimated contributions to the pension trust are at least the minimum amount required by the Employee Retirement Income Security Act and additional discretionary contributions may also be made to maintain the funded status of the plan.

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

	Estimated Payments	
	Pension Plans	OPEB
	(in thousands)	
2025	$ 10,321	$ 4,232
2026	9,859	4,032
2027	10,430	3,833
2028	9,849	3,620
2029	9,810	3,509
Years 2030 to 2034, in Total	44,623	15,675

Components of Net Periodic Benefit Cost (Credit)

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

	Pension Plans		OPEB	
	Years Ended December 31,			
	2024	2023	2024	2023
	(in thousands)			
Service Cost	$ 1,604	$ 1,474	$ 56	$ 63
Interest Cost	6,127	4,814	1,373	1,269
Expected Return on Plan Assets	(9,422)	(7,131)	(3,853)	(3,201)
Amortization of Prior Service Credit	—	—	(374)	(1,856)
Amortization of Net Actuarial Loss	93	—	118	445
Settlements	1,689	—	—	—
Net Periodic Benefit Cost (Credit)	91	(843)	(2,680)	(3,280)
Capitalized Portion	(868)	(812)	(30)	(35)
Net Periodic Benefit Credit Recognized in Expense	$ (777)	$ (1,655)	$ (2,710)	$ (3,315)

American Electric Power System Retirement Savings Plan

KPCo participates in an AEPSC sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions totaled $1.4 million in 2024 and $1.4 million in 2023.

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of KPCo.

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

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

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

Primary Risk Exposure	December 31, 2024	December 31, 2023	Unit of Measure
	(in thousands)		
Commodity:			
Power	4,832	3,303	MWhs
Natural Gas	9,783	9,761	MMBtus
Heating Oil and Gasoline	48	253	Gallons

Cash Flow Hedging Strategies

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

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

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON KPCo's FINANCIAL STATEMENTS

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

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third-party contractual agreements and risk profiles. KPCo netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $395 thousand and $1.2 million as of December 31, 2024 and 2023, respectively. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets as of December 31, 2024 and 2023.

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

Statement of Financial Position Location	December 31, 2024 Risk Management Contracts – Commodity (a)	Gross Amounts Offset on the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented on the Statement of Financial Position (c)
		(in thousands)	
Derivative Instrument Assets	$ 6,775	$ (1,084)	$ 5,691
Long-term Portion of Derivative Instrument Assets	595	(158)	437
Derivative Instrument Liabilities	1,939	(1,478)	461
Long-term Portion of Derivative Instrument Liabilities	165	(158)	7

Balance Sheet Location	December 31, 2023 Risk Management Contracts – Commodity (a)	Gross Amounts Offset on the Balance Sheets (b)	Net Amounts of Assets/Liabilities Presented on the Balance Sheets (c)
		(in thousands)	
Derivative Instrument Assets	$ 3,590	$ (511)	$ 3,079
Long-term Portion of Derivative Instrument Assets	230	(215)	15
Derivative Instrument Liabilities	10,564	(1,664)	8,900
Long-term Portion of Derivative Instrument Liabilities	1,189	(215)	974

(a) Derivative instruments within this category are disclosed as gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.

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

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2024	2023
	(in thousands)	
Operating Revenues	$ 3	$ 1
Operation Expenses	96	77
Maintenance Expenses	(4)	—
Other Regulatory Assets (a)	10,023	(10,043)
Other Regulatory Liabilities (a)	8,536	1,209
Total Gain (Loss) on Risk Management Contracts	$ 18,654	$ (8,756)

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

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

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

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

Accounting for Cash Flow Hedging Strategies

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

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

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

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

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

Credit Risk

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

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

Collateral Triggering Events

Credit Downgrade Triggers

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. KPCo has not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. As of December 31, 2024 and 2023, KPCo did not have derivative contracts with collateral triggering events in a net liability position.

Cross-Acceleration Triggers

Certain interest rate derivative contracts contain cross-acceleration provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-acceleration provisions could be triggered if there was a non-performance event by KPCo under any of their outstanding debt of at least $50 million and the lender on that debt has accelerated the entire repayment obligation. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-acceleration provisions in contracts. KPCo had no derivative contracts with cross-acceleration provisions in a net liability position and no cash collateral posted as of December 31, 2024 and 2023. If a cross-acceleration provision would have been triggered, settlement at fair value would have been required.

Cross-Default Triggers

In addition, a majority of KPCo's non-exchange-traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third-party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. KPCo had derivative contracts with cross-default provisions in a net liability position of $212 thousand and $8 million, and no cash collateral posted as of December 31, 2024 and 2023, respectively. If a cross-default provision would have been triggered, settlement at fair value would have been required.

8. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

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

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

	December 31,			
	2024		2023	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 1,214,407	$ 1,222,803	$ 1,304,340	$ 1,302,987

Fair Value Measurements of Financial Assets and Liabilities

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

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2024

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

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

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

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

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

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

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

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

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of December 31, 2024 and 2023:

Significant Unobservable Inputs
December 31, 2024

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

Significant Unobservable Inputs
December 31, 2023

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

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

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of December 31, 2024 and 2023:

Uncertainty of Fair Value Measurements

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

9. INCOME TAXES

Income Tax Expense (Benefit)

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

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

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

	Years Ended December 31, 2024	2023
	(in thousands)	
Net Income	$ 36,862	$ 33,962
Income Tax Expense (Benefit)	2,981	(27,675)
Pretax Income	$ 39,843	$ 6,287
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 8,367	$ 1,320
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Reversal of Original Flow-Through	840	972
Removal Costs	1,668	(2,587)
State and Local Income Taxes, Net	(818)	(397)
Tax Reform Excess ADIT Reversal	(6,626)	(25,944)
Federal Return to Provision Adjustment	—	(560)
AFUDC Equity	(422)	(195)
Other	(28)	(284)
Income Tax Expense (Benefit)	$ 2,981	$ (27,675)
Effective Income Tax Rate	7.5 %	(440.2) %

Net Deferred Tax Liability

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

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

Federal Income Tax Audit Status

KPCo and other AEP subsidiaries are not currently under IRS audit and the statute of limitations ("SOL") for the IRS to examine KPCo and other AEP subsidiaries' originally filed federal return has expired for tax years prior to 2017. KPCo and other AEP subsidiaries agreed to extend the SOL on the 2017-2020 tax returns to May 31, 2025, to allow the Congressional Joint Committee on Taxation ("JCT") adequate time to complete its review of the now closed IRS audit. Following JCT's approval, KPCo and other AEP subsidiaries received IRS confirmation that tax years 2017-2020 are now effectively closed as they only remain open for changes to other non-consolidated entities that KPCo and other AEP subsidiaries hold an interest in.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. KPCo and other AEP subsidiaries are not currently under any state and local income tax examinations. Generally, the SOL have expired for tax years prior to 2017. In addition, management is monitoring and continues to evaluate the potential impact of federal legislation and corresponding state conformity.

Net Income Tax Operating Loss Carryforward

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

10. LEASES

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

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

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

Lease Rental Costs	Years Ended December 31, 2024	2023
	(in thousands)	
Operating Lease Cost	$ 258	$ 71
Finance Lease Cost:		
Amortization of Finance Leases	118	83
Interest on Finance Leases	55	22
Total Lease Rental Costs (a)	$ 431	$ 176

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

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

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

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

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

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

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

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

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

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

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

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of December 31, 2024, the maximum potential loss for these lease agreements was $121 thousand assuming the fair value of the equipment is zero at the end of the lease term.

Lessor Activity

KPCo's lessor activity was immaterial as of and for the twelve months ended December 31, 2024 and December 31, 2023, respectively.

11. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding:

Type of Debt	Maturity	Weighted-Average Interest Rate as of December 31, 2024	Interest Rate Ranges as of December 31, 2024	2023	Outstanding as of December 31, 2024	2023
					(in thousands)	
Senior Unsecured Notes	2026-2047	5.55%	3.35%-8.13%	3.13%-8.13%	$ 1,000,000	$ 1,065,000
Pollution Control Bonds	2026 (a)	4.70%	4.70%	4.70%	65,000	65,000
Notes Payable - Affiliated		—%	—%	5.29%	—	25,000
Other Long-term Debt	2025	5.42%	5.42%	6.41%	150,000	150,000
Unamortized Discount, Net					(593)	(660)
Total Long-term Debt					$ 1,214,407	$ 1,304,340

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

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

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

Long-term Debt Subsequent Event

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

Financing Plan

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

Dividend Restrictions

KPCo pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KPCo to transfer funds to Parent in the form of dividends.
All of the dividends declared by KPCo are subject to a Federal Power Act requirement that prohibits the payment of dividends out of capital accounts in certain circumstances; payment of dividends is generally allowed out of retained earnings.

KPCo has credit agreements that contain a covenant that limit its debt to capitalization ratio to 67.5%. As of December 31, 2024, KPCo did not exceed its debt to capitalization limit. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The most restrictive dividend limitation for KPCo is through the Credit Agreements. As of December 31, 2024, the maximum amount of restricted net assets of KPCo that may not be distributed to Parent in the form of a loan, advance or dividend was $671.9 million.

The Federal Power Act restriction does not limit the ability of KPCo to pay dividends out of retained earnings. The credit agreement covenant restrictions can limit the ability of KPCo to pay dividends out of retained earnings. As of December 31, 2024, the amount of any such restrictions was $95.4 million.

Corporate Borrowing Program – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2024 and 2023 are included in Notes Payable to Associated Companies on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits are described in the following table:

Years Ended December 31,	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2024	$ 206,113	$ —	$ 93,082	$ —	$ 183,212	$ 250,000
2023	169,398	243,803	112,116	243,764	49,567	250,000

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

Years Ended December 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2024	5.79 %	4.74 %	— %	— %	5.27 %	— %
2023	5.81 %	4.66 %	5.72 %	5.72 %	5.53 %	5.72 %

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

	Years Ended December 31,	
	2024	2023
	(in thousands)	
Interest Expense	$ 5,345	$ 6,399
Interest Income	—	116

Securitized Accounts Receivables – AEP Credit

Under an affiliated receivables sales arrangement, KPCo sold, without recourse, certain of its customer accounts receivable and accrued utility revenues balances to AEP Credit. In January 2022, due to the expected sale to Liberty, KPCo ceased selling accounts receivable to AEP Credit. As a result, in the first quarter of 2022, KPCo began recording an allowance for uncollectible accounts on its balance sheet for those receivables no longer sold to AEP Credit. In September 2023, KPCo resumed selling accounts receivable to AEP Credit, due to the termination of the sale to Liberty, and the balance in KPCo's allowance for uncollectible accounts was reversed. KPCo is charged a fee for each sale that is based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience from previous purchases of KPCo's customer accounts receivable. No allowance for credit losses is recognized within KPCo's financial statements for customer accounts receivable sold to AEP Credit, and any bad debt stemming from these receivables would be recognized by AEP Credit. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's statements of income. KPCo manages and services its accounts receivables sold.

AEP Credit's receivables securitization agreement provides a commitment of $900 million from bank conduits to purchase receivables and expires in September 2026. As of December 31, 2024, KPCo was in compliance with all requirements under the agreement.

KPCo's amounts of accounts receivable and accrued unbilled revenues under the sale of receivables agreement were $53.4 million and $42.7 million as of December 31, 2024 and 2023, respectively.

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

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

12. RELATED PARTY TRANSACTIONS

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

Intercompany Billings

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

Power Coordination Agreement

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

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

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet and then transfers the cost to the affiliate for reimbursement. KPCo recorded its assigned portion of these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. KPCo's billed amounts were $418 thousand and $177 thousand for the years ended December 31, 2024 and 2023, respectively.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions and the net book value of all sales and purchases for the years ended December 31, 2024 and 2023 were not material. These sales and purchases are recorded in Utility Plant on the balance sheets.

Unit Power Agreements

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

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

PJM Transmission Service Charges

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

KPCo's net charges recorded as a result of the TA for the years ended December 31, 2024 and 2023 were $75.5 million and $66 million, respectively, and were recorded in Operation Expenses on KPCo's statements of income.

Affiliated Revenues

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

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

13. PROPERTY, PLANT AND EQUIPMENT

Depreciation

KPCo provides for depreciation of Utility Plant on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides total regulated annual composite depreciation rates and depreciable lives for KPCo. Nonregulated depreciation rate ranges and depreciable life ranges are not applicable or not meaningful for 2024 and 2023.

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

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

Asset Retirement Obligations (ARO)

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

The following is a reconciliation of the 2024 and 2023 aggregate carrying amounts of ARO for KPCo:

Year	ARO as of January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled (a)	Revisions in Cash Flow Estimates (a)	ARO as of December 31,
			(in thousands)			
2024	$ 18,276	$ 2,587	$ 66,399	$ (924)	$ 2,495	$ 88,833
2023	18,477	811	—	(1,088)	76	18,276

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

Jointly-owned Electric Facilities

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

	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
KPCo's Share as of December 31, 2024					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,088,611	$ 3,680	$ 545,520
KPCo's Share as of December 31, 2023					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,055,915	$ 21,596	$ 534,308

(a) Operated by WPCo.

14. REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregated Revenues from Contracts with Customers

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

	Years Ended December 31,	
	2024	2023
	(in thousands)	
Retail Revenues:		
Residential Revenues	$ 278,699	$ 246,124
Commercial Revenues	190,145	159,443
Industrial Revenues	167,490	149,336
Other Retail Revenues	2,147	1,979
Total Retail Revenues	638,481	556,882
Wholesale Revenues:		
Generation Revenues	23,662	20,812
Transmission Revenues (a)	30,070	28,799
Total Wholesale Revenues	53,732	49,611
Other Revenues from Contracts with Customers (b)	11,486	11,176
Total Revenues from Contracts with Customers	703,699	617,669
Other Revenues:		
Alternative Revenue Programs (c)	2,880	5,052
Other Revenues	3	1
Total Other Revenues	2,883	5,053
Total Operating Revenues	$ 706,582	$ 622,722

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues were $13.8 million and $17 million for years ended December 31, 2024 and 2023, respectively.
(b) Amounts include affiliated and nonaffiliated revenues.
(c) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

Performance Obligations

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

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

Retail Revenues

KPCo has performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer's usage requirements.
Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between KPCo and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice.

Wholesale Revenues - Generation

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

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

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

Wholesale Revenues - Transmission

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

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

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

Fixed Performance Obligations

The following table represents KPCo's remaining fixed performance obligations satisfied over time as of December 31, 2024. Fixed performance obligations primarily include electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. KPCo elected to apply the exemption to not disclose the value of unsatisfied performance obligations for contracts with an original expected term of one year or less. Due to the annual establishment of revenue requirements, transmission revenues are excluded from the table below. The amounts shown in the table below include affiliated and nonaffiliated revenues.

2025	2026-2027	2028-2029	After 2029	Total
		(in thousands)		
$ 1,435	$ 2,870	$ 2,870	$ 1,435	$ 8,610

Contract Assets and Liabilities

Contract assets are recognized when KPCo has a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. KPCo did not have material contract assets as of December 31, 2024 and 2023, respectively.

When KPCo receives consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheet in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. KPCo's contract liabilities typically arise from advanced payments of services provided primarily with respect to joint use agreements for utility poles. KPCo did not have material contract liabilities as of December 31, 2024 and 2023, respectively.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on KPCo's balance sheets within the Customer Accounts Receivable line item. KPCo's balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Customer Accounts Receivable were not material as of December 31, 2024 and 2023, respectively. See "Securitized Accounts Receivable - AEP Credit" section of Note 11 for additional information.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable from Associated Companies on KPCo's balance sheets were $14.1 million and $12.2 million, respectively, as of December 31, 2024 and December 31, 2023.

Contract Costs

Contract costs to obtain or fulfill a contract are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and neither bifurcated nor reclassified between current assets and deferred debits on KPCo's balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Operation Expenses on KPCo's statements of income. KPCo did not have material contract costs as of December 31, 2024 and 2023, respectively.

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

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year									
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value									
4	Total (lines 2 and 3)								33,961,853	33,961,853
5	Balance of Account 219 at End of Preceding Quarter/Year									
6	Balance of Account 219 at Beginning of Current Year									
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)								36,861,721	36,861,721
10	Balance of Account 219 at End of Current Quarter/Year									

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

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

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

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	3,319,600,129	3,319,600,129					
4	Property Under Capital Leases	2,882,654	2,882,654					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	291,077,800.00	291,077,800.00					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	3,613,560,583	3,613,560,583					
9	Leased to Others							
10	Held for Future Use	801,671	801,671					
11	Construction Work in Progress	117,585,328	117,585,328					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	3,731,947,582	3,731,947,582					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,368,455,314	1,368,455,314					
15	Net Utility Plant (13 less 14)	2,363,492,268	2,363,492,268					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	1,336,283,179	1,336,283,179					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	32,172,135	32,172,135					
22	Total in Service (18 thru 21)	1,368,455,314	1,368,455,314					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,368,455,314	1,368,455,314					

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

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

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

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents	52,919					52,919
4	(303) Miscellaneous Intangible Plant	60,894,415	5,118,926	9,190,306			56,823,035
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	60,947,334	5,118,926	9,190,306			56,875,954
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	4,859,778	126,334				4,986,112
9	(311) Structures and Improvements	81,952,866	22,190,500	1,842,061			102,301,305
10	(312) Boiler Plant Equipment	972,789,844	12,785,698	6,435,324			979,140,218
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	121,751,934	1,353,326	2,235,440			120,869,820
13	(315) Accessory Electric Equipment	32,777,792	1,961,744	144,603			34,594,933
14	(316) Misc. Power Plant Equipment	14,093,917	311,233	87,427			14,317,723
15	(317) Asset Retirement Costs for Steam Production	11,312,853	22,728,672				34,041,525
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,239,538,984	61,457,507	10,744,855			1,290,251,636
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						
20	(322) Reactor Plant Equipment						
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights						
28	(331) Structures and Improvements						
29	(332) Reservoirs, Dams, and Waterways						
30	(333) Water Wheels, Turbines, and Generators						
31	(334) Accessory Electric Equipment						
32	(335) Misc. Power Plant Equipment						
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)						
36	D. Other Production Plant						
37	(340) Land and Land Rights						
38	(341) Structures and Improvements						
39	(342) Fuel Holders, Products, and Accessories						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
40	(343) Prime Movers						
41	(344) Generators						
42	(345) Accessory Electric Equipment						
43	(346) Misc. Power Plant Equipment						
44	(347) Asset Retirement Costs for Other Production						
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)						
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,239,538,984	61,457,507	10,744,855			1,290,251,636
47	3. Transmission Plant						
48	(350) Land and Land Rights	40,025,350	5,956,798				45,982,148
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	16,877,997	13,164,471	88,560			29,953,908
50	(353) Station Equipment	291,476,769	22,993,829	1,858,647			312,611,951
51	(354) Towers and Fixtures	101,216,713	23,042,714	118,653			124,140,774
52	(355) Poles and Fixtures	212,039,911	34,930,674	3,250,705			243,719,880
53	(356) Overhead Conductors and Devices	171,266,189	17,060,360	272,123			188,054,426
54	(357) Underground Conduit	4,863,115	998,834				5,861,949
55	(358) Underground Conductors and Devices	497,623	64,343				561,966
56	(359) Roads and Trails						
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	838,263,667	118,212,023	5,588,688			950,887,002
59	4. Distribution Plant						
60	(360) Land and Land Rights	9,772,001	2,200,701				11,972,702
61	(361) Structures and Improvements	11,986,226	7,236,749	1,483			19,221,492
62	(362) Station Equipment	149,829,164	21,250,908	895,078			170,184,994
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	306,949,264	23,310,479	1,657,504			328,602,239
65	(365) Overhead Conductors and Devices	324,443,634	16,051,304	1,468,727			339,026,211
66	(366) Underground Conduit	9,986,143	139,874	2,140			10,123,877
67	(367) Underground Conductors and Devices	13,075,532	317,755	25,296			13,367,991
68	(368) Line Transformers	164,654,798	7,383,986	1,959,698			170,079,086
69	(369) Services	76,585,841	2,950,175	375,321			79,160,695
70	(370) Meters	25,537,484	353,999	269,625			25,621,858
71	(371) Installations on Customer Premises	20,317,894	2,859,433	2,451,960			20,725,367
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	5,363,552	605,519	314,620			5,654,451
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,118,501,533	84,660,882	9,421,452			1,193,740,963
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	2,042,937	91,754				2,134,691
87	(390) Structures and Improvements	27,976,747	1,480,294	718,733			28,738,308
88	(391) Office Furniture and Equipment	3,445,780	364,725				3,810,505
89	(392) Transportation Equipment	23,585,710	482,795				24,068,505
90	(393) Stores Equipment	304,824	152,146	27,200			429,770
91	(394) Tools, Shop and Garage Equipment	7,697,680	413,402	2,744			8,108,338
92	(395) Laboratory Equipment	225,704					225,704

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
93	(396) Power Operated Equipment	2,221,244					2,221,244
94	(397) Communication Equipment	44,234,259	2,649,023	54,040			46,829,242
95	(398) Miscellaneous Equipment	2,469,745		272,497			2,197,248
96	SUBTOTAL (Enter Total of lines 86 thru 95)	114,204,630	5,634,139	1,075,214			118,763,555
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant	158,819					158,819
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	114,363,449	5,634,139	1,075,214			118,922,374
100	TOTAL (Accounts 101 and 106)	3,371,614,967	275,083,477	36,020,515			3,610,677,929
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	3,371,614,967	275,083,477	36,020,515			3,610,677,929
	Page 204-207						

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ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
2						
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47	TOTAL					

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

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Ramey Substation (4205)	10/01/2009	12/31/2025	556,145.00
3	Items under $250,000			245,526
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
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47	TOTAL			801,671

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

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

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

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

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

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

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

FOOTNOTE DATA

(a) Concept: OtherAccounts

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

(b) Concept: CostOfRemovalOfPlant

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

(c) Concept: SalvageValueOfRetiredPlant

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

(d) Concept: OtherAdjustmentsToAccumulatedDepreciation

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

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
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27								
28								
29								
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								
41								

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
42	Total Cost of Account 123.1 $		Total					
Page 224-225								

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MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	78,362,191	57,068,481	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	2,275,502	2,421,988	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	12,422,278	13,556,414	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	12,419,783	9,971,316	Electric
8	Transmission Plant (Estimated)	45,182	10,431	Electric
9	Distribution Plant (Estimated)	288,376	349,096	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[a]79,637	[b]86,528	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	25,255,256	23,973,785	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies	105,892,949	83,464,254	

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FOOTNOTE DATA

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

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Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	313,079	8,472,258	54,080		54,079		54,080		1,379,709		1,855,027	8,472,258
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)			5,263						44,351		49,614	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	1,886	38,368									1,886	38,368
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Consent Decree Surrenders			39,166								39,166	
23													
24													
25													
26													
27													
28	Total			39,166								39,166	
29	Balance-End of Year	311,193	8,433,890	20,177		54,079		54,080		1,424,060		1,863,589	8,433,890
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains		15										15
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	362		362		362		362		24,244		25,692	
37	Add: Withheld by EPA									723		723	
38	Deduct: Returned by EPA												
39	Cost of Sales	362								361		723	

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
40	Balance-End of Year			362		362		362		24,606		25,692	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												
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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	60,367	82,000									60,367	82,000
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	361		4,714								5,075	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9	Monongahela Power	110	157,143									110	157,143
10													
11													
12													
13													
14													
15	Total	110	157,143									110	157,143
16													
17	Relinquished During Year:												
18	Charges to Account 509	2,710	42,857									2,710	42,857
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Monongahela Power	200	114,286									200	114,286
23													
24													
25													
26													
27													
28	Total	200	114,286									200	114,286
29	Balance-End of Year	57,928	82,000	4,714								62,642	82,000
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)		180,714										180,714
34	Gains		180,714										180,714
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												
Page 228(ab)-229(ab)b													

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EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

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

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

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

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

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	AF1-130	7,643	186	258	186
3	AF1-162	2,174	186	2,174	186
4	AF2-018	2,830	186	3,457	186
5	AG1-066	21,878	186	21,878	186
6	AH1-644	(822)	186		
7	AI2-342	(155)	186		
20	Total				
21	**Generation Studies**				
39	Total				
40	Grand Total				

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OTHER REGULATORY ASSETS (Account 182.3)

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

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
35	2023 Kentucky Storm Deferral	8,415,089	4,099,303	146, 182, 234, 571, 573	4,099,303	8,415,089
36	KY Deferred Securitization Exp	592,623	1,674,499		0	2,267,123
37	Deferred NOLC Equity Carrying Charges			182	4,360,996	(4,360,996)
38	BSDR Deferred Carrying Charges		17,244,859			17,244,859
39	BSDR Deferred Equity Carrying Charges			182, 431	7,135,402	(7,135,402)
40	Deferred NOLC Carrying Charges		4,360,996			4,360,996
41	2024 PJM Annual Transmission Requirement		101,279	447	30,423	70,856
42	2024 Kentucky Storm Deferral		10,783,447			10,783,447
44	TOTAL	682,390,958	199,147,081		150,006,121	731,531,918
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MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

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

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

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	EXCESS ADFIT 282 - PROTECTED.	30,889,970	6,268,043
3	NOL-STATE C/F-DEF TAX ASSET-L/T	15,625,910	(2,769,455)
4	ACCRD BOOK ARO EXPENSE - SFAS 143	3,635,783	16,474,882
5	INT EXP CAPITALIZED FOR TAX	7,010,986	17,671,086
6	REG ASSET-UNRECOVERED PLANT-BIG SANDY	2,838,980	(4,873,718)
7	Other	(36,505,726)	(563,751)
8	TOTAL Electric (Enter Total of lines 2 thru 7)	23,495,903	32,207,087
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	51,471,128	49,926,129
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	74,967,031	82,133,216

Notes

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

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

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

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

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

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

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2		2,000,000	50.00		1,009,000	50,450,000				
6	Total	2,000,000			1,009,000	50,450,000				
7	Preferred Stock (Account 204)									
8										
9										
10										
11	Total									

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

Other Paid-in Capital

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

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

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	523,324,094
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	523,324,094
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	3,447,230
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	(701,806)
16	Ending Balance Amount	2,745,424
17	**Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	526,069,518

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

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

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

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2													
3													
4													
5	Subtotal												
6	Reacquired Bonds (Account 222)												
7													
8													
9													
10	Subtotal												
11	Advances from Associated Companies (Account 223)												
12	Notes Payable to Parent -AEP Company ,Inc Interest Rate: 5.29%		25,000,000					06/13/2023	06/13/2028	06/13/2023	06/13/2028		841,257
13	Subtotal		25,000,000										841,257
14	Other Long Term Debt (Account 224)												
15	Senior Unsecured Notes - 5.625%, Series D		75,000,000					06/13/2003	12/01/2032	06/13/2003	12/01/2032	75,000,000	4,218,750
16	Senior Unsecured Notes - 8.030%		30,000,000					06/18/2009	06/18/2029	06/18/2009	06/18/2029	30,000,000	2,409,000
17	Senior Unsecured Notes - 8.130%		60,000,000					06/18/2009	06/18/2039	06/18/2009	06/18/2039	60,000,000	4,878,000
18	Senior Unsecured Notes - 4.180%, Series A		120,000,000					09/30/2014	09/30/2026	09/30/2014	09/30/2026	120,000,000	5,016,000
19	Senior Unsecured Notes - 4.33%, Series B		80,000,000					12/30/2014	12/30/2026	12/30/2014	12/30/2026	80,000,000	3,464,000
20	(a) West Virginia Economic Development Authority Mitchell Project Series 2014A State Commission Authority Case# 2013-00410 Maturity Extended to 6/17/2026		65,000,000					06/26/2014	04/01/2036	06/26/2014	06/17/2026	65,000,000	3,055,000

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
21	Senior Unsecured Notes - 3.13%, Series F		65,000,000					09/12/2017	09/12/2024	09/12/2017	09/12/2024		1,418,499
22	Senior Unsecured Notes - 3.35%, Series G		40,000,000					09/12/2017	09/12/2027	09/12/2017	09/12/2027	40,000,000	1,340,000
23	Senior Unsecured Notes - 3.45%, Series H		165,000,000					09/12/2017	09/12/2029	09/12/2017	09/12/2029	165,000,000	5,692,500
24	Senior Unsecured Notes - 4.12%, Series I		55,000,000					09/12/2017	09/12/2047	09/12/2017	09/12/2047	55,000,000	2,266,000
25	Senior Unsecured Notes - 7.00%, Series JState Commission Authority Case No. 2023-00029		375,000,000		3,081,116		671,250	11/10/2023	11/15/2033	11/10/2023	11/15/2033	375,000,000	26,250,000
26	[b] Term Loan - KY State Commission Authority: Case No. 2021-00131 Maturity Extended to 6/30/2025		150,000,000					06/17/2021	06/30/2024	06/17/2021	06/30/2024		
27								06/30/2024	06/30/2025	06/30/2024	06/30/2025	150,000,000	9,496,384
27	Subtotal		1,280,000,000		3,081,116		671,250					1,215,000,000	69,504,133
33	TOTAL		1,305,000,000									1,215,000,000	[a] 70,345,390

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

FOOTNOTE DATA

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

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	36,861,721
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	[a](9,161,127)
28	Show Computation of Tax:	
29		
30		
31		
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44		

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

FOOTNOTE DATA

(a) Concept: FederalTaxNetIncome

FOOTNOTE DATA

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

FOOTNOTE DATA

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

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

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

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

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

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR	
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)
1	Pers Prop Leased	Property Tax	KY		938,315.00	0.00	61,055.00	47,017.00		952,353.00	0.00
2	Pers Prop Leased	Property Tax	WV		0.00	0.00	0.00	0.00		0.00	0.00
3	Real & Pers Prop	Property Tax	KY		42,178,162.00	0.00	9,247,670.00	17,000,266.00		34,425,566.00	0.00
4	Real & Pers Prop	Property Tax	MI		0.00	0.00	0.00	0.00		0.00	0.00
5	Real & Pers Prop	Property Tax	WV		4,326,443.00	0.00	3,123,634.00	2,867,073.00		4,583,004.00	0.00
6	Real Prop Leased	Property Tax	KY		10,629.00	0.00	21,491.00	32,120.00		0.00	0.00
7	Unemployment Tax	Unemployment Tax	KY		2,141.00	0.00	10,017.00	9,992.00		2,166.00	0.00
8	Unemployment Tax	Unemployment Tax	OH		0.00	0.00	27.00	0.00		27.00	0.00
9	Unemployment Tax	Unemployment Tax	WV		2.00	0.00	1,746.00	1,450.00		298.00	0.00
10	Unemployment Tax	Unemployment Tax	(blank)		3,748.00	0.00	13,718.00	12,920.00		4,546.00	0.00
11	Sales Tax	Sales And Use Tax	KY		0.00	311,523.00	0.00	15,761.00		0.00	327,284.00
12	Use Tax	Sales And Use Tax	KY		(533,551.00)	49,105.00	2,828,453.00	2,206,374.00		109,763.00	70,340.00
13	Use Tax	Sales And Use Tax	WV		2,876.00	0.00	54,753.00	56,008.00		1,621.00	0.00
14	City Tax	Income Tax			(49,346.00)	0.00	0.00	0.00		(49,346.00)	0.00
15	Federal Income	Income Tax			841,088.00	0.00	2,551,433.00	1,201,612.00		2,190,909.00	0.00
16	State Income Tax	Income Tax	IL		7,011.00	0.00	10,312.00	0.00		17,323.00	0.00
17	State Income Tax	Income Tax	KY		(232,374.00)	0.00	(225,947.00)	272,000.00		(730,321.00)	0.00
18	State Income Tax	Income Tax	MI		0.00	0.00	0.00	0.00		0.00	0.00
19	State Income Tax	Income Tax	MULTI		(360,769.00)	0.00	0.00	0.00		(360,769.00)	0.00
20	State Income Tax	Income Tax	WV		827,933.00	0.00	483,740.00	0.00		1,311,673.00	0.00
21	State Income Tax	Income Tax	CA		0.00	0.00	0.00	0.00		0.00	0.00
22	State Income Tax FIN48	Income Tax	FIN48		0.00	0.00	0.00	0.00		0.00	0.00
23	Excise Tax	Fuel Tax			0.00	0.00	14,640.00	14,640.00		0.00	0.00
24	Federal Insurance Tax	Federal Insurance Tax	(blank)		170,435.00	0.00	2,637,584.00	2,640,205.00		167,814.00	0.00
25	State Franchise	Franchise Tax	KY		240,585.00	0.00	0.00	0.00		240,585.00	0.00
26	Ohio CAT Tax	Other State Tax	OH		0.00	0.00	19.00	19.00		0.00	0.00
27	Utility Gr Lic - EDP	Other State Tax	KY		1,710.00	0.00	19,792.00	19,853.00		1,649.00	0.00
28	WV Business & Occupation	Other Property Tax	WV		535,646.00	0.00	7,350,043.00	7,271,552.00		614,137.00	0.00
29	Muni License Fee	Other Taxes and Fees	KY		0.00	0.00	0.00	25.00		(25.00)	0.00
30	Muni License Fee	Other Taxes and Fees	WV		0.00	0.00	0.00	20.00		(20.00)	0.00
40	TOTAL				48,910,684.00	360,628.00	28,204,180.00	33,668,907.00		43,482,953.00	397,624.00

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

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

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%									
4	7%									
5	10%		411.1		411.4					
8	TOTAL Electric (Enter Total of lines 2 thru 7)									
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL									

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

OTHER DEFERRED CREDITS (Account 253)

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

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

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

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

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

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	41,222,314	61,179	2,142,329				406			39,140,758
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	41,222,314	61,179	2,142,329				406			39,140,758
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	(a) OTHER	(16,015,430)					254	10,870	254	523,422	(15,502,878)
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	25,206,884	61,179	2,142,329				11,276		523,422	23,637,880
18	Classification of TOTAL										
19	Federal Income Tax	25,206,884	61,179	2,142,329				10,870		523,016	23,637,880
20	State Income Tax										
21	Local Income Tax										

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

FOOTNOTE DATA

(a) Concept: DescriptionOfAcceleratedAmortizationPropertyOtherUtilityOther

232,561,566

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

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

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

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

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

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

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Line 6 Footnote

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

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

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

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

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

NOTES

Page 276-277

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

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

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

OTHER REGULATORY LIABILITIES (Account 254)

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

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

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

Electric Operating Revenues

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

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

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

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

FOOTNOTE DATA

(a) Concept: SalesToUltimateConsumers

Detail of Unmetered Sales - 2024

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

(b) Concept: OtherElectricRevenue

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

(c) Concept: SalesToUltimateConsumers

Detail of Unmetered Sales - 2023

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

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

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
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40					
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: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

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

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

SALES OF ELECTRICITY BY RATE SCHEDULES

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

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

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

SALES OF ELECTRICITY BY RATE SCHEDULES

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

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

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

SALES OF ELECTRICITY BY RATE SCHEDULES

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

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

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

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
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38						
39						
40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		6,446,586			

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

SALES OF ELECTRICITY BY RATE SCHEDULES

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

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

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

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
1	CITY OF OLIVE HILL	RQ	KPCO 52				20,952	533,941	1,710,836		2,244,777
2	CITY OF VANCEBURG	RQ	KPCO 51				53,472	1,294,489	3,648,102		4,942,591
3	PJM INTERCONNECTION	OS	NOTE 1				390,792	(72,041)	19,320,362		19,248,321
4	PJM INTERCONNECTION	RQ	NOTE 1				0			(2,566,487)	(2,566,487)
5	RBC CAPITAL MARKET, LLC	OS	NOTE 1				0		(399)		(399)
6	WELLS FARGO SECURITIES, LLC	OS	NOTE 1				0		(6,472)		(6,472)
15	Subtotal - RQ						74,424	1,828,430	5,358,938	(2,566,487)	4,620,881
16	Subtotal-Non-RQ						390,792	(72,041)	19,313,491		19,241,450
17	Total						465,216	1,756,389	24,672,429	(2,566,487)	23,862,331

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

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	4,426,925	5,403,024
5	(501) Fuel	135,378,424	114,274,670
6	(502) Steam Expenses	5,053,243	5,480,809
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	44,420	33,158
10	(506) Miscellaneous Steam Power Expenses	6,265,855	5,758,190
11	(507) Rents		
12	(509) Allowances	81,225	26,724
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	151,250,092	130,976,575
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,677,430	1,620,359
16	(511) Maintenance of Structures	1,794,464	1,932,042
17	(512) Maintenance of Boiler Plant	13,481,479	12,368,273
18	(513) Maintenance of Electric Plant	3,949,152	3,879,179
19	(514) Maintenance of Miscellaneous Steam Plant	1,535,471	1,688,834
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	22,437,996	21,488,687
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	173,688,088	152,465,262
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of Lines 62 thru 67)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	107,599,231	118,405,459
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	69,875	50,367
78	(557) Other Expenses	799,007	766,317
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	108,468,113	119,222,143
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	282,156,201	271,687,405
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,064,772	2,871,391
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	386,085	324,596
87	(561.3) Load Dispatch-Transmission Service and Scheduling	130	
88	(561.4) Scheduling, System Control and Dispatch Services	1,396,897	1,368,435
89	(561.5) Reliability, Planning and Standards Development	78,081	69,826
90	(561.6) Transmission Service Studies		(1)
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	452,211	369,553
93	(562) Station Expenses	203,497	260,205
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	27,183	22,203
95	(564) Underground Lines Expenses	16	12,130
96	(565) Transmission of Electricity by Others	78,574,635	68,473,837
97	(566) Miscellaneous Transmission Expenses	2,447,476	(22,553,468)
98	(567) Rents		
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	85,630,983	51,218,707
100	Maintenance		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
101	(568) Maintenance Supervision and Engineering	22,224	2,604
102	(569) Maintenance of Structures	32,286	7,201
103	(569.1) Maintenance of Computer Hardware	7,901	9,712
104	(569.2) Maintenance of Computer Software	223,926	192,357
105	(569.3) Maintenance of Communication Equipment	7,739	6,442
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	461,398	994,975
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	5,005,477	5,486,423
109	(572) Maintenance of Underground Lines	316	662
110	(573) Maintenance of Miscellaneous Transmission Plant	2,918	1,608
111	TOTAL Maintenance (Total of Lines 101 thru 110)	5,764,185	6,701,984
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	91,395,168	57,920,691
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	1,442,994	1,049,964
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,442,994	1,049,964
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	1,442,994	1,049,964
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,192,931	873,874
135	(581) Load Dispatching	1,048	1,968
136	(582) Station Expenses	387,429	325,489
137	(583) Overhead Line Expenses	281,948	469,217
138	(584) Underground Line Expenses	326,743	260,153
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	40,246	59,168
140	(586) Meter Expenses	1,353,435	1,211,647
141	(587) Customer Installations Expenses	191,956	222,454
142	(588) Miscellaneous Expenses	6,285,823	3,337,241
143	(589) Rents	1,048,358	796,344
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	11,109,917	7,557,555
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	15,594	18,724
147	(591) Maintenance of Structures	10,318	3,288
148	(592) Maintenance of Station Equipment	888,071	784,295
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	31,281,486	32,117,233
150	(594) Maintenance of Underground Lines	24,176	24,053
151	(595) Maintenance of Line Transformers	16,734	33,838
152	(596) Maintenance of Street Lighting and Signal Systems	9,850	24,697

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
153	(597) Maintenance of Meters	37,643	34,288
154	(598) Maintenance of Miscellaneous Distribution Plant	27,046	20,915
155	TOTAL Maintenance (Total of Lines 146 thru 154)	32,310,918	33,061,331
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	43,420,834	40,618,886
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	13,540	14,777
160	(902) Meter Reading Expenses	346,932	374,993
161	(903) Customer Records and Collection Expenses	4,846,162	4,915,009
162	(904) Uncollectible Accounts	20,263	473,357
163	(905) Miscellaneous Customer Accounts Expenses	19,916	43,766
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	5,246,813	5,821,902
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	51,153	22,327
168	(908) Customer Assistance Expenses	1,687,407	1,510,068
169	(909) Informational and Instructional Expenses		85,427
170	(910) Miscellaneous Customer Service and Informational Expenses	14,382	15,669
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	1,752,942	1,633,491
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	11,031	12,959
176	(913) Advertising Expenses	80	
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	11,111	12,959
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	12,245,270	11,303,490
182	(921) Office Supplies and Expenses	516,549	566,140
183	(Less) (922) Administrative Expenses Transferred-Credit	1,824,875	1,366,972
184	(923) Outside Services Employed	6,729,133	1,233,190
185	(924) Property Insurance	[(a)]1,092,472	1,191,497
186	(925) Injuries and Damages	2,264,769	(971,070)
187	(926) Employee Pensions and Benefits	127,663	(3,099,483)
188	(927) Franchise Requirements	162,329	140,462
189	(928) Regulatory Commission Expenses	3,992,821	3,801,736
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	119,861	134,748
192	(930.2) Miscellaneous General Expenses	760,593	480,603
193	(931) Rents	69,999	45,246
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	26,256,584	13,459,587
195	Maintenance		
196	(935) Maintenance of General Plant	3,157,747	2,921,334
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	29,414,331	16,380,921
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	454,840,394	395,126,219
	Page 320-323		

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

FOOTNOTE DATA

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

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

PURCHASED POWER (Account 555)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

FOOTNOTE DATA

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

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

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
44					
45					
46					
47					
48					
49					
40	TOTAL				

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

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

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

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

FOOTNOTE DATA

(a) Concept: OtherChargesTransmissionOfElectricityByOthers

Concurrent Energy Charges from East Kentucky Power.

(b) Concept: OtherChargesTransmissionOfElectricityByOthers

Transmission Enhancement Charges and Credits (PJM OATT Schedule 12)

(c) Concept: OtherChargesTransmissionOfElectricityByOthers

Transmission Owner Charges and Credits (PJM OATT Tariff Sixth Revised Volume No. 1)

(d) Concept: OtherChargesTransmissionOfElectricityByOthers

)

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

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	149,147
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	626
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Asociated Business Development	378,116
7	AEP Service Corporation Billings	93,835
8	Intercompany Allocations	14,023
9	Corporate Money Pool Allocations	35,491
10	Corporate and Fiscal	88,455
11	Miscellaneous	900
46	TOTAL	760,593

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

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

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

A. Summary of Depreciation and Amortization Charges

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

B. Basis for Amortization Charges

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

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM -- COAL/LIGNITE						
13	311 - Big Sandy	24.579					
14	311 - Mitchell	77.548					
15	312 - Big Sandy	77.874					
16	312 - Mitchell	884.471					
17	312 - Mitchell SCR	9.345					
18	314 - Big Sandy	64.17					
19	314 - Mitchell	56.654					
20	315 - Big Sandy	8.217					
21	315 - Mitchell	26.378					
22	316 - Big Sandy	4.345					
23	316 - Mitchell	9.933					
24	TOTAL COAL/LIGNITE	1,243.514					
25	TRANSMISSION						
26	350.1	35.72					
27	352	26.379					
28	352 - Big Sandy	0.01					
29	352 - Mitchell	0.072					
30	353	283.781					
31	353 - Big Sandy	0.603					
32	353 - Mitchell	12.303					
33	353.16	7.318					
34	354	103.118					
35	355	233.413					
36	356	169.089					
37	356.16	5.15					
38	357	5.173					
39	358	0.106					
40	358.16	0.393					
41	TOTAL TRANSMISSION	882.628					
42	DISTRIBUTION						
43	360.1	6.5					
44	361	14.868					
45	362	153.374					
46	362.16	4.521					
47	364	327.553					
48	365	337.751					
49	366	10.127					
50	367	13.357					
51	368	169.466					
52	369	78.904					
53	370	25.621					
54	371	20.72					
55	373	5.62					
56	TOTAL DISTRIBUTION	1,168.382					
57	GENERAL PLANT						
58	389.1	0.036					
59	390	28.728					
60	391	3.305					
61	391.11	0.495					
62	392	24.069					
63	393	0.43					

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
64	394	7.928					
65	395	0.226					
66	396	2.221					
67	397	44.852					
68	397.16	1.505					
69	398	2.197					
70	TOTAL GENERAL	115.992					
71	DEPRECIABLE SUM	[a]3,410.516					
Page 336-337							

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

FOOTNOTE DATA

(a) Concept: DepreciablePlantBase
The depreciable plant base is the November 30, 2024 total company depreciable plant.

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

REGULATORY COMMISSION EXPENSES

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

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

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

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:

   A. Electric R, D and D Performed Internally:
      1. Generation
         a. hydroelectric
            i. Recreation fish and wildlife
            ii. Other hydroelectric
         b. Fossil-fuel steam
         c. Internal combustion or gas turbine
         d. Nuclear
         e. Unconventional generation
         f. Siting and heat rejection
      2. Transmission
         a. Overhead
         b. Underground
      3. Distribution
      4. Regional Transmission and Market Operation
      5. Environment (other than equipment)
      6. Other (Classify and include items in excess of $50,000.)
      7. Total Cost Incurred

   B. Electric, R, D and D Performed Externally:
      1. Research Support to the electrical Research Council or the Electric Power Research Institute
      2. Research Support to Edison Electric Institute
      3. Research Support to Nuclear Power Groups
      4. Research Support to Others (Classify)
      5. Total Cost Incurred

3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

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

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

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	8,226,587		
4	Transmission	2,639		
5	Regional Market			
6	Distribution	5,944,368		
7	Customer Accounts	742,446		
8	Customer Service and Informational	287,960		
9	Sales			
10	Administrative and General	1,815,354		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	17,019,354		
12	Maintenance			
13	Production	4,507,003		
14	Transmission	2,222		
15	Regional Market			
16	Distribution	5,536,560		
17	Administrative and General	491,993		
18	TOTAL Maintenance (Total of lines 13 thru 17)	10,537,778		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	12,733,590		
21	Transmission (Enter Total of lines 4 and 14)	4,861		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	11,480,928		
24	Customer Accounts (Transcribe from line 7)	742,446		
25	Customer Service and Informational (Transcribe from line 8)	287,960		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	2,307,347		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	27,557,132	1,429,336	28,986,468
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	27,557,132	1,429,336	28,986,468
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	13,902,914	721,118	14,624,032
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	13,902,914	721,118	14,624,032
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,727,350	141,463	2,868,813
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,727,350	141,463	2,868,813
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	152 - Fuel Stock Undistributed			
80	154 - Materials and Supplies			
81	163 - Stores Expense Undistributed	938,354	(938,354)	
82	165 - Other Prepayments			
83	182 - Other Regulatory Assets			
84	183 - Prelim Survey	(1,186)	1,186	
85	184 - Clearing Accounts	1,354,749	(1,354,749)	
86	185 - ODD Temporary Facilities	51,600		51,600
87	186 - Misc Deferred Debits	1,071,561		1,071,561
88	402 - Maintenance Exp			
89	407 - Regulatory Debits			
90	417 - Misc Exp			
91	418 - Nonoperating Rental Income			
92	421 - Misc Nonoperating Income			
93	426 - Political Activities	23,691		23,691
94	451 - Misc Service Rev - Nonaffil			
95	456 - Other Electric Revenue			
95	TOTAL Other Accounts	3,438,769	(2,291,917)	1,146,852
96	TOTAL SALARIES AND WAGES	47,626,165		47,626,165

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

COMMON UTILITY PLANT AND EXPENSES

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

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

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

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

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

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	[a]0					
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						

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

FOOTNOTE DATA

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

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

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: 0									
1	January	(a) 0								
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total				0	0	0	0	0	0

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

FOOTNOTE DATA

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

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

Monthly ISO/RTO Transmission System Peak Load

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

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

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

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	5,321,277
3	Steam	3,146,375	23	Requirements Sales for Resale (See instruction 4, page 311.)	74,424
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	390,792
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other		27	Total Energy Losses	380,329
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	3,146,375	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	6,166,822
10	Purchases (other than for Energy Storage)	3,020,447			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	6,166,822			

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

MONTHLY PEAKS AND OUTPUT

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

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

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

Steam Electric Generating Plant Statistics

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

Line No.	Item (a)	Plant Name: 0	Plant Name: Big Sandy	Plant Name: Mitchell- Total	Plant Name: Mitchell-KEPCo Share [(a)]
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		STEAM	STEAM	STEAM
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		CONVENTIONAL	OUTDOOR BOILER	OUTDOOR BOILER
3	Year Originally Constructed		1963	1971	1971
4	Year Last Unit was Installed		2016	1971	1971
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)		280.50	1,633.00	817.00
6	Net Peak Demand on Plant - MW (60 minutes)		295	1,559	785
7	Plant Hours Connected to Load		6,472	7,039	7,039
8	Net Continuous Plant Capability (Megawatts)		0		0
9	When Not Limited by Condenser Water		295	1,560	780
10	When Limited by Condenser Water		295	1,560	780
11	Average Number of Employees		24	180	87
12	Net Generation, Exclusive of Plant Use - kWh		1,101,730,000	4,090,448,000	2,045,224,000
13	Cost of Plant: Land and Land Rights		1,761,182	7,014,102.00	3,224,928
14	Structures and Improvements		24,646,311	202,144,011.00	77,654,994
15	Equipment Costs		162,341,321	2,108,428,744.00	986,581,372
16	Asset Retirement Costs		6,618,088	39,372,388.00	18,222,854
17	Total cost (total 13 thru 20)		195,366,902	2,356,959,245	1,085,684,148
18	Cost per KW of Installed Capacity (line 17/5) Including		696.4952	1,443.3308	1,328.8668
19	Production Expenses: Oper, Supv, & Engr		1,988,630	4,337,119	2,438,294
20	Fuel		37,737,308	191,336,426	95,587,892
21	Coolants and Water (Nuclear Plants Only)		0		0
22	Steam Expenses		347	10,105,777	5,052,896
23	Steam From Other Sources		0		0
24	Steam Transferred (Cr)		0		0
25	Electric Expenses		0	88,837	44,419
26	Misc Steam (or Nuclear) Power Expenses		2,136,377	8,383,098	4,129,478
27	Rents		0		0
28	Allowances		33,670	47,880	47,556
29	Maintenance Supervision and Engineering		266,759	2,813,686	1,410,672
30	Maintenance of Structures		747,434	2,093,722	1,047,030
31	Maintenance of Boiler (or reactor) Plant		1,728,633	23,940,815	11,752,846
32	Maintenance of Electric Plant		1,288,003	5,295,973	2,661,150
33	Maintenance of Misc Steam (or Nuclear) Plant		618,346	1,834,205	917,125
34	Total Production Expenses	0	46,545,507	250,277,538	125,089,358
35	Expenses per Net kWh		0.0422	0.0612	0.0612

35	**Plant Name**	Big Sandy	Mitchell- Total	Mitchell- Total	Mitchell-KEPCo Share	Mitchell-KEPCo Share
36	Fuel Kind	Gas	Coal	Oil	Coal	Oil
37	Fuel Unit	Mcf	t	Boe	t	Boe
38	Quantity (Units) of Fuel Burned	9,564,007	1,805,085	65,970	902,543	32,985
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,196,000	12,378	138,411	12,378	138,411
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.522	91.117	109.113	91.117	109.113
41	Average Cost of Fuel per Unit Burned	3.621	95.061	113.061	95.061	113.061
42	Average Cost of Fuel Burned per Million BTU	3.027	3.840	19.449	3.840	19.449
43	Average Cost of Fuel Burned per kWh Net Gen	0.031	0.042	0.000	0.042	0.000
44	Average BTU per kWh Net Generation	10,232	11,011	0.000	11,011	0.000
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Name of Respondent: Kentucky Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

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

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

Hydroelectric Generating Plant Statistics

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

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

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

Pumped Storage Generating Plant Statistics

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	0
6	Plant Hours Connect to Load While Generating	0
7	Net Plant Capability (in megawatts)	0
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	0
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	**Cost of Plant**	
13	Land and Land Rights	
14	Structures and Improvements	0
15	Reservoirs, Dams, and Waterways	0
16	Water Wheels, Turbines, and Generators	0
17	Accessory Electric Equipment	0
18	Miscellaneous Powerplant Equipment	0
19	Roads, Railroads, and Bridges	0
20	Asset Retirement Costs	0
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	**Production Expenses**	
24	Operation Supervision and Engineering	0
25	Water for Power	0
26	Pumped Storage Expenses	0
27	Electric Expenses	0
28	Misc Pumped Storage Power generation Expenses	0
29	Rents	0
30	Maintenance Supervision and Engineering	0
31	Maintenance of Structures	0
32	Maintenance of Reservoirs, Dams, and Waterways	0
33	Maintenance of Electric Plant	0
34	Maintenance of Misc Pumped Storage Plant	0
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

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

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
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Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
42													
43													
44													
45													
46													
Page 410-411													

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

ENERGY STORAGE OPERATIONS (Large Plants)

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

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

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

ENERGY STORAGE OPERATIONS (Small Plants)

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

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR				
					Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
1	TOTAL			0	0	0	0	0	0
36	TOTAL			0	0	0	0	0	0

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

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	0700 BIG SANDY, KY	AMOS WV	765.00	765.00	3	0.13	0	1	954 MCMA			
2	0701 BIG SANDY, KY	SARGENTS, OH	765.00	765.00	3	24.20	0	1	954 MCMA			
3	0701 BIG SANDY, KY	SARGENTS, OH	765.00	765.00	3	4.79	0	1				
4	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	3	12.65	0	1	4-954 KCM ACSR			
5	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	3	3.04	0	1				
6	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	3	58.26	0	1				
7	0703 HANGING ROCK, OH	JEFFERSON, IN	765.00	765.00	3	154.74	0	1	1351.5 KCM ACSR			
8	0300 BIG SANDY, KY	TRI-STATE, WV	345.00	345.00	3	8.36	0	1	954 KCM ACSR			
9	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	1	0.33	0	1	500 KCM CU			
10	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	2	32.76	0	1	500 KCM CU			
11	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	3	0.06	0	1	795 KCM ACSR			
12	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	2	0.96	0	2	795 KCM ACSR			
13	0135 WOOTEN	ARNOLD DELVINTA (LGE)	161.00	161.00	1	1.09	0	1	795 KCM ACSR			
14	0136 WOOTEN EXTENSION		161.00	161.00	1	0.04	0	1	795 KCM ACSR			
15	0143 HAZARD	WOOTON	161.00	161.00	1	0.60	0	1	795 KCM ACSR			
16	0143 HAZARD	WOOTON	161.00	161.00	1	0.98	0	2	795 KCM ACSR			
17	0143 HAZARD	WOOTON	161.00	161.00	3	0.26	0	2	795 KCM ACSR			
18	0143 HAZARD	WOOTON	161.00	161.00	3	1.16	0	1	795 KCM ACSR			
19	0143 HAZARD	WOOTON	161.00	161.00	2	3.58	0	1	795 KCM ACSR			
20	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	3	12.08	0	1	2-556.5 KCM ACSR			
21	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	3	14.77	0	2	795 KCM ACSR			
22	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	0	0.00	0	0	2-556.5 KCM ACSR			
23	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	3	0.32	0	1	1272 ACSS			
24	0101 BIG SANDY, KY	W HUNTINGTON, WV	138.00	138.00	3	0.33	0	1	1033.5 KCM ACSR			
25	0102 BELLEFONTE, KY	N PROCTORVILLE, OH	138.00	138.00	3	0.81	0	2	795 KCM ACSR			
26	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	3	5.91	0	1	397.5 MCMCU			
27	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	3	23.25	0	1				
28	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	3	2.30	0	1	636 MCMA			
29	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	1	16.09	17	1				
30	0107 LOGAN, WV	SPRIGG, KY	138.00	138.00	3	0.48	0	2	397 MCMA			
31	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	1.48	0	1	954KCM ACSR			
32	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	3.31	0	1	795KCM ACSR			

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
33	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	3	30.88	0	1	636KCM ACSR			
34	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	22.86	0	1	636KCM ACSR			
35	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	1	0.01	0	1	636KCM ACSR			
36	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	3	0.71	14	1	795 MCMA			
37	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	1	0.38	0	1				
38	0113 CHADWICK	KY ELECTRIC STEEL	138.00	138.00	1	8.09	0	1	795 MCMA			
39	0115 CHADWICK	COALTON	138.00	138.00	1	0.98	0	1	795 MCMA			
40	0133 CHADWICK EXTENSION		138.00	138.00		1.06	0	1	795KCM ACSR			
41	0117 MILBROOK PARK, OH	FULLERTON	138.00	138.00	1	5.08	2	1	556.5 MCM			
42	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	1	25.83	0	1	795 MCMA			
43	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	3	0.63	0	0	1590 KCM			
44	0120 HATFIELD	SPRIGG	138.00	138.00	1	5.88	0	1	1033 MCM			
45	0121 HATFIELD	INEZ	138.00	138.00	1	14.67	0	1	1033.5 VAR			
46	0122 INEZ	LOVELY	138.00	138.00	1	6.86	0	1	1033.5 VAR			
47	0126 INEZ	MARTIKI	138.00	138.00	1	0.30	0	1	336.4 KCM ACSR			
48	0127 BIG SANDY	INEZ	138.00	138.00	3	25.08	0	1	795 MCMA			
49	0106 DORTON	FLEMING	138.00	138.00	1	6.85	0	1	795 MCMA			
50	0106 DORTON	FLEMING	138.00	138.00	3	0.83	0	0	795 MCMA			
51	0108 BEAVER CREEK	SPRIGG #1	138.00	138.00	1	32.60	0	1	397 MCMA			
52	0124 BIG SANDY	SOUTH NEAL	138.00	138.00	1	0.01	0	1	1033.5 VAR			
53	0109 BEAVER CREEK	SPRIGG #3	138.00	138.00		0.00	0	0				
54	0125 BELLEFONTE	AK STEEL OXYGEN PLANT	138.00	138.00	3	0.22	0	2	795 ACSR			
55	0130 JOHNS CREEK	SPRIGG	138.00	138.00	3	13.00	0	0	1033 MCM			
56	0131 BAKER	BIG SANDY EXT.	138.00	138.00	3	1.00	0	1	1351 KCM			
57	0131 BAKER	BIG SANDY EXT.	138.00	138.00	1	0.05	0	2	2 - 1351KCM ACSR			
58	0128 INEZ	JOHNS CREEK	138.00	138.00	3	17.00	0	0	2-556.5 MCM			
59	0129 BEAVER CREEK	JOHNS CREEK	138.00	138.00	3	22.25	0	2	1033.5KCM ACSR			
60	0132 GRANGSTON LOOP		138.00	138.00	3	0.84	0	2	556.5 KCM ACSR			
61	0137 HAYS BRANCH	MORGAN FORK	138.00	138.00	3	8.30	0	1	795 ACSR			
62	0138 SOFT SHELL	BEAVER CREEK	138.00	138.00	3	1.40	0	2	1590 ACSR			
63	0138 SOFT SHELL	SPICEWOOD	138.00	138.00	3	1.40	0	2	1590 ACSR			
64	0139 MORGAN FORK	BETSY LANE	138.00	138.00	3	0.10	0	1	795 ACSR			

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
65	0139 MORGAN FORK	BEAVER CREEK	138.00	138.00	3	0.10	0	1	795 ACSR			
66	0140 BONNYMAN	SOFT SHELL	138.00	138.00	3	0.88	0	2	1590 KCM ACSS			
67	0140 BONNYMAN	SOFT SHELL	138.00	138.00	1	19.15	0	1	1590 KCM ACSS			
68	0154 Racoon Extension		138.00	138.00	1	0.20	0	2	1033.5KCM ACSR			
69	0119 BETSY LAYNE	ALLEN	46.00	138.00	1	5.89	0	1	795KCM ACSR			
70	0119 BETSY LAYNE	ALLEN	46.00	138.00	3	0.22	0	2	1033.5KCM ACSR			
71	0119 BETSY LAYNE	ALLEN	46.00	138.00	1	0.33	0	2	1033.5KCM ACSR			
72	0142 STANVILLE EXTENSION		138.00	138.00	1	0.42	0	1	1033.5KCM ACSR			
73	0117 FULLERTON	MILLBROOK	69.00	138.00	1	(0.05)	0	1	556 KCM ACSR			
74	0160 INEZ	MARTIN COUNTY SOLAR NO. 1	138.00	138.00	1	0.04	0	1	795 KCM ACSS			
75	0144 WOOTON	STINNETT	161.00	161.00	3	2.17	0	1	795 KCM ACSR			
76	0144 WOOTON	STINNETT	161.00	161.00	1	0.06	0	1	795 KCM ACSR			
77	0144 WOOTON	STINNETT	161.00	161.00	2	2.15	0	1	795 KCM ACSR			
78	0149 KEWANEE 138KV EXTENSION		138.00	138.00	1	0.21	0	2	1033 KCM ACSR			
79	0149 KEWANEE 138KV EXTENSION		138.00	138.00	3	4.86	0	2	1033 KCM ACSR			
80	0146 LESLIE 161KV EXTENSION		161.00	161.00	3	0.31	0	0	795 KCM ACSR			
81	0136 WOOTON 161KV EXTENSION		161.00	161.00	1	(0.12)	0	1	795 KCM ACSR			
82	LINES < 132KV		69.00	69.00		594.43	6.03	0				
83	Line cost and expense are	not available by individual								42,315,711	551,839,853	594,155,564
84	transmission line	Total shown in Column j - p										
36	TOTAL					1,275.52	39.03	92		42,315,711.00	551,839,853.00	594,155,564.00

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

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

TRANSMISSION LINES ADDED DURING YEAR

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

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

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

SUBSTATIONS

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

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

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

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

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

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

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

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

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

FOOTNOTE DATA

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

NOT A NEW ISSUE - BOOK ENTRY ONLY

On June 26, 2014, Squire Patton Boggs (US) LLP, Bond Counsel, delivered its opinion that, under existing law (i) assuming continuing compliance with certain covenants and the accuracy of certain representations, interest on the Bonds would be excluded from gross income for federal income tax purposes, except interest on any Bond for any period during which it is held by a "substantial user" or a "related person," as those terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"), (ii) interest on the Bonds would be an item of tax preference under Section 57 of the Code for purposes of the federal alternative minimum tax imposed on individuals and corporations, and (iii) the Bonds, and all interest and income thereon, would be exempt from all taxation by the State of West Virginia and any county, municipality, political subdivision or agency thereof, except inheritance taxes. Interest on the Bonds may be subject to certain federal taxes imposed only on certain corporations. See TAX EXEMPTION. The form of such opinion is included in Appendix B-1 to this Reoffering Circular. Bond Counsel's opinion spoke only as of its date. In connection with the proposed change in interest rate Determination Method from the current Long-Term Interest Rate to a new Long-Term Interest Rate, Bond Counsel is rendering its opinion that such change will not, by itself, adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, and is permitted under the Act and by the Indenture. The proposed form of such opinion is included in Appendix B-2 to this Reoffering Circular. For further information, including information on the status of interest on the Bonds for purposes of the Federal alternative minimum tax under current law, see TAX EXEMPTION herein.

$65,000,000
West Virginia Economic Development Authority
Solid Waste Disposal Facilities Revenue Refunding Bonds
(Kentucky Power Company – Mitchell Project),
Series 2014A

Dated date: June 26, 2014 Due: April 1, 2036

The Series 2014A Bonds (the "Bonds") are limited obligations of the West Virginia Economic Development Authority (the "Issuer"), and do not constitute an indebtedness or a charge against the general credit of the Issuer or the State of West Virginia. The Bonds are payable solely from, and secured by a pledge of, the loan repayments under a note issued under the terms of a Loan Agreement (the "Agreement") between the Issuer and

KENTUCKY POWER COMPANY

Commencing June 20, 2023, the Bonds will bear interest at the rate of 4.70% per annum to, but not including, June 17, 2026, the date on which they are subject to mandatory tender for purchase. The failure to pay the purchase price on the mandatory tender date is an Event of Default under the Indenture. Interest on the Bonds will be payable semi-annually in arrears, commencing on December 1, 2023 and on each June 1 and December 1 of each year thereafter, and also the date on which the Bonds are subject to mandatory tender for purchase. Prior to June 17, 2026 the Bonds will not be subject to optional redemption but will be subject to extraordinary optional redemption and extraordinary mandatory redemption as described under *THE BONDS – Redemption*.

The Bonds will be reoffered as fully registered bonds and will be registered initially in the name of Cede & Co., as registered owner and nominee for The Depository Trust Company, New York, New York ("DTC"). DTC acts as a securities depository for the Bonds. The Bonds will be issued in denominations of $5,000 or any integral multiple thereof. Except under the limited circumstances described herein, Beneficial Owners of book-entry interests in the Bonds will not receive certificates representing their ownership interests. Payments of principal or purchase price of and premium, if any, and interest on the Bonds will be made through DTC and disbursements of such payments to Beneficial Owners will be the responsibility of DTC and its Participants (see *THE BONDS – Book-Entry Only System* herein). KeyBanc Capital Markets Inc. (the "Remarketing Agent") will act as the remarketing agent for the Company and reoffer the Bonds. The Bank of New York Mellon Trust Company, N.A. will act as Trustee for the Bonds.

PRICE: 100%

This cover page contains limited information for quick reference only and is not a summary of this Reoffering Circular. Investors should read the entire Reoffering Circular to obtain information essential to the making of an informed investment decision.

The Bonds are reoffered by the Remarketing Agent subject to the receipt of an opinion of Squire Patton Boggs (US) LLP, as described herein, and certain other conditions. Certain legal matters, other than the validity of the Bonds and the exclusion from gross income for Federal income tax purposes of interest thereon, will be passed on for the Remarketing Agent by its counsel, Hunton Andrews Kurth LLP, New York, New York, and for the Company by its internal counsel. Delivery of the Bonds in book-entry-only form is expected on or about June 20, 2023, through the facilities of DTC in New York, New York, against payment therefor.

KeyBanc Capital Markets

Dated: June 1, 2023

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No person has been authorized to give any information or to make any representations other than those contained in this Reoffering Circular in connection with the offer made hereby and, if given or made, such information or representations must not be relied upon as having been authorized by the Issuer, the Company or the Remarketing Agent. Neither the delivery of this Reoffering Circular nor any sale hereunder shall under any circumstances create any implication that there has been no change in the affairs of the Issuer or the Company since the date hereof. This Reoffering Circular does not constitute an offer or solicitation in any jurisdiction in which such offer or solicitation is not authorized, or in which the person making such offer or solicitation is not qualified to do so or to any person to whom it is unlawful to make such offer or solicitation. The Issuer neither has nor assumes any responsibility as to the accuracy or completeness of the information in this Reoffering Circular, all of which has been furnished by others, other than information under *THE ISSUER*.

The Remarketing Agent has provided the following sentence for inclusion in this Reoffering Circular. The Remarketing Agent has reviewed the information in this Reoffering Circular in accordance with, and as a part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Remarketing Agent does not guarantee the accuracy or completeness of such information. This Reoffering Circular is submitted in connection with the sale of the securities referenced herein, and may not be reproduced or be used, in whole or in part, for any other purpose. The delivery of this Reoffering Circular at any time does not imply that the information is correct as of any time subsequent to its date.

CERTAIN PERSONS PARTICIPATING IN THIS REOFFERING MAY ENGAGE IN TRANSACTIONS THAT STABILIZE, MAINTAIN OR OTHERWISE AFFECT THE PRICE OF THE BONDS, INCLUDING ENTERING STABILIZING BIDS. FOR A DESCRIPTION OF THESE ACTIVITIES, SEE *REMARKETING* HEREIN.

IN MAKING AN INVESTMENT DECISION, INVESTORS MUST RELY ON THEIR OWN EXAMINATION OF THE ISSUER, THE COMPANY AND THE TERMS OF THE OFFERING, INCLUDING THE MERITS AND RISKS INVOLVED, AND MAKE AN INDEPENDENT DECISION WHETHER THE OFFERING MEETS THE INVESTOR'S INVESTMENT OBJECTIVES AND FINANCIAL RISK TOLERANCE. THESE SECURITIES HAVE NOT BEEN APPROVED, DISAPPROVED, ENDORSED OR RECOMMENDED BY ANY FEDERAL OR STATE SECURITIES COMMISSION OR REGULATORY AUTHORITY. FURTHERMORE, THE FOREGOING AUTHORITIES, INCLUDING, WITHOUT LIMITATION, THE WEST VIRGINIA SECURITIES COMMISSION, HAVE NOT REVIEWED THIS REOFFERING CIRCULAR OR CONFIRMED THE ACCURACY OR TRUTHFULNESS OR DETERMINED THE ADEQUACY OF THIS REOFFERING CIRCULAR. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE. THE ISSUER IS RELYING ON AN EXEMPTION FROM REGISTRATION BY QUALIFICATION UNDER THE WEST VIRGINIA SECURITIES ACT. IMPORTANT RISK FACTORS ARE EXPLAINED IN APPENDIX A UNDER "RISK FACTORS."

$65,000,000
West Virginia Economic Development Authority
Solid Waste Disposal Facilities Revenue Refunding Bonds
(Kentucky Power Company - Mitchell Project),
Series 2014A

INTRODUCTORY STATEMENT

This Reoffering Circular, including the Appendices hereto, is provided to furnish certain information in connection with the reoffering by the West Virginia Economic Development Authority, a body politic and corporate of the State of West Virginia ("Issuer") of its Solid Waste Disposal Facilities Revenue Refunding Bonds (Kentucky Power Company - Mitchell Project) Series 2014A, in the aggregate principal amount of $65,000,000 (the "Bonds"). The Issuer neither has nor assumes any responsibility as to the accuracy or completeness of the information in this Reoffering Circular, all of which has been furnished by others, other than the information pertaining to the Issuer under *THE ISSUER*.

The Bonds were issued under and pursuant to a resolution of the Issuer adopted on March 20, 2014 ("Resolution") and an Indenture of Trust, dated as of June 15, 2014, as heretofore supplemented and amended ("Indenture"), between the Issuer and The Bank of New York Mellon Trust Company, N.A., as trustee (in such capacity, the "Trustee"). Capitalized terms used herein and not otherwise defined shall have the meanings given to them in the Indenture.

Pursuant to a Loan Agreement, dated as of June 15, 2014 ("Agreement"), between the Issuer and Kentucky Power Company ("Company"), the Issuer loaned to the Company the proceeds of the Bonds to be used to provide funds to refund or to pay at redemption the Issuer's Solid Waste Disposal Facilities Revenue Refunding Bonds (Ohio Power Company – Mitchell Project) Series 2008A, the proceeds of which having been used to provide funds to finance the cost of acquisition, construction and improvement of solid waste disposal facilities (the "Project"), or portions thereof, designed for the disposal of solid waste at the Mitchell Generating Station located near Moundsville, West Virginia (the "Plant").

In order to evidence the loan from the Issuer (the "Loan") and to provide for its repayment, the Company issued a nonnegotiable promissory note (the "Note") pursuant to the Agreement. Payments required under the Note will be sufficient, together with any other funds on deposit in the Bond Fund (hereinafter described) under the Indenture, to pay the principal of and premium, if any, and interest on the Bonds and to make or provide for payments to the Trustee equal to 100% of the principal amount of the Bonds plus accrued interest, if any, upon tender thereof ("Purchase Price"). The Bonds are not otherwise secured by a mortgage on, or security interest in, any of the Project or any other property of the Company.

The Bonds are special obligations of the Issuer, and are paid solely from, and are secured by a pledge of, payments to be made to the Issuer under the terms of the Agreement. See *THE BONDS – Security*.

The Bonds will mature and become due and payable, together with any accrued and unpaid interest, on April 1, 2036. The Bonds will bear interest for a Long-Term Interest Rate Period at the rate of 4.70% per year, from June 20, 2023 to, but not including, June 17, 2026. Interest on

the Bonds will be payable semi-annually in arrears, commencing on December 1, 2023 and on each June 1 and December 1 of each year thereafter, and also the date on which the Bonds are subject to mandatory tender for purchase. The Bonds are subject to mandatory tender for purchase on June 17, 2026. The failure to pay the purchase price on the mandatory tender date is an Event of Default under the Indenture.

The Bonds will be issued in authorized denominations of $5,000 or any integral multiple thereof and are held by The Depository Trust Company ("DTC"), or its nominee, as securities depository with respect to the Bonds. See *THE BONDS – Book-Entry Only System*.

Brief descriptions of the Issuer, the Project, the Bonds, the Agreement and the Indenture are included in this Reoffering Circular. Information regarding the business, properties and financial condition of the Company is included or incorporated by reference in Appendix A attached hereto. The form of opinion Bond Counsel delivered upon the original issuance of the Bonds is set forth in Appendix B-1 hereto and the proposed form of opinion to be delivered by Bond Counsel upon conversion of the interest rate on the Bonds is set forth in Appendix B-2 hereto. The descriptions herein of the Agreement and the Indenture are qualified in their entirety by reference to such documents, and the description herein of the Bonds is qualified in its entirety by reference to the form thereof and the information with respect thereto included in the aforesaid documents. All such descriptions are further qualified in their entirety by reference to laws and principles of equity relating to or affecting generally the enforcement of creditors' rights. Copies of such documents may be obtained from the Company.

This Reoffering Circular describes the Bonds only while the Bonds are in the Long-Term Interest Rate Period commencing June 20, 2023 and ending June 17, 2026.

THE ISSUER

The West Virginia Economic Development Authority, empowered and authorized pursuant to Chapter 31, Article 15, Section 1, et. seq. of the Code of West Virginia, 1931, as amended (the "Act"), is a body corporate and politic, constituting a public corporation and government instrumentality of the State of West Virginia, with the power to borrow money and issue its bonds and other debt instruments for any of its purposes, and to finance making loans to finance any project to private corporations. Such projects include solid waste disposal facilities. The Issuer has no taxing power.

THE BONDS SHALL NOT CONSTITUTE A DEBT OR A PLEDGE OF THE FAITH AND CREDIT OR TAXING POWER OF THE STATE OF WEST VIRGINIA OR OF ANY COUNTY, MUNICIPALITY OR ANY OTHER POLITICAL SUBDIVISION OF THE STATE OF WEST VIRGINIA, AND THE HOLDERS AND OWNERS THEREOF SHALL HAVE NO RIGHT TO HAVE TAXES LEVIED BY THE LEGISLATURE OF THE STATE OF WEST VIRGINIA OR THE TAXING AUTHORITY OF ANY COUNTY, MUNICIPALITY OR ANY OTHER POLITICAL SUBDIVISION OF THE STATE OF WEST VIRGINIA FOR THE PAYMENT OF THE PRINCIPAL OF, INTEREST ON OR PURCHASE PRICE OF THE BONDS, BUT SHALL BE PAYABLE SOLELY FROM REVENUES AND FUNDS PLEDGED FOR ITS PAYMENT AS AUTHORIZED BY THE ACT.

THE PROJECT

The Project consists of various systems which are designed for the disposal of solid wastes resulting from the operation of the Plant. The solid waste disposal facilities are comprised of the portion of the flue gas desulfurization system (the "FGD System") constructed with respect to the two 800 megawatt units at the Plant that relates to the disposal of solid waste generated as part of the FGD System.

THE BONDS

General

The Bonds were issued in fully registered form only in the aggregate amount set forth on the cover page hereof. The Bonds are dated as of their date of issuance and bear interest from such date. The Bonds will mature and become due and payable, together with any accrued and unpaid interest, on April 1, 2036. For the period beginning June 20, 2023 to, but not including, June 17, 2026, the Bonds will bear interest at a Long-Term Interest Rate of 4.70% per annum. Interest on the Bonds will be payable semi-annually in arrears, commencing on December 1, 2023 and on each June 1 and December 1 of each year thereafter, and also the date on which the Bonds are subject to mandatory tender for purchase. The Bonds are subject to mandatory tender for purchase on June 17, 2026.

During the Long-Term Interest Rate Period commencing June 20, 2023 and ending June 17, 2026, the Company may not change the Interest Rate Determination Method. The Bonds may subsequently be converted to bear interest at a Daily Rate, Two-Day Rate, Weekly Rate, Commercial Paper Rate, Index-Based Rate, Auction Mode Rate or another Long-Term Interest Rate. THIS REOFFERING CIRCULAR DESCRIBES THE TERMS AND CONDITIONS OF THE BONDS, THE AGREEMENT AND THE INDENTURE ONLY WHILE THE BONDS ARE IN THE LONG-TERM INTEREST RATE PERIOD COMMENCING JUNE 20, 2023 AND ENDING JUNE 17, 2026.

Beneficial interests in the Bonds have been issued pursuant to a Book-Entry Only System ("Book-Entry Only System") maintained by The Depository Trust Company, New York, New York ("DTC"), as described below under the caption *Book-Entry Only System*. Under the Indenture, the Trustee and the Issuer may appoint a successor securities depository to DTC. (DTC, together with any such successor securities depository, is hereinafter referred to as the "Securities Depository"). The following information is subject in its entirety to the provisions described below under the caption *Book-Entry Only System* while the Bonds are in the Book-Entry Only System.

Form and Denomination of Bonds; Payments on the Bonds

General

The Bonds have been issued only as fully registered bonds, without coupons, in denominations of $5,000 or any integral multiple thereof. The Bonds are registered in the name of Cede & Co., as registered owner and nominee of DTC. DTC acts as securities depository for the Bonds and individual purchases of Bonds may be made in book-entry form only. So long as the Bonds are in book-entry only form, purchasers of Bonds will not receive certificates representing their interest in the Bonds purchased. So long as Cede & Co. is the registered owner of the Bonds, as nominee of DTC, references herein to the Bondholders or registered owners or holder shall mean Cede & Co., and shall not mean the Beneficial Owners (as defined below) of the Bonds.

So long as Cede & Co. is the registered owner of the Bonds, principal of, premium, if any, and interest on the Bonds are payable to Cede & Co., as nominee for DTC, which will, in turn, remit such amounts to the DTC Participants (as defined below) for subsequent disbursement to the Beneficial Owners. See – *Book-Entry Only System* below.

The Bank of New York Mellon Trust Company, N.A. has been appointed as Trustee under the Indenture. The designated office of the Trustee is located, initially, in New Albany, Ohio. The Company and its affiliates maintain banking relationships with The Bank of New York Mellon Trust Company, N.A. and its affiliates. The Bank of New York Mellon Trust Company, N.A. and its affiliates serve as trustee under various indentures with, or for the benefit of, the Company and its affiliates.

Neither the Issuer nor the Trustee shall be required to make any transfer or exchange of any Bond during the ten Business Days prior to the mailing of a notice of Bonds selected for redemption or, with respect to a Bond, after such Bond or any portion thereof has been selected for redemption. Registration of transfers and exchanges shall be made without charge to the Bondholders, except that any required taxes or other governmental charges shall be paid by the Bondholder requesting registration of transfer or exchange.

Interest

Each payment of interest shall include interest accrued through the day before such interest payment date. Interest on the Bonds will be computed on the basis of a 360-day year consisting of twelve 30-day months.

All payments of interest on the Bonds will be paid to the registered owner thereof whose name appears in the bond register kept by the Trustee as of the close of business on the Record Date (as defined below) by check mailed on the interest payment date, provided that any registered owner of $1,000,000 or more in aggregate principal amount of the Bonds may, upon written request given to the Trustee at least two Business Days (as defined below) prior to an interest payment date designating an account in a domestic bank, be paid by wire transfer of immediately available funds. If any payment on the Bonds is due on a non-Business Day, it will be made on the next Business Day and no interest will accrue as a result.

"Business Day" means any day other than a Saturday or Sunday or other than a day on which commercial banks in New York, New York or the city in which the designated corporate trust office of the Trustee is located are required or authorized by law to close or other than a day on which the New York Stock Exchange is closed.

"Record Date" means the fifteenth day of the calendar month preceding the relevant interest payment date.

Security

The Bonds are special obligations of the Issuer, the principal of and premium, if any, and interest on which are payable solely from, and secured by a pledge of, the Loan Payments to be made by the Company under the Agreement. In addition, the Company is obligated to pay the Purchase Price with respect to the Bonds. The pledge does not extend to funds to which the Trustee is entitled in its own right as fees, reimbursement, indemnity or otherwise. The Bonds are not secured by a mortgage or security interest in the Project or any other property of the Company.

Mandatory Tender

The Purchase Price will be payable upon mandatory tender of the Bonds on June 17, 2026. The Company is obligated to pay the Purchase Price of Bonds tendered to the extent that remarketing proceeds are not available to pay such Purchase Price. No other source of payment of such Purchase Price is being provided.

Redemption

The Bonds are subject to redemption as described below:

Optional Redemption. Except as described under the caption *Extraordinary Optional Redemption*, the Bonds are not redeemable at the option of the Issuer or the Company prior to June 17, 2026.

Extraordinary Optional Redemption. The Bonds are subject to redemption in whole or in part on any date at a redemption price equal to the aggregate principal amount of the outstanding Bonds plus accrued interest thereon to the redemption date, without premium, upon receipt by the Trustee of a direction from the Company stating that any of the following events has occurred:

(a) The Project or the Plant shall have been damaged or destroyed to such an extent that the Company deems it not practical or desirable to rebuild, repair or restore the Project or the Plant, as the case may be.

(b) Title to, or the temporary use of, all or a significant part of the Project or the Plant shall have been taken under the exercise of the power of eminent domain so as to render the Project unsatisfactory to the Company for its intended purpose.

(c) As a result of any changes in the Constitution of the State, the Constitution of the United States of America or any state or federal laws or as a result of legislative or administrative action (whether state or federal) or by final decree, judgment or order

of any court or administrative body (whether state or federal) entered after any contest thereof by the Issuer or the Company in good faith, the Agreement shall have become void or unenforceable or impossible of performance in accordance with the intent and purpose of the parties as expressed in the Agreement.

(d) Unreasonable burdens or excessive liabilities shall have been imposed upon the Issuer or the Company with respect to the Project or the Plant or the operation thereof, including, without limitation, the imposition of federal, state or other ad valorem, property, income or other taxes not being imposed on the date of the Agreement.

(e) Changes in the economic availability of raw materials, operating supplies, energy sources or supplies or facilities (including, but not limited to, facilities in connection with the disposal of industrial wastes) necessary for the operation of the Project or the Plant occur or technological or other changes occur which in the Company's reasonable judgment render the Project or the Plant uneconomic or obsolete.

(f) Any court or administrative body shall enter a judgment, order or decree, or shall take administrative action, requiring the Company to cease all or any substantial part of its operations served by the Project or the Plant to such extent that the Company is or will be prevented from carrying on its normal operations at the Project or the Plant for a period of six consecutive months.

(g) The termination by the Company of operations at the Plant.

Extraordinary Mandatory Redemption. The Bonds are subject to mandatory redemption at any time, in whole, or in part if such partial redemption will preserve the exemption from federal income taxation of interest on the remaining outstanding Bonds, at a redemption price equal to the principal amount thereof together with unpaid interest accrued to the date fixed for redemption, and without premium, if (a) a final decree or judgment of any federal court, in which the Company participates to the extent it deems sufficient, or (b) a final action by the Internal Revenue Service, in proceedings in which the Company participates to the extent it deems sufficient, determines that the interest paid or payable on Bonds to a person, other than, as provided in Section 147(a) of the Code, a "substantial user" of the Project or a "related person", is or was includable in the gross income of the owner thereof for federal income tax purposes under the Code, as a result of the failure by the Company to observe or perform any covenant, condition or agreement on its part to be observed or performed under the Agreement or the inaccuracy of any representation by the Company under the Agreement or receipt by the Company of an Opinion of Tax Counsel to such effect obtained by the Company and rendered at the request of the Company; provided, however, that no decree or judgment by any court or action by the Internal Revenue Service shall be considered final unless the Bondholder or Beneficial Owner involved in such proceeding or action (i) gives the Company and the Trustee prompt written notice of the commencement thereof and (ii) if the Company agrees to pay all expenses in connection therewith and to indemnify such Bondholder or Beneficial Owner against all liabilities in connection therewith, offers the Company the opportunity to control the defense thereof. Any such redemption shall be made on a date determined by the Trustee not more than 180 days after the date of such final decree, judgment or

action. The Trustee shall give the Issuer and the Company not less than 45 days written notice of such date.

Notice of Redemption. At least 30 days before each redemption, the Trustee will mail a notice of redemption by first-class mail to each Bondholder with Bonds to be redeemed at such holder's registered address. Failure to give any required notice of redemption as to any particular Bonds, or any defect therein, will not affect the validity of the call for redemption of any Bonds in respect of which no failure or defect occurs. Any notice mailed as provided in this paragraph shall be effective when sent and will be conclusively presumed to have been given whether or not actually received by the addressee.

The notice shall identify the Bonds to be redeemed and shall state (1) the redemption date (and, if the Bonds provide that accrued interest will not be paid on the redemption date, the date it will be paid), (2) the redemption price, (3) that the Bonds called for redemption must be surrendered to collect the redemption price, (4) the address at which the Bonds must be surrendered and (5) that interest on the Bonds called for redemption ceases to accrue on the redemption date.

With respect to an optional redemption of any Bonds, unless moneys sufficient to pay the principal of, premium, if any, and interest on the Bonds to be redeemed shall have been received by the Trustee prior to the giving of such notice of redemption, such notice may state that said redemption shall be conditional upon the receipt of such moneys by the Trustee on or prior to the date fixed for redemption. If such moneys are not received, such notice shall be of no force and effect, the Issuer shall not redeem such Bonds, the redemption price shall not be due and payable and the Trustee shall give notice, in the same manner in which the notice of redemption was given, that such moneys were not so received and that such Bonds will not be redeemed.

When notice is required and given, Bonds called for redemption become due and payable on the redemption date; in such case when funds are deposited with the Trustee sufficient for redemption, interest on the Bonds to be redeemed ceases to accrue as of the date of redemption.

Book-Entry Only System

DTC, the world's largest securities depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934, as amended. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments (from over 100 countries) that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing

Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). The DTC Rules applicable to its Participants are on file with the SEC. More information about DTC can be found at www.dtcc.com. The contents of such website do not constitute a part of this Reoffering Circular.

Purchases of Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Bonds on DTC's records. The ownership interest of each actual purchaser of each Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in Bonds, except in the event that use of the book-entry system for the Bonds is discontinued.

To facilitate subsequent transfers, all Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners of Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the Bonds, such as redemptions, tenders, defaults, and proposed amendments to the Bonds documents. For example, Beneficial Owners of Bonds may wish to ascertain that the nominee holding the Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners. In the alternative, Beneficial Owners may wish to provide their names and addresses to the registrar and request that copies of notices be provided directly to them.

Redemption notices shall be sent to DTC. If less than all of the Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such issue to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Bonds unless authorized by a Direct Participant in accordance with DTC's MMI Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to us as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct

Participants to whose accounts the Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Redemption proceeds and distributions on the Bonds will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from us or the Trustee on the payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with Bonds held for the accounts of customers in bearer form or registered in "street name", and will be the responsibility of such Participant and not of DTC, the Trustee or us, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds and distributions to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is our responsibility, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

A Beneficial Owner shall give notice to elect to have its Bonds purchased or tendered, through its Participant, to the Tender/Remarketing Agent, and shall effect delivery of such Bonds by causing the Direct Participant to transfer the Participant's interest in the Bonds, on DTC's records, to the Tender/Remarketing Agent. The requirement for physical delivery of the Bonds in connection with an optional tender or a mandatory purchase will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on DTC's records and followed by a book-entry credit of tendered Bonds to the Tender/Remarketing Agent's DTC account.

DTC may discontinue providing its services as depository with respect to the Bonds at any time by giving reasonable notice to the Issuer or the Trustee. Under such circumstances, in the event that a successor depository is not obtained, Bond certificates are required to be printed and delivered.

The Issuer may decide to discontinue use of the system of book-entry only transfers through DTC (or a successor securities depository). In that event, Bond certificates will be printed and delivered to DTC.

The information in this section concerning DTC and DTC's book-entry system has been obtained from sources that the Issuer, the Company, the Trustee and the Remarketing Agent believe to be reliable, but none of the Issuer, the Company, the Trustee or the Remarketing Agent take responsibility for the accuracy thereof.

NONE OF THE ISSUER, THE COMPANY, THE TRUSTEE OR THE REMARKETING AGENT (OTHER THAN IN ITS CAPACITY, IF ANY, AS A DIRECT PARTICIPANT OR INDIRECT PARTICIPANT) WILL HAVE ANY RESPONSIBILITY OR OBLIGATION TO SUCH DIRECT PARTICIPANTS OR INDIRECT PARTICIPANTS, OR THE PERSONS FOR WHOM THEY ACT AS NOMINEES, WITH RESPECT TO THE PAYMENTS TO OR THE PROVIDING OF NOTICE FOR THE DIRECT PARTICIPANTS, THE INDIRECT PARTICIPANTS, OR THE BENEFICIAL OWNERS OF THE CERTIFICATES.

THE AGREEMENT

In addition to the description of certain provisions of the Agreement contained elsewhere herein, the following is a brief summary of certain provisions of the Agreement and does not purport to be comprehensive or definitive. All references herein to the Agreement are qualified in their entirety by reference to the Agreement for the detailed provisions thereof.

Use of Bond Proceeds

The Issuer loaned the proceeds of the original sale of the Bonds to the Company in accordance with the Agreement and the Indenture.

Repayment of Loan

In order to evidence the Loan and the Company's obligation to repay the same, the Company issued the Note in the same principal amount as the Bonds and having the same stated maturity and interest rate. Pursuant to the Note, the Company will pay to the Trustee, as assignee of the Issuer, amounts to fund payments on the Bonds in such amounts which, together with other moneys available therefor in the Bond Fund or the Purchase Fund created under the Indenture, will be sufficient to pay when due the principal of, premium, if any, and interest on and Purchase Price for the outstanding Bonds as they shall mature, be redeemed, be purchased or deemed purchased or otherwise become due as provided in the Indenture.

The payment obligations of the Company under the Note are absolute and unconditional, and the Company will make such payments free of any deductions and without abatement, diminution or setoff. In the event that the Company fails to make any such payments, the payment so in default will continue as an obligation of the Company until the amount in default has been fully paid.

Other Payments Under The Agreement

In addition to the payments under the Note, the Company agreed to pay certain costs and expenses of the Issuer and the Trustee in connection with the Bonds and to indemnify such parties against certain liabilities arising in connection with the sale of the Bonds and the execution and delivery of the related bond documents.

Pledge

The Issuer assigned to the Trustee a security interest in all rights, title and interest in, to and under the Note and the Agreement and all amounts payable thereunder (except for certain payments under the Agreement in respect of indemnification and certain fees and expenses). The Company assented to such assignment and agreed that, as to the Trustee, its obligation to make payments will be absolute and not subject to any defense or any right of set-off, counterclaim or recoupment arising out of any breach by the Issuer or the Trustee of any obligation to the Company.

Corporate Existence

The Company will maintain its legal existence and will not sell its properties as an entirety or substantially as an entirety or consolidate with or merge into another entity or permit one or

more other entities to consolidate with or merge into it, unless the successor corporation or transferee resulting from any such consolidation, merger, sale or transfer shall assume all obligations of the Company arising under or contemplated by the Agreement, the Note and the Indenture. No further consolidation, merger or sale or other transfer shall be made except in compliance with those provisions.

Assignment of the Agreement

The Agreement may be assigned in whole or in part by the Company only with the consent of the Issuer, subject to the following conditions: (a) no assignment will relieve the Company from primary liability for any of its obligations under the Agreement; (b) any assignment by the Company must retain for the Company such rights and interests to permit it to perform its remaining obligations under the Agreement, and any assignee from the Company shall assume the obligations of the Company hereunder to the extent of the interest assigned; (c) the Company will, within 30 days after the execution thereof, furnish or cause to be furnished to the Issuer and the Trustee a true and complete copy of each assignment together with any instrument of assumption; and (d) any assignment from the Company will not materially impair fulfillment of the purposes of the Project to be accomplished by operation of the Project as provided in the Agreement.

Events of Default and Remedies

The Agreement provides that the occurrence of one or more of the following events will constitute an "Event of Default:"

(a) The failure to pay any Loan Payment, or pay any payment required to be made to pay the Purchase Price, when due;

(b) The occurrence of an Event of Default described in paragraph (a), (b) or (c) under *THE INDENTURE—Events of Defaults and Remedies*;

(c) Failure by the Company to observe and perform any other agreement, term or condition under the Agreement, other than such failure which will result in an event of default described in (a) or (b) above, which continues for a period of 90 days after notice to the Company by the Issuer or the Trustee or such longer period as the Issuer and the Trustee may agree to in writing; *provided* that the failure shall not constitute an Event of Default if the Company institutes curative action within the applicable period and diligently pursues that action to completion;

(d) Any representation or warranty under the Agreement shall not have been true in all material respects when made; and

(e) Certain events relating to bankruptcy, insolvency or reorganization of the Company.

A failure by the Company described in subparagraph (c) above is not a default under that subparagraph if it occurs by reason of certain courses, circumstances and events of force majeure specified in the Agreement that are not reasonably within the control of the Company.

Whenever any Event of Default under the Agreement has happened and is subsisting, the Issuer or the Trustee may take either or both of the following remedial steps:

(a) Inspect, examine and make copies of the books, records, accounts and financial data of the Company, only, however, insofar as they pertain to the Project; and

(b) Pursue all remedies to recover all amounts then due and thereafter to become due under the Agreement and the Note, or to enforce the performance and observance of any other obligation or agreement of the Company under those instruments.

Any amounts collected as Loan Payments or applicable to Loan Payments and any other amounts which would be applicable to payment of Bond Service Charges collected pursuant to action taken as provided above shall be paid into the Bond Fund and applied in accordance with the provisions of the Indenture or, if the outstanding Bonds have been paid and discharged in accordance with the provisions of the Indenture, shall be paid as provided in the Indenture for transfers of remaining amounts in the Bond Fund.

Certain Covenants Regarding Arbitrage and Tax Exemption

The Issuer and the Company have agreed not to knowingly take any action or omit to take any action, which would result in a loss of the exemption from federal income taxation of interest on the Bonds by virtue of the Bonds being considered "arbitrage bonds" within the meaning of Section 148 of the Code.

The Issuer and the Company have agreed that they will not take any action, cause any action to be taken, omit to take any action or cause any omission to occur which would cause the interest on the Bonds to become includable in gross income of the recipients thereof for purposes of federal income taxation.

Amendments to the Agreement

The Indenture provides that the Agreement may be amended without the consent of or notice to the owners of the Bonds only as may be required or permitted (i) by the provisions of the Agreement or the Indenture or for the purposes for which the Indenture may be amended or supplemented without the consent of the owners, (ii) for the purpose of curing any ambiguity or formal defect or omission in the Agreement or (iii) in connection with any other change therein which, in the judgment of the Trustee, is not to the prejudice of the Trustee or the owners of the Bonds. Any other amendments to the Agreement may be made only with the written approval or consent of the owners of not less than a majority in aggregate principal amount of the Bonds outstanding. An Opinion of Tax Counsel to the effect that such action is permitted under the Act and the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes (a "Favorable Opinion of Tax Counsel") is required for any amendment to the Agreement.

THE INDENTURE

In addition to the description of certain provisions of the Indenture contained elsewhere herein, the following is a brief summary of certain provisions of the Indenture and does not purport to be comprehensive or definitive. All references herein to the Indenture are qualified in their entirety by reference to the Indenture for the detailed provisions thereof.

Pledge and Security

Pursuant to the Indenture, the payments to be made by the Company under the Agreement and the Note have been assigned by the Issuer to the Trustee to secure the payment, when due, of the principal of, and premium, if any, and interest on, the Bonds. The Issuer has mortgaged, pledged and granted a security interest to the Trustee all right, title and interest of the Issuer in and to (i) the Revenues, including without limitation, all Loan Payments and all other amounts receivable by the Issuer under the Agreement in respect of repayment of the loan and (ii) the Note and the Agreement (except certain rights to the payment of its costs and expenses, to indemnification and to enforce certain covenants of the Company); provided, that the Trustee, in case of an acceleration of the Bonds, will have a prior claim on the Bond Fund for the payment of its compensation and expenses.

Bond Fund

Payments made by the Company under the Agreement with respect to the Bonds and certain other amounts specified in the Indenture will be deposited in the Bond Fund. The Trustee will apply money contained in the accounts described below maintained within the Bond Fund as follows:

(a) Interest Account. The Trustee, on each Interest Payment Date, will withdraw and apply from moneys on deposit in the Interest Account an amount sufficient to pay interest on the outstanding Bonds on such Interest Payment Date.

(b) Principal Account. The Trustee, on each Principal Payment Date (as defined in the Indenture), will withdraw and apply from moneys on deposit in the Principal Account, an amount equal to the principal becoming due on the Bonds on such Principal Payment Date (other than a redemption date). Money in such Principal Account will be used and withdrawn by the Trustee on each Principal Payment Date solely for the payment of the principal of outstanding Bonds.

(c) Redemption Account. The Trustee, on or before each redemption date, will withdraw and apply from moneys on deposit in the Redemption Account amounts required to pay the principal of and premium, if any, and accrued interest on Bonds to be redeemed prior to their stated maturity. Money in such Redemption Account will be used and withdrawn by the Trustee on each redemption date solely for the payment of the principal of and premium, if any, and accrued interest on outstanding Bonds upon the redemption thereof prior to their stated maturity.

Monies held in the Bond Fund shall be shall be invested and reinvested by the Trustee as provided in the Indenture, including, if directed by the Company, in Permitted Investments.

Purchase Fund

The Trustee will apply money contained in the accounts described below maintained within the Purchase Fund as follows:

Remarketing Proceeds Account. Upon receipt of the proceeds of a remarketing of Bonds on a purchase date, the Trustee will directly deposit such proceeds, and will deposit only such proceeds, in the Remarketing Proceeds Account for application to the Purchase Price of the Bonds. Neither the Issuer nor the Company will have any interest in the Remarketing Proceeds Account.

Company Purchase Account. Upon receipt of immediately available funds provided to the Trustee by the Company pursuant to the Indenture, the Trustee shall directly deposit such money, and shall deposit only such money, in the Company Purchase Account for application to the Purchase Price of the Bonds. Any amounts deposited in the Company Purchase Account and determined by the Trustee to be not needed with respect to any purchase date for the payment of the Purchase Price for any Bonds shall be promptly returned following such determination to the Company.

Events of Default and Remedies

The following events are Events of Default under the Indenture:

(a) Default in the due and punctual payment of interest on any Bond;

(b) Default in the due and punctual payment of the principal of, or premium, if any, on any Bond, whether at the stated maturity thereof, or upon unconditional proceedings for redemption thereof;

(c) Default in the due and punctual payment of the Purchase Price of any Bond required to be purchased in accordance with its terms;

(d) Default in the performance or observance of any other of the covenants, agreements or conditions on the part of the Issuer in the Indenture or in the Bonds, continuing 30 days after delivery of notice thereof; or

(e) The occurrence and continuance of an event of default under the Agreement as described under *THE AGREEMENT – Events of Default and Remedies.*

Upon the occurrence and continuance of an Event of Default above the Trustee may, and upon the written request of the owners of at least 25% in aggregate principal amount of the Bonds then outstanding shall, declare the principal of and accrued interest on the outstanding Bonds to be due and payable immediately. Upon any such declaration, the principal of and accrued interest on the outstanding Bonds shall be due and payable immediately.

The Trustee may rescind an acceleration of the Bonds and its consequences if (1) all payment defaults with respect to the Bonds have been cured and all reasonable fees and charges of the Trustee, including reasonable attorneys' fees, have been paid, and (2) the Bondholders have

not been notified of the acceleration. Except as provided above, the Trustee will not declare the Bonds to be due and payable.

If an Event of Default occurs and is continuing, the Trustee may pursue any available remedy by proceeding at law or in equity to collect the principal of and premium, if any, or interest on the Bonds or to enforce the performance of any provision of the Bonds or the Indenture.

A majority in aggregate principal amount of the outstanding Bonds by notice to the Trustee may waive an existing Event of Default and its consequences. When an Event of Default is waived, it is cured and stops continuing, but no such waiver will extend to any subsequent or other Event of Default or impair any right consequent to it.

The holders of a majority in aggregate principal amount of Bonds outstanding may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or of exercising any trust or power conferred on it.

An owner of a Bond may not pursue any remedy with respect to the Indenture or the Bonds unless (a) the owner gives the Trustee notice stating that an Event of Default is continuing, (b) the owners of at least 25% in aggregate principal amount of the outstanding Bonds make a written request to the Trustee to pursue the remedy, (c) such owner or owners offer to the Trustee indemnity satisfactory to the Trustee against any loss, liability or expense, and (d) the Trustee does not comply with the request within 60 days after receipt of the request and the offer of indemnity.

Supplemental Indentures

The Issuer and the Trustee may, without the consent of, or notice to, any of the Bondholders, enter into such indenture or indentures supplemental to the Indenture as shall not be inconsistent with the terms and provisions thereof

(a) to cure any ambiguity, defect or omission in the Indenture, or otherwise amend the Indenture, in such manner as shall not in the opinion of the Trustee impair the security under the Indenture;

(b) to grant to or confer upon the Trustee for the benefit of the Bondholders any additional rights, remedies, powers or authorities that may lawfully be granted to or conferred upon the Bondholders or the Trustee;

(c) to evidence any succession to the Issuer and the assumption by its successor of the covenants, agreements and obligations of the Issuer under the Indenture, the Agreement and the Bonds, to add additional covenants of the Issuer, or to surrender any right or power therein conferred upon the Issuer;

(d) to subject to the pledge of the Indenture additional revenues, properties, or collateral, which may be accomplished by, among other things, entering into instruments with the Company and/or other persons providing for further security, covenants, limitations or restrictions for the benefit of the Bonds;

(e) to modify the Indenture to permit qualification under the Trust Indenture Act of 1939, as amended, or any similar statute at the time in effect;

(f) to amend any provision pertaining to matters under federal income tax laws, including Section 148(f) of the Code;

(g) to authorize different authorized denominations of the Bonds and to make correlative amendments and modifications to the Indenture regarding exchangeability of Bonds of different authorized denominations, redemptions of portions of Bonds of particular authorized denominations and similar amendments and modifications of a technical nature;

(h) to increase or decrease the number of days specified for the giving of notices of mandatory tender and to make corresponding changes to the period for notice of redemption of the Bonds; *provided*, that no decreases in any such number of days will become effective except while the Bonds bear interest at a Daily Rate or a Weekly Rate and until 30 days after the Trustee has given notice to the owners of the Bonds;

(i) to provide for an uncertificated system of registering the Bonds or to provide for the change to or from a Book-Entry System for the Bonds;

(j) to evidence the succession of a new trustee or the appointment by the Trustee or the Issuer of a co-trustee;

(k) to make any change related to the Bonds that does not materially adversely affect the rights of any Bondholder;

(l) prior to, or concurrently with, the conversion of the Bonds to an Auction Rate Period, to make any change appropriate or necessary with respect to the procedures, definitions or provisions in the Indenture or in Exhibit C attached to the Indenture related to the Auction Mode Rate in order to provide for or facilitate the marketability of Bonds in the Auction Mode Rate; and

(m) to make any other changes to the Indenture that take effect as to any or all remarketed Bonds following a mandatory tender.

The Indenture also provides that the owners of not less than a majority in aggregate principal amount of the Bonds outstanding shall have the right, from time to time, to consent to and approve the execution by the Issuer and the Trustee of such other indenture or supplemental indentures as shall be deemed necessary and desirable by the Issuer and the Trustee for the purpose of modifying, altering, amending, adding to or rescinding, in any particular, any of the terms or provisions contained in the Indenture or in any supplemental indenture; *provided, however,* that nothing shall permit, without certain additional consents, (a) an extension of the maturity date of the principal of or the interest on any Bond; (b) a reduction in the principal amount of any Bond, the rate of interest thereon or any redemption premium; or (c) a reduction in the aggregate principal amount of the Bonds required for consent to such supplemental indenture or for actions related to amendments to the Agreement. A Favorable Opinion of Tax Counsel is required for any supplement to the Indenture.

Discharge of the Indenture

If the whole amount of principal and interest due and payable on the Bonds has been paid, or provision shall have been made for payment of the same, and if, at the time of such payment, the Issuer shall have kept, performed and observed all the covenants and promises in such Bonds and in the Indenture required or contemplated to be kept, performed and observed by the Issuer or on its part on or prior to that time, then the Indenture shall be considered to have been discharged in respect of such Bonds and such Bonds shall cease to be entitled to the lien of the Indenture and such lien and all covenants, agreements and other obligations of the Issuer thereunder shall cease, terminate, become void and be completely discharged as to such Bonds.

No Personal Liability of Issuer's Officials

No covenant, stipulation, obligation or agreement of the Issuer contained in the Indenture will be or be deemed to be a covenant, stipulation, obligation or agreement of any present or future member, officer, agent or employee of the Issuer in other than his or her official capacity. No member of the Issuer or official executing the Bonds, the Indenture, the Agreement or any amendment or supplement to the Indenture or the Agreement will be liable personally on the Bonds or be subject to any personal liability or accountability by reason of the issuance or execution thereof.

Removal of Trustee

The Trustee may be removed by the owners of not less than a majority in principal amount of Bonds at the time outstanding or by the Issuer and the Company so long as no Event of Default has occurred and is continuing. The Trustee shall continue to serve as such until a successor Trustee shall be appointed under the Indenture and has accepted such appointment.

REMARKETING

KeyBanc Capital Markets Inc. has been appointed Remarketing Agent for the Bonds. Pursuant to the Remarketing Agreement (the "Remarketing Agreement") to be entered into by the Company and the Remarketing Agent, the Remarketing Agent will agree, subject to certain conditions, to reoffer the Bonds on June 20, 2023 to the public at a purchase price equal to 100% of the principal amount thereof. The Company has agreed to pay the Remarketing Agent $260,000 as a fee, plus expenses. Pursuant to the Remarketing Agreement the Company has agreed to indemnify the Remarketing Agent and its officers, directors and employees, against certain liabilities, including liabilities under the federal securities laws.

After the Bonds are released for sale to the public, the reoffering price and other selling terms may from time to time be varied by the Remarketing Agent and such Bonds may be reoffered and sold to certain dealers (including dealers depositing such Bonds into investment accounts) and others at prices lower than the public reoffering price set forth on the cover hereof.

In connection with this reoffering and in compliance with applicable law and industry practice, the Remarketing Agent may overallot or effect transactions which stabilize, maintain or otherwise affect the market price of the Bonds at levels above those which might otherwise prevail in the open market, including by entering stabilizing bids. A stabilizing bid means the placing of a bid, or the effecting of any purchase, for the purpose of pegging, fixing or maintaining the price of a security. In general, purchases of a security for the purpose of stabilization could cause the price of the security to be higher than it might be in the absence of such purchases.

None of the Issuer, the Company nor the Remarketing Agent make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the Bonds. In addition, none of the Issuer, the Company nor the Remarketing Agent make any representation that the Remarketing Agent will engage in such transactions or that such transactions, once commenced, will not be discontinued without notice.

The Remarketing Agent and its affiliates together comprise a full service financial institution engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. Such activities may involve or relate to assets, securities and/or instruments of the Issuer and/or the Company or its affiliates (whether directly, as collateral securing other obligations or otherwise) and/or persons and entities with relationships with (or that are otherwise involved with transactions by) the Issuer and/or the Company.

The Remarketing Agent and its affiliates may have, from time to time, engaged, and may in the future engage, in transactions with, and performed and may in the future perform, various investment banking services for the Issuer and/or the Company for which they received or will receive customary fees and expenses. Under certain circumstances, the Remarketing Agent and its affiliates may have certain creditor and/or other rights against the Issuer and/or the Company and any affiliates thereof in connection with such transactions and/or services. In addition, the Remarketing Agent and its affiliates may currently have and may in the future have investment and commercial banking, trust and other relationships with parties that may relate to assets of, or be involved in the issuance of securities and/or instruments by, the Issuer and/or the Company and any affiliates thereof. The Remarketing Agent and its affiliates also may communicate independent investment recommendations, market advice or trading ideas and/or publish or express

independent research views in respect of such assets, securities or instruments and at any time may hold, or recommend to clients that they should acquire, long and/or short positions in such assets, securities and instruments.

CONTINUING DISCLOSURE AGREEMENT

The Company will agree to deliver certain continuing disclosure information satisfying the requirements of Rule 15c2-12 ("Rule") under the 1934 Act. The Company will undertake in a written agreement for the benefit of the holders and beneficial owners of the Bonds (the "Continuing Disclosure Undertaking") to provide the Municipal Securities Rulemaking Board ("MSRB") as the sole nationally recognized securities repository through the MSRB's Electronic Municipal Market Access ("EMMA") audited annual financial statements of the Company of the type included in Annex I to Appendix A not later than 120 days after each fiscal year. In addition, the Company will undertake, for the benefit of the holders and beneficial owners of the Bonds, to provide to the MSRB through EMMA, in a timely manner (not in excess of ten (10) business days after the occurrence of such event), notices of any of the events enumerated in the Rule. Notices of the aforesaid events and any filing to be made under the Continuing Disclosure Undertaking may be made solely by transmitting such filing to the MSRB through EMMA as provided at http://emma.msrb.org. The contents of such website do not constitute a part of this Reoffering Circular.

The sole and exclusive remedy for breach or default under the Continuing Disclosure Undertaking is an action to compel specific performance of the undertakings of the Company and no person, including a holder of the Bonds, may recover monetary damages thereunder under any circumstances. A breach or default under the Continuing Disclosure Undertaking shall not constitute an event of default under the Indenture or the Agreement. In addition, if all or any part of the Rule ceases to be in effect for any reason, then, subject to the terms of the Continuing Disclosure Undertaking, the information required to be provided under the Continuing Disclosure Undertaking, insofar as the provision of the Rule no longer in effect required the provision of such information, shall no longer be required to be provided.

TAX EXEMPTION

Original Opinion of Bond Counsel

On June 26, 2014, Bond Counsel delivered its opinion that, under then existing law (i) assuming continuing compliance with certain covenants and the accuracy of certain representations, interest on the Bonds would be excluded from gross income for federal income tax purposes, except interest on any Bond for any period during which it is held by a "substantial user" or a "related person," as those terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"), (ii) interest on the Bonds would be an item of tax preference under Section 57 of the Code for purposes of the federal alternative minimum tax imposed on individuals and corporations (however, it should be noted that under current law, the corporate alternative minimum tax has been repealed, effective for tax years beginning after December 31, 2017), and (iii) the Bonds, and all interest and income thereon, would be exempt from all taxation by the State of West Virginia and any county, municipality, political subdivision or agency thereof, except inheritance taxes. No other opinion was expressed by Bond Counsel regarding the tax consequences of the ownership of or the receipt or accrual of interest on the Bonds. Bond Counsel expressed no opinion with respect to the exemption of interest from income taxation under West

Virginia law on any Bond for any period during which it is held by a person who is a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code.

Bond Counsel's opinion was given in reliance on certifications by representatives of the Issuer and the Company as to certain facts relevant to both the opinion and requirements of the Code, and was subject to the condition that there is compliance subsequent to the issuance of the Bonds with all requirements of the Code that must be satisfied in order for interest thereon to remain excludable from gross income for Federal income tax purposes. The Issuer and the Company have covenanted to comply with provisions of the Code regarding, among other matters, the use, expenditure and investment of the proceeds of the Bonds and the timely payment to the United States of any arbitrage rebate amounts with respect to the Bonds. Failure by the Issuer or the Company to comply with such covenants could cause interest on the Bonds to be included in gross income for Federal income tax purposes retroactively to their date of issue.

Other Tax Matters

In addition to the matters addressed above, prospective purchasers of the Bonds should be aware that the ownership of tax-exempt obligations may result in collateral Federal income tax consequences to certain taxpayers, including without limitation financial institutions, property and casualty insurance companies, S corporations, certain foreign corporations subject to the branch profits tax, recipients of Social Security or Railroad Retirement benefits and taxpayers who may be deemed to have incurred or continued indebtedness to purchase or carry tax-exempt obligations. Prospective purchasers of the Bonds should consult their tax advisors as to the applicability and impact of such consequences.

Each prospective purchaser of the Bonds should consult their own tax advisors as to the status of interest on the Bonds under the tax laws of any commonwealth or state other than West Virginia.

General Considerations

The Internal Revenue Service (the "Service") has a program to audit state and local government obligations to determine whether the interest thereon is includible in gross income for Federal income tax purposes. If the Service does audit the Bonds, under current Service procedures, the Service will treat the Issuer as the taxpayer and the owners of the Bonds will have only limited rights, if any, to participate.

Bond Counsel's opinion represented its legal judgment based in part upon the representations and covenants referenced therein and its review of then current law, but is not a guarantee of result or binding on the Service or the courts. Bond Counsel assumed no duty to update or supplement its opinion to reflect any facts or circumstances that may come to Bond Counsel's attention after the date of its opinion or to reflect any changes in law or the interpretation thereof that may occur or become effective after such date.

There are many events which could affect the value and liquidity or marketability of the Bonds after their issuance, including but not limited to public knowledge of an audit of the Bonds by the Service, a general change in interest rates for comparable securities, a change in Federal or state income tax rates, legislative or regulatory proposals affecting state and local government

securities and changes in judicial interpretation of existing law. In addition, certain tax considerations relevant to owners of Bonds who purchase Bonds after their issuance may be different from those relevant to purchasers upon issuance. Neither the opinion of Bond Counsel nor this Reoffering Circular purport to address the likelihood or effect of any such potential events or such other tax considerations and purchasers of the Bonds should seek advice concerning such matters as they deem prudent in connection with their purchase of Bonds.

Finally, other than the matters specifically referred to above, Bond Counsel expressed no opinion regarding the federal, state, local or other tax consequences of the purchase, ownership and disposition of the Bonds. Prospective purchasers of the Bonds should be aware, however, that the Code contains numerous provisions under which receipt of interest on the Bonds may have adverse federal tax consequences for certain taxpayers. Such consequences include the following: (1) Section 265 of the Code denies a deduction for interest on indebtedness incurred or continued to purchase or carry the Bonds or, in the case of financial institutions, that portion of a holder's interest expense allocated to interest on the Bonds; (2) with respect to insurance companies subject to the tax imposed by Section 831 of the Code, Section 832(b)(5)(B)(i) reduces the deduction for loss reserves by 15% of the sum of certain items, including interest on the Bonds; (3) interest on the Bonds earned by certain foreign corporations doing business in the United States could be subject to a branch profits tax imposed by Section 884 of the Code; (4) passive interest income, including interest on the Bonds, may be subject to federal income taxation under Section 1375 of the Code for Subchapter S corporations that have Subchapter C earnings and profits at the close of the taxable year if greater than 25% of the gross receipts of such Subchapter S corporation is passive investment income; (5) Section 86 of the Code requires recipients of certain Social Security and certain railroad retirement benefits to take into account, in determining the inclusion of such benefits in gross income, receipts or accrual of interest on the Bonds; and (6) under Section 55(b) of the Code, interest on the Bonds may be subject to an alternative minimum tax imposed on "applicable corporations" (within the meaning of Section 59(k) of the Code).

Opinion of Bond Counsel Upon Remarketing

In connection with the proposed change in interest rate Determination Method, Bond Counsel, will render its opinion, that such change will not, by itself, adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, and is permitted under the Act and by the Indenture. In rendering such opinion, Bond Counsel examined such proceedings, documents, matters and law as it deemed necessary to render such opinions. In rendering such opinion, Bond Counsel will assume (and not undertake independently to verify), and therefore will not confirm the continuing correctness of the opinion delivered on June 26, 2014 in connection with the original issuance of the Bonds. Bond Counsel will not obtain, verify or review any information concerning any event, except the matters specifically described in the first sentence of this paragraph, which may have occurred subsequent to the original issuance of the Bonds and which might adversely affect the federal tax treatment of interest on the Bonds. See Appendix B-2 for the proposed form of such opinion.

Prospective purchasers of the Bonds should consult their own tax advisors as to the applicability and extent of federal, state, local or other tax consequences of the purchase, ownership and disposition of the Bonds, including the potential consequences of any pending or proposed legislation, in light of their particular tax situation.

LEGAL MATTERS

Certain legal matters will be passed upon by William E. Johnson, counsel for the Company. William E. Johnson is Senior Counsel of American Electric Power Service Corporation, an affiliate of the Company. Certain legal matters, other than the validity of the Bonds and the exclusion from gross income of interest thereon, will be passed upon by Hunton Andrews Kurth LLP, New York, New York, counsel for the Remarketing Agent. Hunton Andrews Kurth LLP from time to time acts as counsel to the Company and certain affiliates for some matters.

The various legal opinions to be delivered concurrently with the delivery of the Bonds express the professional judgment of the attorneys rendering the opinions as to the legal issues explicitly addressed therein. In rendering a legal opinion, the attorney does not become an insurer or guarantor of the expression of professional judgment, of the transaction opined upon, or of the future performance of the parties to the transaction, nor does the rendering of an opinion guarantee the outcome of any legal dispute that may arise out of the transaction.

MISCELLANEOUS

The attached Appendices are an integral part of this Reoffering Circular and must be read together with all of the balance of this Reoffering Circular.

The Issuer does not assume any responsibility for the matters contained in this Reoffering Circular other than information under *THE ISSUER*. All findings and determinations by the Issuer relating to the issuance and sale of the Bonds are, and have been, made by the Issuer for its own internal uses and purposes in performing its duties under West Virginia law.

APPENDIX A

KENTUCKY POWER COMPANY

Kentucky Power Company (the "Company") is engaged in the generation, transmission and distribution of electric power to approximately 163,000 retail customers in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. The Company owns 1,075 MW of generating capacity. The Company uses its generation to serve its retail and other customers. As of December 31, 2023, the Company had 285 employees. The principal industries served by the Company include petroleum and coal products manufacturing, chemical manufacturing, coal-mining, oil and gas extraction and pipeline transportation. The Company's principal executive offices are located at 1 Riverside Plaza, Columbus, Ohio, and the telephone number is (614) 716-1000.

FINANCIAL STATEMENTS

Annex 1 to this Appendix A contains the balance sheets of the Company as of December 31, 2022 and 2021 and the statements of income, comprehensive income (loss), changes in common shareholder's equity and cash flows for each of the two years in the period ended December 31, 2022 and the related notes thereto. Annex 2 to this Appendix A contains the unaudited condensed balance sheets of the Company as of March 31, 2023 and December 31, 2022 and the unaudited condensed statements of income, comprehensive income (loss), changes in common shareholder's equity and statements of cash flows of the Company for the three months in the periods ended March 31, 2023 and 2022 and the related notes thereto.

RISK FACTORS

An investment in the Bonds involves a number of risks. Risks described below should be carefully considered together with the other information included in this Reoffering Circular. Any of the events or circumstances described as risks below could result in a significant or material adverse effect on our business, results of operations, cash flows or financial condition, and a corresponding decline in the market price of, or our ability to repay, the Bonds. The risks and uncertainties described below may not be the only risks and uncertainties that we face. Additional risks and uncertainties not currently known or that we currently deem immaterial may also result in a significant or material adverse effect on our business, results of operations, cash flow or financial condition. References to "we", "our" or similar terms mean Kentucky Power Company.

Risks Related To Our Business

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions.

Our business plan calls for extensive investment in capital improvements and additions including the construction of additional transmission facilities, modernizing existing infrastructure as well as other initiatives. We currently provide service at rates approved by the Kentucky Public Service Commission ("KPSC") and the Federal Energy Regulatory Commission ("FERC"). If these regulatory commissions do not approve adjustments to the rates we charge, we would not be

able to recover the costs associated with our planned extensive investment. This would cause our financial results to be diminished.

Our regulated electric revenues, earnings and results are dependent on regulation that may limit our ability to recover costs and other amounts.

The rates we collect for providing electricity are subject to approval by the KPSC and FERC. If these regulators do not allow recovery of costs incurred in providing service on a timely basis, it could reduce future net income and cash flows and impact financial condition. Similarly, if recovery or other rate relief authorized in the past is overturned or reversed on appeal, our future earnings could be negatively impacted. Any regulatory action or litigation outcome that triggers a reversal of a regulatory asset or deferred cost generally results in an impairment to the balance sheet and a charge to the income statement. For additional information, see Note 4 – Rate Matters of the notes to the financial statements, included in the 2022 Annual Report appearing elsewhere in this reoffering circular.

Our transmission investment strategy and execution are dependent on federal and state regulatory policy.

A significant portion of our earnings is derived from transmission investments and activities. FERC policy currently favors the expansion and updating of the transmission infrastructure within its jurisdiction. If the FERC were to adopt a different policy, if states were to limit or restrict such policies, or if transmission needs do not continue or develop as projected, our strategy of investing in transmission could be impacted. Management believes our experience with transmission facilities construction and operation gives us an advantage over other competitors in securing authorization to install, construct and operate new transmission lines and facilities. However, there can be no assurance that PJM or other regional transmission organizations ("RTOs") will authorize new transmission projects or will award such projects to us.

Certain elements of our transmission formula rates have been challenged, which could result in lowered rates and/or refunds of amounts previously collected and thus have an adverse effect on our business, financial condition, results of operations and cash flows.

We provide transmission service under rates regulated by the FERC. The FERC has approved the cost-based formula rate templates used by us to calculate its respective annual revenue requirements, but it has not expressly approved the amount of actual capital and operating expenditures to be used in the formula rates. All aspects of our rates accepted or approved by the FERC, including the formula rate templates, the rates of return on the actual equity portion of its respective capital structures and the approved targeted capital structures, are subject to challenge by interested parties at the FERC, or by the FERC on its own initiative. In addition, interested parties may challenge the annual implementation and calculation by us of its projected rates and formula rate true-up pursuant to its approved formula rate templates under our formula rate implementation protocols. If a challenger can establish that any of these aspects are unjust, unreasonable, unduly discriminatory or preferential, then the FERC can make appropriate

prospective adjustments to them and/or disallow any of our inclusion of those aspects in the rate setting formula.

Inquiries related to rates of return, as well as challenges to the formula rates of other utilities, are ongoing in other proceedings at the FERC. The results of these proceedings could potentially negatively impact us in any future challenges to our formula rates. If the FERC orders revenue reductions, including refunds, in any future cases related to its formula rates, it could reduce future net income and cash flows and impact financial condition.

End-use consumers and entities supplying electricity to end-use consumers may also attempt to influence government and/or regulators to change the rate setting methodologies that apply to us, particularly if rates for delivered electricity increase substantially.

We face risks to project siting, financing, construction, permitting, governmental approvals and the negotiation of project development agreements that may impede their development and operating activities.

We own, develop, construct, manage and operate electric generation, transmission and distribution facilities. A key component of our growth is its ability to construct and operate these facilities. As part of these operations, we must periodically apply for licenses and permits from various local, state, federal and other regulatory authorities and abide by their respective conditions. Should we be unsuccessful in obtaining necessary licenses or permits on acceptable terms or resolving third-party challenges to such licenses or permits, should there be a delay in obtaining or renewing necessary licenses or permits or should regulatory authorities initiate any associated investigations or enforcement actions or impose related penalties or disallowances, it could reduce future net income and cash flows and impact financial condition. Any failure to negotiate successful project development agreements for new facilities with third-parties could have similar results.

Changes in technology and regulatory policies may lower the value of electric utility facilities and franchises.

We primarily generate electricity and deliver that electricity to customers over transmission and distribution facilities to customers situated within an exclusive franchise. This method results in economies of scale and generally lower costs than newer technologies such as fuel cells and microturbines, and distributed generation using either new or existing technology. Other technologies, such as light emitting diodes (LEDs), increase the efficiency of electricity and, as a result, lower the demand for it. Changes in regulatory policies and advances in batteries or energy storage, wind turbines and photovoltaic solar cells are reducing costs of new technology to levels that are making them competitive with some central station electricity production and delivery. These developments can challenge our competitive ability to maintain relatively low cost, efficient and reliable operations, to establish fair regulatory mechanisms and to provide cost-effective programs and services to customers. Further, in the event that alternative generation resources are mandated, subsidized or encouraged through legislation or regulation or otherwise are economically competitive and added to the available generation supply, such resources could

displace a higher marginal cost generating units, which could reduce the price at which market participants sell their electricity.

We may not recover costs incurred to begin construction on projects that are canceled.

Our business plan for the construction of new projects involves a number of risks, including construction delays, nonperformance by equipment and other third-party suppliers, and increases in equipment and labor costs. To limit the risks of these construction projects, we enter into equipment purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals and/or siting or environmental permits. If any of these projects is canceled for any reason, including our failure to receive necessary regulatory approvals and/or siting or environmental permits, we could incur significant cancellation penalties under the equipment purchase orders and construction contracts. In addition, if we have recorded any construction work or investments as an asset we may need to impair that asset in the event the project is canceled.

We are exposed to risks through participation in the market and transmission structures in various regional power markets that are beyond their control.

Results are likely to be affected by differences in the market and transmission structures in various regional power markets. The rules governing the various RTOs, such as PJM, may also change from time to time which could affect costs or revenues. Existing, new or changed rules of these RTOs could result in significant additional fees and increased costs to participate in those structures, including the cost of transmission facilities built by others due to changes in transmission rate design. In addition, these RTOs may assess costs resulting from improved transmission reliability, reduced transmission congestion and firm transmission rights. As members of PJM, we are subject to certain additional risks, including the allocation among existing members, of losses caused by unreimbursed defaults of other participants in these markets and resolution of complaint cases that may seek refunds of revenues previously earned by members of these markets.

Our financial performance may be adversely affected if we are unable to successfully operate our facilities or perform certain corporate functions.

Our performance is highly dependent on the successful operation of our transmission and distribution facilities. Operating these facilities involves many risks, including:

- Operator error and breakdown or failure of equipment or processes.
- Operating limitations that may be imposed by regulatory requirements.
- Labor disputes.
- Compliance with mandatory reliability standards, including mandatory cyber security standards.
- Information technology failure that impairs our information technology infrastructure or disrupts normal business operations.

- Information technology failure that affects our ability to access customer information or causes us to lose confidential or proprietary data that materially and adversely affects our reputation or exposes us to legal claims.
- Supply chain disruptions and inflation.
- Fuel or water supply interruptions caused by transportation constraints, adverse weather such as drought, non-performance by suppliers and other factors.
- Catastrophic events such as fires, earthquakes, explosions, hurricanes, tornados, ice storms, terrorism (including cyber-terrorism), floods or other similar occurrences.
- Fuel costs and related requirements triggered by financial stress in the coal industry.

Physical attacks or hostile cyber intrusions could severely impair operations, lead to the disclosure of confidential information and damage our reputation.

We face physical security and cybersecurity risks as the owner-operators of generation, transmission and/or distribution facilities and as participants in commodities trading. We own assets deemed as critical infrastructure, the operation of which is dependent on information technology systems. Further, the computer systems that run these facilities are not completely isolated from external networks. Parties that wish to disrupt the U.S. bulk power system or our operations could view these computer systems, software or networks as targets for cyber-attack. In addition, the electric utility business requires the collection of sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss.

A security breach of our physical assets or information systems, interconnected entities in RTOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system. We could be subject to financial harm associated with ransomware theft or inappropriate release of certain types of information, including sensitive customer, vendor, employee, trading or other confidential data. A successful cyber-attack on the systems that control generation, transmission, distribution or other assets could severely disrupt business operations, preventing service to customers or collection of revenues. The breach of certain business systems could affect the ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. We and our third-party vendors have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to their technology systems and confidential data or to attempts to disrupt utility and related business operations. While there have been immaterial incidents of phishing, unauthorized access to technology systems, financial fraud, and disruption of remote access across our system, there has been no material impact on business or operations from these attacks. However, we cannot guarantee that security efforts will detect or prevent breaches, operational incidents, or other breakdowns of technology systems and network infrastructure and cannot provide any assurance that such incidents will not have a material adverse effect in the future.

The amount of taxes imposed on us could change.

We are subject to income taxation at the federal level and by certain states and municipalities. In determining our income tax liability for these jurisdictions, management monitors changes to the applicable tax laws and related regulations. While management believes it is in compliance with current prevailing laws, one or more taxing jurisdictions could seek to impose incremental or new taxes on the company. In addition, any adverse developments in these laws or regulations, including legislative changes, judicial holdings or administrative interpretations, could have a material and adverse effect on financial condition and results of operations.

If we are unable to access capital markets or insurance markets on reasonable terms, it could reduce our future net income and cash flows and negatively impact our financial condition.

We rely on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows, and on insurance markets to assist in managing our risk and liability profile. Volatility, increased interest rates and reduced liquidity in the financial markets could affect our ability to raise capital on reasonable terms to fund capital needs, including construction costs and refinancing maturing indebtedness. Certain sources of insurance and debt and equity capital have expressed increasing unwillingness to procure insurance for or to invest in companies, such as us, that rely on fossil fuels. The public holds diverse and often conflicting views on the use of fossil fuels. We have multiple stakeholders, including our customers, associates, federal and state regulatory authorities, and the communities in which we operate, and these stakeholders will often have differing priorities and expectations regarding issues related to the use of fossil fuels. Any adverse publicity in connection with our use of fossil fuels could curtail availability from certain sources of capital. If our sources of capital are reduced, capital costs could increase materially. Restricted access to capital or insurance markets and/or increased borrowing costs or insurance premiums could reduce future net income and cash flows and negatively impact financial condition.

Our operating results may fluctuate on a seasonal or quarterly basis and with general economic and weather conditions.

Electric power consumption is generally seasonal. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, overall operating results in the future may fluctuate substantially on a seasonal basis. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could reduce future net income and cash flows and negatively impact financial condition. In addition, unusually extreme weather conditions could impact our results of operations in a manner that would not likely be sustainable.

Our revenues and results of operations are subject to risks that are beyond our control.

The cost of repairing damage to our facilities due to storms, natural disasters, wars, terrorist acts and other catastrophic events, in excess of reserves established for such repairs, may harm our revenues, operating and capital expenses and results of operations.

Supply chain disruptions and inflation could negatively impact our operations and corporate strategy.

Our operations and business plans depend on the global supply chain to procure the equipment, materials and other resources necessary to build and provide services in a safe and reliable manner. The delivery of components, materials, equipment and other resources that are critical to our business operations and corporate strategy has been restricted by domestic and global supply chain upheaval. This has resulted in the shortage of critical items. International tensions, including the ramifications of regional conflict, could further exacerbate the global supply chain upheaval. These disruptions and shortages could adversely impact business operations and corporate strategy. The constraints in the supply chain could restrict the availability and delay the construction, maintenance or repair of items that are needed to support normal operations or are required to execute on our corporate strategy for continued capital investment in utility equipment. These disruptions and constraints could reduce future net income and cash flows and possibly harm our financial condition.

Supply chain disruptions have contributed to higher prices of components, materials, equipment and other needed commodities and these inflationary increases may continue in the future. The economy in the United States has encountered a material level of inflation compared to the recent past and that has contributed to increased uncertainty in the outlook of near-term economic activity, including the level of future inflation and the possibility of a recession. We typically recover increases in capital expenses from customers through rates. Failure to recover increased capital costs could reduce future net income and cash flows and possibly harm our financial condition. Increases in inflation raises our costs for labor, materials and services, and failure to secure these on reasonable terms may adversely impact our financial condition.

Our results of operations and cash flows may be negatively affected by a lack of growth or slower growth in the number of customers or decline in customer demand.

Growth in customer accounts and growth of customer usage each directly influence demand for electricity and the need for additional power generation and delivery facilities. Customer growth and customer usage are affected by a number of factors outside of our control, such as mandated energy efficiency measures, demand-side management goals, distributed generation resources and economic and demographic conditions, such as population changes, job and income growth, housing starts, new business formation and the overall level of economic activity, including changes due to public health considerations.

Failure to attract and retain an appropriately qualified workforce could harm our results of operations.

Certain events, such as an aging workforce without appropriate replacements, mismatch of skillset or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include potential higher rates of existing employee departures, lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect the ability to manage and operate the business. If we are unable to successfully attract and retain an appropriately qualified workforce, future net income and cash flows may be reduced.

Parties we have engaged to provide construction materials or services may fail to perform their obligations, which could harm our results of operations.

Our business plan calls for extensive investment in capital improvements and additions, including the construction of additional transmission facilities as well as other initiatives. We are exposed to the risk of substantial price increases in the costs of materials used in construction. We have engaged numerous contractors and entered into a large number of agreements to acquire the necessary materials and/or obtain the required construction related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and almost certainly cause delays in that and related projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. This would cause our financial results to be diminished, and we might incur losses or delays in completing construction.

Changes in the price of commodities, emission allowances for criteria pollutants and the costs of transport may increase our cost of producing power, impacting financial performance.

We are exposed to changes in the price and availability of fuel (including the cost to procure coal and gas) and the price and availability to transport fuel. We have existing contracts of varying durations for the supply of fuel, but as these contracts end or if they are not honored, we may not be able to purchase fuel on terms as favorable as the current contracts. The inability to procure fuel at costs that are economical could cause us to retire generating capacity prior to the end of its useful life, and while we typically recover expenditures for undepreciated plant balances, there can be no assurance in the future that we will recover such costs. Similarly, we are exposed to changes in the price and availability of emission allowances. We use emission allowances based on the amount of fuel used and reductions achieved through emission controls and other measures. Based on current environmental programs remaining in effect, we have sufficient emission allowances to cover the majority of the projected needs for the next two years and beyond. Additional costs may be incurred either to acquire additional allowances or to achieve further reductions in emissions.

If we need to obtain allowances, those purchases may not be on as favorable terms as those under the current environmental programs. Our risks relative to the price and availability to transport coal include the volatility of the price of diesel which is the primary fuel used in transporting coal by barge.

Prices for coal, natural gas and emission allowances have shown material swings in the past. Changes in the cost of fuel, emission allowances or natural gas and changes in the relationship between such costs and the market prices of power could reduce future net income and cash flows and negatively impact financial condition.

In addition, actual power prices and fuel costs will differ from those assumed in financial projections used to value trading and marketing transactions, and those differences may be material. As a result, as those transactions are marked-to-market, they may impact future results of operations and cash flows and impact financial condition.

We are subject to physical and financial risks associated with climate change.

Climate change creates physical and financial risk. Physical risks from climate change include an increase in sea level and changes in weather conditions, such as changes in precipitation and extreme weather events. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes.

Increased energy use due to weather changes may require us to invest in additional transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions.

Severe weather impacts our service territories, primarily when thunderstorms, tornadoes, hurricanes and snow or ice storms occur. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations. A negative impact to water supplies due to long-term drought conditions could adversely impact our ability to provide electricity to customers, as well as increase the price they pay for energy. We may not recover all costs related to mitigating these physical and financial risks.

To the extent climate change impacts a region's economic health, it may also impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods and services, has an impact on the economic health of our communities.

Hazards associated with high-voltage electricity transmission may result in suspension of our operations or the imposition of civil or criminal penalties.

Our operations are subject to the usual hazards associated with high-voltage electricity transmission, including explosions, fires, inclement weather, natural disasters, mechanical failure, unscheduled downtime, equipment interruptions, remediation, chemical spills, discharges or releases of toxic or hazardous substances or gases and other environmental risks. The hazards can cause personal injury and loss of life, severe damage to or destruction of property and equipment and environmental damage, and may result in suspension of operations and the imposition of civil or criminal penalties. We maintain property and casualty insurance, but we are not fully insured against all potential hazards incident to our business, such as damage to poles, towers and lines or losses caused by outages.

Costs of compliance with existing and evolving environmental laws are significant.

Operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. A majority of the electricity we generated is produced by the combustion of fossil fuels. Emissions of nitrogen and sulfur oxides, mercury and particulates and the discharge and disposal of solid waste (including coal-combustion residuals or CCR) resulting from fossil fueled generation plants are subject to increased regulations, controls and mitigation expenses. Compliance with these legal requirements (including any new and more stringent application of existing CCR regulations) requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees, disposal, remediation and permits at our facilities and could cause us to retire generating capacity prior to the end of its estimated useful life. Costs of compliance with environmental statutes and regulations could reduce future net income and negatively impact financial condition, especially if emission limits, CCR waste discharge and/or discharge disposal obligations are tightened, more extensive operating and/or permitting requirements are imposed or additional substances or facilities become regulated. Although we typically recover expenditures for pollution control technologies, replacement generation, undepreciated plant balances and associated operating costs from customers, there can be no assurance in the future that we will recover the remaining costs associated with such plants. Failure to recover these costs could reduce future net income and cash flows and possibly harm financial condition.

Regulation of greenhouse gas emissions could materially increase our costs or cause our electric generating unit to be uneconomical to operate or maintain.

Federal or state laws or regulations may be adopted that would impose new or additional limits on the emissions of greenhouse gases, including, but not limited to, carbon dioxide and methane, from electric generation units using fossil fuels like coal. The potential effects of greenhouse gas emission limits on our electric generation units are subject to significant uncertainties based on, among other things, the timing of the implementation of any new requirements, the required levels of emission reductions, the nature of any market-based or tax-based mechanisms adopted to facilitate reductions, the relative availability of greenhouse gas emission reduction offsets, the development of cost-effective, commercial-scale carbon capture

and storage technology and supporting regulations and liability mitigation measures, and the range of available compliance alternatives.

Our results of operations could be materially adversely affected to the extent that new federal or state laws or regulations impose any new greenhouse gas emission limits. Any future limits on greenhouse gas emissions could create substantial additional costs in the form of taxes or emissions allowances, require significant capital investment in carbon capture and storage technology, fuel switching, or the replacement of high-emitting generation facilities with lower-emitting generation facilities and/or could cause us to retire generating capacity prior to the end of its estimated useful life. Although we typically recover environmental expenditures, there can be no assurance in the future that we can recover such costs which could reduce future net income and cash flows and possibly harm financial condition.

Courts adjudicating nuisance and other similar claims in the future may order us to pay damages or to limit or reduce emissions.

In the past, there have been several cases seeking damages based on allegations of federal and state common law nuisance in which our affiliates, among others, were defendants. In general, the actions allege that emissions from the defendants' power plants constitute a public nuisance. The plaintiffs in these actions generally seek recovery of damages and other relief. If future actions are resolved against us, substantial modifications of our existing coal-fired power plant could be required and we might be required to limit or reduce emissions. Such remedies could require us to purchase power from third parties to fulfill our commitments to supply power to our customers. This could have a material impact on costs. In addition, we could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay damages or penalties and/or halt operations. While management believes such costs should be recoverable from customers as costs of doing business, without such recovery, those costs could reduce future net income and cash flows and harm financial condition. Moreover, results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

Commodity trading and marketing activities are subject to inherent risks which can be reduced and controlled but not eliminated.

We routinely have open trading positions in the market, within guidelines, resulting from the management of our trading portfolio. To the extent open trading positions exist, fluctuating commodity prices can improve or diminish financial results and financial position.

Our power trading activities also expose us to risks of commodity price movements. To the extent that our power trading does not hedge the price risk associated with the generation we own, or control, we would be exposed to the risk of rising and falling spot market prices.

In connection with these trading activities, we routinely enter into financial contracts, including futures and options, over-the counter options, financially-settled swaps and other derivative contracts. These activities expose us to risks from price movements. If the values of

the financial contracts change in a manner we do not anticipate, it could harm financial position or reduce the financial contribution of trading operations.

We rely on electric transmission facilities that we do not own or control. If these facilities do not provide us with adequate transmission capacity, we may not be able to deliver wholesale electric power to the purchasers of our power.

We depend on transmission facilities owned and operated by other nonaffiliated power companies to deliver the power we sell at wholesale. This dependence exposes us to a variety of risks. If transmission is disrupted, or transmission capacity is inadequate, we may not be able to sell and deliver wholesale power. If a region's power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

The FERC has issued electric transmission initiatives that require electric transmission services to be offered unbundled from commodity sales. Although these initiatives are designed to encourage wholesale market transactions, access to transmission systems may not be available if transmission capacity is insufficient because of physical constraints or because it is contractually unavailable. We also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

We are subject to various regulatory requirements, including reliability standards; contract filing requirements; reporting, recordkeeping and accounting requirements; and transaction approval requirements.

Under federal law, owners and operators of the bulk power transmission system are subject to mandatory reliability standards, including both operational and cybersecurity standards, promulgated by the North American Electric Reliability Corporation ("NERC") and enforced by the FERC. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with new reliability standards may subject us to higher operating costs and/or increased capital expenditures. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties, which likely would not be recoverable.

The Company must comply with FERC requirements for approval of certain transactions; reporting, recordkeeping and accounting requirements; and for filing contracts related to the provision of jurisdictional services. Under FERC policy, failure to file jurisdictional agreements on a timely basis may result in foregoing the time value of revenues collected under the agreement, but not to the point where a loss would be incurred. The failure to obtain timely approval of transactions or to comply with applicable reporting, recordkeeping or accounting requirements could subject us to penalties that could have a material adverse effect on our financial condition, results of operations and cash flows.

Acts of war, terrorist attacks, natural disasters, severe weather and other catastrophic events may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Acts of war, terrorist attacks, natural disasters, severe weather and other catastrophic events may negatively affect our business, financial condition and cash flows in unpredictable ways, such as increased security measures and disruptions of markets. Energy related assets, including, for example, our transmission facilities and the generation and distribution facilities that we interconnect with, may be at risk of acts of war, terrorist attacks, as well as natural disasters, severe weather and other catastrophic events. Such events or the threat of such events may increase costs associated with heightened security requirements. In addition, such events or threats may have a material effect on the economy in general and could result in a decline in energy consumption, which may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Downgrades in our credit ratings could negatively affect our ability to access capital.

The credit ratings agencies periodically review our capital structure and the quality and stability of our earnings. Any negative ratings actions could constrain the capital available to us and could limit our access to funding for our operations. Our business is capital intensive, and we are dependent upon our ability to access capital at rates and on terms we determine to be attractive. In periods of market turmoil, access to capital is difficult for all borrowers. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and could reduce future net income and cash flows and impact financial condition.

New climate disclosure rules proposed by the U.S. Securities and Exchange Commission may increase our costs of compliance and adversely impact our business.

On March 21, 2022, the SEC proposed new rules relating to the disclosure of a range of climate-related risks. We currently assessing the proposed rule, but at this time we cannot predict the costs of implementation or any potential adverse impacts resulting from the rule. To the extent this rule is finalized as proposed, we could incur increased costs relating to the assessment and disclosure of climate-related risks. We may also face increased litigation risks related to disclosures made pursuant to the rule if finalized as proposed. In addition, enhanced climate disclosure requirements could accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon-intensive sectors.

Risks Relating to Our Corporate and Financial Structure

The Trustee's rights under the Agreement are unsecured and effectively subordinated to any future secured debt of the Company, to the extent of the value of the collateral therefor.

The Trustee's rights under the Agreement are unsecured obligations and therefor will be effectively subordinated to our future secured indebtedness. As of December 31, 2022, we had no

secured indebtedness outstanding. If we were to incur secured indebtedness and if we defaulted under the Agreement or certain other indebtedness or became bankrupt, liquidated or reorganized, any secured creditor could use the value of the collateral securing that debt to satisfy their secured indebtedness before the Trustee would receive any payment for the benefit of the Bonds. If the value of such collateral is not sufficient to pay any secured indebtedness in full, our secured creditors would share the value of our other assets, if any, with the Trustee and the holders of other claims against us which rank equally to the Agreement.

We could enter into various transactions that could increase the amount of its outstanding indebtedness, or adversely affect its capital structure or credit ratings, or otherwise adversely affect the holders of the Bonds.

The terms of the Agreement do not prevent us from entering into a variety of acquisition, refinancing, recapitalization or other highly-leveraged transactions. As a result, we may enter into a transaction even though the transaction could increase the total amount of its outstanding indebtedness, adversely affect its capital structure or credit ratings or otherwise adversely affect the holders of the Bonds.

As of March 31, 2023, the Company had approximately $1.3 billion of indebtedness outstanding.

Certain provisions in our debt instruments limit our financial and operating flexibility.

Our outstanding debt instruments contain numerous financial and operating covenants that place significant restrictions on, among other things, our ability to:

- create liens;
- dispose of certain assets;
- enter into certain lines of business;
- engage in transactions with affiliates;
- engage in mergers and consolidations

Our outstanding debt instruments also require us to meet certain financial ratios, such as maintaining certain debt to capitalization ratios. Our ability to comply with these and other requirements and restrictions may be affected by changes in economic or business conditions, results of operations or other events beyond our control. A failure to comply with the obligations contained in any of our debt instruments could result in acceleration of certain of our outstanding debt and the acceleration of debt under other instruments evidencing indebtedness that may contain cross-acceleration provisions.

INDEPENDENT AUDITORS

The financial statements of Kentucky Power Company as of December 31, 2022 and 2021 and for the years then ended, included in this Reoffering Circular, have been audited by PricewaterhouseCoopers LLP, independent auditors, as stated in their report appearing herein.

ANNEX 1

Kentucky Power Company

2022 Annual Report

Audited Financial Statements

KENTUCKY POWER℠
An AEP Company
BOUNDLESS ENERGY℠

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GLOSSARY OF TERMS

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 consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated VIE of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KGPCo, KPCo, OPCo and WPCo.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AFUDC	Allowance for Equity Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ASU	Accounting Standards Update.
CCR	Coal Combustion Residual.
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.
ELG	Effluent Limitation Guidelines.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE of AEP.
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.

Term	Meaning
OPEB	Other Postretirement Benefits.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third-party sales. AEPSC acts as the agent.
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, jointly-owned by AEGCo and I&M, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
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.
SPP	Southwest Power Pool regional transmission organization.
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.
VIE	Variable Interest Entity.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	West Virginia Public Service Commission.

Report of Independent Auditors

To the Management and Board of Directors of Kentucky Power Company

Opinion

We have audited the accompanying financial statements of Kentucky Power Company (the "Company"), which comprise the balance sheets as of December 31, 2022 and 2021, and the related statements of income, of comprehensive income (loss), of changes in common shareholder's equity and of cash flows for the years then ended, including the related notes (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date the financial statements are available to be issued.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

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In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

PricewaterhouseCoopers LLP

Columbus, Ohio
February 23, 2023

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2022 and 2021
(in thousands)

	Years Ended December 31, 2022	2021
REVENUES		
Electric Generation, Transmission and Distribution	$ 752,371	$ 634,765
Sales to AEP Affiliates	19,251	10,542
Other Revenues	1,599	1,076
TOTAL REVENUES	773,221	646,383
EXPENSES		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	277,291	167,027
Purchased Electricity from AEP Affiliates	93,137	93,365
Other Operation	133,992	126,479
Maintenance	64,821	64,353
Depreciation and Amortization	123,238	115,097
Taxes Other Than Income Taxes	26,919	27,745
TOTAL EXPENSES	719,398	594,066
OPERATING INCOME	53,823	52,317
Other Income (Expense):		
Interest Income	134	19
Allowance for Equity Funds Used During Construction	1,192	1,822
Non-Service Cost Components of Net Periodic Benefit Cost	6,490	4,141
Interest Expense	(45,115)	(35,628)
INCOME BEFORE INCOME TAX BENEFIT	16,524	22,671
Income Tax Benefit	(31,028)	(27,479)
NET INCOME	$ 47,552	$ 50,150

The common stock of KPCo is wholly-owned by Parent.

See Notes to Financial Statements beginning on page 11.

KENTUCKY POWER COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2022 and 2021
(in thousands)

	Years Ended December 31, 2022	2021
Net Income	$ 47,552	$ 50,150
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(21) and $(36) in 2022 and 2021, Respectively	(79)	(137)
Pension and OPEB Funded Status, Net of Tax of $0 and $268 in 2022 and 2021, Respectively	—	1,008
Pension and OPEB Adjustment Related to Plant Transfers, Net of Tax of $(444) and $0 in 2022 and 2021, Respectively	(1,670)	—
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(1,749)	871
TOTAL COMPREHENSIVE INCOME	$ 45,803	$ 51,021

See Notes to Financial Statements beginning on page 11.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2022 and 2021
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2020	$ 50,450	$ 526,135	$ 245,871	$ 878	$ 823,334
Net Income			50,150		50,150
Other Comprehensive Income				871	871
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2021	50,450	526,135	296,021	1,749	874,355
Capital Contribution from Parent		152			152
Net Income			47,552		47,552
Other Comprehensive Loss				(1,749)	(1,749)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	$ 50,450	$ 526,287	$ 343,573	$ —	$ 920,310

See Notes to Financial Statements beginning on page 11.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2022 and 2021
(in thousands)

	December 31, 2022	December 31, 2021
CURRENT ASSETS		
Cash and Cash Equivalents	$ 2,684	$ 763
Accounts Receivable:		
Customers	63,432	16,281
Affiliated Companies	10,818	25,578
Accrued Unbilled Revenues	35,002	16,647
Miscellaneous	72	57
Allowance for Uncollectible Accounts	(1,013)	(3)
Total Accounts Receivable	108,311	58,560
Fuel	21,994	10,090
Materials and Supplies	26,182	20,515
Risk Management Assets	8,463	5,986
Regulatory Asset for Under-Recovered Fuel Costs	23,241	8,216
Margin Deposits	960	14,229
Prepayments and Other Current Assets	2,512	3,490
TOTAL CURRENT ASSETS	194,347	121,849
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,236,474	1,231,494
Transmission	801,838	760,359
Distribution	1,061,601	1,017,406
Other Property, Plant and Equipment	167,981	137,554
Construction Work in Progress	137,964	95,093
Total Property, Plant and Equipment	3,405,858	3,241,906
Accumulated Depreciation and Amortization	1,156,221	1,104,492
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	2,249,637	2,137,414
OTHER NONCURRENT ASSETS		
Regulatory Assets	504,185	476,457
Employee Benefit and Pension Assets	20,531	60,333
Operating Lease Assets	528	10,748
Deferred Charges and Other Noncurrent Assets	37,877	33,848
TOTAL OTHER NONCURRENT ASSETS	563,121	581,386
TOTAL ASSETS	$ 3,007,105	$ 2,840,649

See Notes to Financial Statements beginning on page 11.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2022 and 2021
(dollars in thousands)

	December 31, 2022	December 31, 2021
CURRENT LIABILITIES		
Advances from Affiliates	$ 94,428	$ 47,895
Accounts Payable:		
General	56,969	52,837
Affiliated Companies	51,076	42,223
Long-term Debt Due Within One Year – Nonaffiliated	490,000	200,000
Risk Management Liabilities	—	51
Customer Deposits	38,784	32,432
Accrued Taxes	40,272	45,243
Accrued Interest	8,543	5,685
Obligations Under Operating Leases	128	2,173
Other Current Liabilities	17,284	21,384
TOTAL CURRENT LIABILITIES	797,484	449,923
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	688,448	903,105
Deferred Income Taxes	456,217	437,152
Regulatory Liabilities	108,853	140,506
Asset Retirement Obligations	18,447	16,399
Employee Benefits and Pension Obligations	9,736	8,064
Obligations Under Operating Leases	450	8,614
Deferred Credits and Other Noncurrent Liabilities	7,160	2,531
TOTAL NONCURRENT LIABILITIES	1,289,311	1,516,371
TOTAL LIABILITIES	2,086,795	1,966,294
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	526,287	526,135
Retained Earnings	343,573	296,021
Accumulated Other Comprehensive Income (Loss)	—	1,749
TOTAL COMMON SHAREHOLDER'S EQUITY	920,310	874,355
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 3,007,105	$ 2,840,649

See Notes to Financial Statements beginning on page 11.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2022 and 2021
(in thousands)

	Years Ended December 31, 2022	2021
OPERATING ACTIVITIES		
Net Income	$ 47,552	$ 50,150
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	123,238	115,097
Deferred Income Taxes	(31,793)	(24,509)
Allowance for Equity Funds Used During Construction	(1,192)	(1,822)
Mark-to-Market of Risk Management Contracts	(2,542)	(2,992)
Pension and Postemployment Benefit Reserves	31,242	(1,343)
Deferred Fuel Over/Under-Recovery, Net	(15,025)	(8,529)
Change in Regulatory Assets	(28,263)	(56,447)
Asset Retirement Obligation	—	(2,174)
Change in Other Noncurrent Assets	(5,950)	(10,503)
Change in Other Noncurrent Liabilities	5,339	2,979
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(49,138)	(7,482)
Fuel, Materials and Supplies	(17,492)	11,771
Margin Deposits	13,269	(14,097)
Accounts Payable	22,773	13,013
Accrued Taxes, Net	(4,843)	8,628
Other Current Assets	777	384
Other Current Liabilities	(3,198)	(3,522)
Net Cash Flows from Operating Activities	84,754	68,602
INVESTING ACTIVITIES		
Construction Expenditures	(210,346)	(164,912)
Proceeds from Sales of Assets	8,004	1,075
Other Investing Activities	685	2,995
Net Cash Flows Used for Investing Activities	(201,657)	(160,842)
FINANCING ACTIVITIES		
Capital Contribution from Parent	152	—
Issuance of Long-term Debt - Nonaffiliated	149,869	149,974
Change in Advances from Affiliates, Net	46,533	(17,752)
Retirement of Long-term Debt - Nonaffiliated	(75,000)	(40,000)
Principal Payments for Finance Lease Obligations	(2,735)	(920)
Other Financing Activities	5	168
Net Cash Flows from Financing Activities	118,824	91,470
Net Increase (Decrease) in Cash and Cash Equivalents	1,921	(770)
Cash and Cash Equivalents at Beginning of Period	763	1,533
Cash and Cash Equivalents at End of Period	$ 2,684	$ 763
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 41,512	$ 37,378
Net Cash Paid (Received) for Income Taxes	2,489	(4,123)
Noncash Acquisitions Under Finance Leases	131	331
Construction Expenditures Included in Current Liabilities as of December 31,	18,898	28,280

See Notes to Financial Statements beginning on page 11.

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1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 163,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

In December 2022, the UPA between AEGCo, an affiliated company, and KPCo ended upon the termination of the Rockport Plant, Unit 2 lease. The UPA allowed KPCo to purchase 30% of AEGCo's 50% capacity of Rockport Plant, Unit 2. Following the end of the lease, KPCo reached an agreement with I&M, an affiliated company, to purchase capacity from Rockport Plant, Unit 2 through May 2024 at a rate equal to PJM's RPM clearing price.

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

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

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

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

In addition, the FERC regulates the 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.

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 in conformity with GAAP 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 include temporary cash investments with original maturities of three months or less.

AEP System Tax Allocation

KPCo joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. Historically, the allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocated the benefit of current tax loss of the parent company (Parent Company Loss Benefit) to the AEP System subsidiaries through a reduction of current tax expense. In the first quarter of 2022, AEP and subsidiaries changed accounting for the Parent Company Loss Benefit from a reduction of current tax expense to an allocation through equity. The impact of this change was immaterial to KPCo's financial statements. The consolidated net operating losses of the AEP System is allocated to each company in the consolidated group with taxable loss. With the exception of the allocation of the consolidated AEP System net operating losses, the loss of the Parent and tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

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 Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

Allowance for Uncollectible Accounts

Prior to the first quarter of 2022, KPCo sold, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit under an affiliated receivables sales arrangement. Under the arrangement, KPCo was charged a fee for each sale based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience from previous purchases of KPCo's customer accounts receivable. As a result, no allowance for uncollectible accounts was 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 recorded an allowance for uncollectible accounts on its balance sheet for those receivables no longer sold to AEP Credit. KPCo's bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable.

Concentrations of Credit Risk and Significant Customers

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

Significant Customer of KPCo: Marathon Petroleum Company	2022	2021
Percentage of Total Revenues	14 %	12 %
Percentage of Accounts Receivable – Customers	14 %	45 %

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. Removal costs accrued are typically recorded as regulatory liabilities when the revenue received for removal costs accrued exceeds actual removal costs incurred. The asset removal costs liability is relieved as removal costs are incurred. A regulatory asset balance will occur if actual removal costs incurred exceed accumulated removal costs accrued.

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

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

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

Allowance for Funds Used During Construction

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. KPCo records the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Asset Retirement Obligations (ARO)

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

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances from Affiliates, 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 Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is an expectation that refunds or recoveries will extend beyond a one year period, based on a company's filing with a commission or a commission directive. These deferrals are amortized when refunded or when billed to customers in later months with the KPSC's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the KPSC. On a routine basis, the KPSC reviews and/or audits KPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. Changes in fuel costs, including purchased power, are reflected in rates in a timely manner through the FAC. A portion of margins from off-system sales are given to customers through the FAC.

Revenue Recognition

Regulatory Accounting

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

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

Electricity Supply and Delivery Activities

KPCo recognizes revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes such revenues on the statements of income as the performance obligations of delivering energy to customers are satisfied. Recognized revenues include unbilled as well as-billed amounts. Wholesale transmission revenue is based on a FERC-approved formula rate filing made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under-recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. The annual true-up meets the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations". An estimated annual true-up is recorded by KPCo in the fourth quarter of each calendar year and a final annual true-up is recognized by KPCo in the second quarter of each calendar year following the filing of the annual FERC report. Any portion of the true-up applicable to an affiliated company is recorded as Accounts Receivable - Affiliated Companies or Accounts Payable - Affiliated 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 16 - Revenue from Contracts with Customers for additional information.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

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

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale 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 Purchased Electricity for Resale 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 Risk Management Assets or Liabilities, as appropriate, and on KPCo's statements of income in Total 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

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

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

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

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. The net amortization expense is included in Interest Expense on the statements of income.

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	30 %
Fixed Income	54 %
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, 2022 and 2021, the fair value of securities on loan as part of the program was $83 million and $137 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2022 and 2021.

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-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).

Earnings Per Share (EPS)

KPCo is a wholly-owned subsidiary of AEP. Therefore, KPCo is not required to report EPS.

Supplementary Income Statement Information

The following table provides the components of Depreciation and Amortization for the years ended December 31, 2022 and 2021:

Depreciation and Amortization	Years Ended December 31, 2022	2021
	(in thousands)	
Depreciation and Amortization of Property, Plant and Equipment	$ 108,301	$ 102,390
Amortization of Regulatory Assets and Liabilities	14,937	12,707
Total Depreciation and Amortization	$ 123,238	$ 115,097

Disposition of KPCo and KTCo

In October 2021, AEP entered into a Stock Purchase Agreement (SPA) to sell KPCo and KTCo to Liberty Utilities Co., a subsidiary of Algonquin Power & Utilities Corp. (Liberty), for approximately a $2.85 billion enterprise value. In May 2022, the KPSC approved the transfer of KPCo to Liberty subject to certain conditions contingent upon the closing of the sale. AEP has received clearance under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR) and the Committee on Foreign Investment in the United States during 2022. Clearance under the HSR expired in January 2023. AEP and Liberty refiled a joint application seeking HSR clearance in February 2023. The sale is also contingent upon FERC approval under Section 203 of the Federal Power Act. The parties to the SPA have certain termination rights if the closing of the sale does not occur by April 26, 2023.

Transfer of Ownership

FERC Proceedings

In December 2021, Liberty, KPCo and KTCo (the applicants) requested FERC approval of the sale under Section 203 of the Federal Power Act. In February 2022, several intervenors in the case filed protests related to whether the sale will negatively impact the wholesale transmission rates of applicants. In April 2022, the FERC issued a deficiency letter stating that the Section 203 application is deficient and that additional information is required to process it. In May 2022, Liberty, KPCo and KTCo supplemented the application. In December 2022, the FERC issued an order denying, without prejudice, authorization of the proposed sale stating the applicants failed to demonstrate the proposed transaction will not have an adverse effect on rates.

In January 2023, AEP, AEPTCo, and Liberty entered into an amendment to the SPA that specified the applicants will submit a new filing for approval under Section 203 of the Federal Power Act. The new filing was submitted to the FERC on February 14, 2023. The applicants requested expedited treatment of the new filing, including an

accelerated comment period. In response, the FERC granted a shortened 45 day comment period. The applicants believe the new Section 203 application addresses the concerns raised in the FERC's December 2022 order. The application contains several additional commitments by Liberty to mitigate potential adverse impacts on FERC jurisdictional rates over the next five years, including: a) maintaining the current return on equity; b) maintaining the current cost cap on equity; c) financing future investments at the current credit rating; and d) capping certain operating and administrative costs. The sale remains subject to FERC approval. The statute requires an order from the FERC within 180 days of the February 14, 2023 filing date in accordance with Section 203 of the Federal Power Act.

KPSC Proceedings

In May 2022, the KPSC approved the transfer of KPCo to Liberty subject to conditions contingent upon the closing of the sale, including establishment of regulatory liabilities to subsidize retail customer transmission and distribution expenses, a fuel adjustment clause bill credit, and a three-year Big Sandy decommissioning rider rate holiday during which KPCo's carrying charge is reduced by 50%.

Mitchell Plant Operations and Maintenance Agreement and Ownership Agreement

KPCo and WPCo each own a 50% undivided interest in the 1,560 MW coal-fired Mitchell Plant. As of December 31, 2022 and 2021, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $577 million and $586 million, respectively. The SPA includes a condition precedent to closing requiring the issuance of regulatory orders approving new Mitchell Plant agreements.

The KPSC and WVPSC issued orders proposing materially different modifications to the Mitchell Plant agreements filed by AEP such that the new agreements could not be executed by the parties. In lieu of new agreements, in July 2022, KPCo and WPCo confirmed with the KPSC and WVPSC, respectively, that they will continue operating under the existing Mitchell Agreement, utilizing the Mitchell Agreement Operating Committee's authority under that agreement to issue appropriate resolutions so the parties can operate in accordance with each state commission's directives related to CCR and ELG investment. In September 2022, pursuant to resolutions under the existing Mitchell Plant agreement, WPCo replaced KPCo as the Operator of Mitchell Plant.

Summary

Management believes it is probable that FERC authorization under Section 203 of the Federal Power Act will be received and closing will occur after receipt of the order 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.

In June 2022, KPCo entered into agreements to purchase assets under lease, terminating remaining lease obligations prior to the original maturity date. As a result of the early terminations, current obligations under operating and finance leases of $1.9 million and $583 thousand, respectively, and noncurrent obligations under operating and finance leases of $7.2 million and $1.4 million, respectively, were relieved from KPCo's balance sheet in the second quarter of 2022.

Subsequent Events

Management reviewed subsequent events through February 23, 2023, the date that KPCo's 2022 annual report was available to be issued.

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, 2022 and 2021. 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.

For the Year Ended December 31, 2022	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB Changes in Funded Status	Total
		(in thousands)	
Balance in AOCI as of December 31, 2021	$ 2,890	$ (1,141)	$ 1,749
Change in Fair Value Recognized in AOCI, Net of Tax	—	—	—
Amount of (Gain) Loss Reclassified from AOCI			
Amortization of Prior Service Cost (Credit)	(119)	—	(119)
Amortization of Actuarial (Gains) Losses	19	—	19
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(100)	—	(100)
Income Tax (Expense) Benefit	(21)	—	(21)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(79)	—	(79)
Pension and OPEB Adjustment Related to Plant Transfers	—	(2,114)	(2,114)
Income Tax (Expense) Benefit	—	(444)	(444)
Pension and OPEB Adjustment Related to Plant Transfers, Net of Income Tax (Expense) Benefit	—	(1,670)	(1,670)
Net Current Period Other Comprehensive Income (Loss)	(79)	(1,670)	(1,749)
Balance in AOCI as of December 31, 2022	$ 2,811	$ (2,811)	$ —

For the Year Ended December 31, 2021	Pension and OPEB Amortization of Deferred Costs	Pension and OPEB 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, Net of Tax	—	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)
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

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.

CCR/ELG Compliance Plan Filings

KPCo and WPCo each own a 50% interest in the Mitchell Plant. As of December 31, 2022, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $577 million. 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 May 2022, the KPSC approved recovery of the Kentucky jurisdictional share of ELG costs incurred at the Mitchell Plant prior to July 15, 2021.

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 also ordered that WPCo will be given the opportunity to recover, from its customers, the ELG and 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. The WVPSC's order further states that unless KPCo pays for its share of costs for ELG improvements and costs necessary to continue operations beyond 2028, the benefit of the capacity and energy made possible by those improvements and operating Mitchell Plant beyond 2028 should benefit only West Virginia jurisdictional customers who have shared in paying for those costs.

Storm-Related Costs

In June 2022, KPCo's service territory was impacted by strong winds from severe storms resulting in system damages and power outages. In July 2022, KPCo's service territory was impacted again by severe storms, which caused flash flooding, resulting in additional system damages and power outages. In August 2022, KPCo filed an application with the KPSC requesting deferral authority for $18 million of incremental operation and maintenance costs related to these storms. In September 2022, the KPSC issued an order granting deferral authority. KPCo intends to seek recovery of the deferral in a future base rate case. If any of these incremental storm costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Deferred Purchased Power Expenses

In September 2022, the KPSC initiated a proceeding to investigate the appropriate amortization period and recovery mechanism for the deferral of Kentucky Deferred Purchased Power Expenses related to the Rockport Plant Unit Power Agreement, as well as KPCo's ability to use the level of non-fuel, non-environmental Rockport UPA expense included in base rates to earn its authorized ROE in 2023 since the KPCo UPA ended in December 2022. KPCo requested the KPSC approve the terms related to each of the foregoing items as reflected in the settlement agreement in the 2017 Kentucky Base Rate Case, including recovery of the Kentucky Deferred Purchased Power Expenses over five years through a rider beginning in December 2022. In December 2022, the KPSC approved

KPCo's request and recovery began through a rider, including recovery of an estimated allowed cost (Rockport Offset) of $22.8 million in accordance with the terms of the settlement agreement in the 2017 Kentucky Base Rate Case permitting KPCo to use the level of non-fuel, non-environmental Rockport UPA expense included in base rates to earn its authorized ROE in 2023. This estimated Rockport Offset is subject to true-up based on KPCo's actual 2023 financial results and KPSC review in the first quarter of 2024. The actual Rockport Offset cannot exceed $40.8 million. If the actual Rockport Offset is not recoverable, it could 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:

Regulatory Assets:	December 31, 2022	December 31, 2021	Remaining Recovery Period
	(in thousands)		
Current Regulatory Assets			
Under-recovered Fuel Costs - does not earn a return	$ 23,241	$ 8,216	1 year
Total Current Regulatory Assets	23,241	8,216	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Kentucky Deferred Purchased Power Expenses	$ —	$ 47,528	
Total Regulatory Assets Currently Earning a Return	—	47,528	
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs (a)	74,430	56,506	
Other Regulatory Assets Pending Final Regulatory Approval	1,699	893	
Total Regulatory Assets Currently Not Earning a Return	76,129	57,399	
Total Regulatory Assets Pending Final Regulatory Approval	76,129	104,927	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs	178,502	193,229	18 years
Plant Retirement Costs - Asset Retirement Obligation Costs	110,010	109,577	18 years
Kentucky Deferred Purchased Power Expenses	52,970	—	5 years
Plant Retirement Costs - Materials and Supplies	3,016	3,016	18 years
Other Regulatory Assets Approved for Recovery	931	928	various
Total Regulatory Assets Currently Earning a Return	345,429	306,750	
Regulatory Assets Currently Not Earning a Return			
Fuel and Purchased Power Rider	38,164	28,727	2 years
Pension and OPEB Funded Status	23,704	12,236	12 years
Plant Retirement Costs - Asset Retirement Obligation Costs	5,295	4,721	18 years
Environmental Costs	5,139	5,920	2 years
Postemployment Benefits	4,416	3,410	3 years
Storm Related Costs	100	2,167	1 year
Other Regulatory Assets Approved for Recovery	5,809	7,599	various
Total Regulatory Assets Currently Not Earning a Return	82,627	64,780	
Total Regulatory Assets Approved for Recovery	428,056	371,530	
Total Noncurrent Regulatory Assets	$ 504,185	$ 476,457	

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

Regulatory Liabilities:	December 31, 2022	December 31, 2021	Remaining Refund Period
	(in thousands)		
Noncurrent Regulatory Liabilities			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a) (b)	$ (32,843)	$ —	
Total Regulatory Liabilities Currently Paying a Return	(32,843)	—	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	2,098	2,098	
Total Regulatory Liabilities Currently Not Paying a Return	2,098	2,098	
Total Regulatory Liabilities Pending Final Regulatory Determination	(30,745)	2,098	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	74,393	57,793	(c)
Income Taxes, Net (a)	54,732	73,213	(d)
Total Regulatory Liabilities Currently Paying a Return	129,125	131,006	
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Gain on Forward Commitments	3,982	3,199	2 years
Off-system Sales Margin Sharing	3,417	—	1 year
PJM Transmission Enhancement Refund	2,031	2,644	3 years
Other Regulatory Liabilities Approved for Payment	1,043	1,559	various
Total Regulatory Liabilities Currently Not Paying a Return	10,473	7,402	
Total Regulatory Liabilities Approved for Payment	139,598	138,408	
Total Noncurrent Regulatory Liabilities	$ 108,853	$ 140,506	

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

(b) Represents an income tax related regulatory asset, which is presented within net regulatory liabilities on the balance sheet.

(c) Relieved as removal costs are incurred.

(d) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $40.7 million and $81.4 million for the years ended December 31, 2022 and 2021, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2022 is to be refunded over 6 years.

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, 2022:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 5,993	$ 12,002	$ 11,985	$ 20,474	$ 50,454
Energy and Capacity Purchase Contracts	—	1,577	—	—	1,577
Total	$ 5,993	$ 13,579	$ 11,985	$ 20,474	$ 52,031

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

GUARANTEES

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

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2022, 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.

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, 2022, 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, 2022, 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. On August 16, 2022, the district court granted the motion to dismiss the complaint without prejudice. The plaintiffs filed a motion for leave to file an amended complaint, which the Court denied on December 1, 2022. The plaintiffs did not file an appeal by the deadline of January 3, 2023.

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	2022	2021	2022	2021
Discount Rate	5.50 %	2.90 %	5.50 %	2.90 %
Interest Crediting Rate	4.25 %	4.00 %	NA	NA
Rate of Compensation Increase	5.10 % (a)	4.90 % (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 2022, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with an average increase of 5.1%.

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	**2022**	**2021**	**2022**	**2021**
Discount Rate	2.90 %	2.50 %	2.90 %	2.55 %
Interest Crediting Rate	4.00 %	4.00 %	NA	NA
Expected Return on Plan Assets	5.25 %	4.75 %	5.50 %	4.75 %
Rate of Compensation Increase	4.90 % (a)	4.90 % (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	**2022**	**2021**
Initial	7.50 %	6.25 %
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, 2022, 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, 2022, the pension plans had an actuarial gain primarily due to an increase in the discount rate and was partially offset by increases in the assumed lump sum conversion rate and cash balance account interest crediting rate. For the year ended December 31, 2022, the OPEB plans had an actuarial gain primarily due to an increase in the discount rate and updated per capita cost assumptions. The OPEB plans gains were partially offset by a projected reduction in the Employer Group Waiver Program catastrophic reinsurance offset provided to AEP, resulting from the Inflation Reduction Act as well as an increase in the health care cost trend assumption. 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. The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		OPEB	
	2022	2021	2022	2021
Change in Benefit Obligation		(in thousands)		
Benefit Obligation as of January 1,	$ 184,199	$ 198,433	$ 36,932	$ 45,058
Service Cost	2,739	3,477	172	283
Interest Cost	4,480	4,840	953	1,096
Actuarial Gain	(36,034)	(9,831)	(3,106)	(5,851)
Plan Amendments	—	—	—	(216)
Transfers	(57,450)	—	(7,548)	—
Benefit Payments	(11,079)	(12,720)	(5,520)	(5,156)
Participant Contributions	—	—	1,713	1,708
Medicare Subsidy	—	—	9	10
Benefit Obligation as of December 31,	$ 86,855	$ 184,199	$ 23,605	$ 36,932
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 203,932	$ 208,552	$ 77,433	$ 75,920
Actual Gain (Loss) on Plan Assets	(31,289)	8,095	(13,714)	4,960
Transfers	(78,502)	—	—	—
Company Contributions	—	5	(15,776)	1
Participant Contributions	—	—	1,713	1,708
Benefit Payments	(11,079)	(12,720)	(5,520)	(5,156)
Fair Value of Plan Assets as of December 31,	$ 83,062	$ 203,932	$ 44,136	$ 77,433
Funded (Underfunded) Status as of December 31,	$ (3,793)	$ 19,733	$ 20,531	$ 40,501

Amounts Recognized on the Balance Sheets

	Pension Plans		OPEB	
	December 31,			
	2022	2021	2022	2021
	(in thousands)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ —	$ 19,832	$ 20,531	$ 40,501
Other Current Liabilities – Accrued Short-term Benefit Liability	(4)	(3)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(3,789)	(96)	—	—
Funded (Underfunded) Status	$ (3,793)	$ 19,733	$ 20,531	$ 40,501

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

The following tables show the components of the plans included in Regulatory Assets and the items attributable to the change in these components:

	Pension Plans		OPEB	
	December 31,			
	2022	2021	2022	2021
Components	(in thousands)			
Net Actuarial (Gain) Loss	$ 16,985	$ 22,630	$ 9,355	$ (6,622)
Prior Service Credit	—	—	(2,637)	(5,987)
Recorded as				
Regulatory Assets	$ 16,986	$ 21,923	$ 6,718	$ (9,687)
Deferred Income Taxes	(1)	148	—	(614)
Net of Tax AOCI	—	559	—	(2,308)

	Pension Plans		OPEB	
	2022	2021	2022	2021
Components	(in thousands)			
Actuarial (Gain) Loss During the Year	$ 3,370	$ (9,345)	$ 14,492	$ (7,332)
Amortization of Actuarial Loss	(1,867)	(3,523)	—	—
Prior Service Credit	—	—	—	(216)
Amortization of Prior Service Credit	—	—	2,375	2,499
Transfers - Prior Service Cost	—	—	975	—
Transfers - (Gain)/loss	(7,148)	—	1,485	—
Change for the Year Ended December 31,	$ (5,645)	$ (12,868)	$ 19,327	$ (5,049)

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,			
2022	2021	2022	2021
2.0 %	3.8 %	2.8 %	3.8 %

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2022:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 347.6	$ —	$ —	$ —	$ 347.6	8.4 %
International	398.4	—	—	—	398.4	9.7 %
Common Collective Trusts (b)	—	—	—	379.9	379.9	9.2 %
Subtotal – Equities	746.0	—	—	379.9	1,125.9	27.3 %
Fixed Income (a):						
United States Government and Agency Securities	(0.6)	1,071.4	—	—	1,070.8	26.0 %
Corporate Debt	—	891.7	—	—	891.7	21.6 %
Foreign Debt	—	140.2	—	—	140.2	3.4 %
State and Local Government	—	37.0	—	—	37.0	0.9 %
Other – Asset Backed	—	0.8	—	—	0.8	— %
Subtotal – Fixed Income	(0.6)	2,141.1	—	—	2,140.5	51.9 %
Infrastructure (b)	—	—	—	109.2	109.2	2.6 %
Real Estate (b)	—	—	—	276.9	276.9	6.7 %
Alternative Investments (b)	—	—	—	319.7	319.7	7.8 %
Cash and Cash Equivalents (b)	—	64.9	—	58.3	123.2	3.0 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	29.3	29.3	0.7 %
Total	$ 745.4	$ 2,206.0	$ —	$ 1,173.3	$ 4,124.7	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2022:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 414.1	$ —	$ —	$ —	$ 414.1	26.7 %
International	265.0	—	—	—	265.0	17.1 %
Common Collective Trusts (a)	—	—	—	169.1	169.1	10.9 %
Subtotal – Equities	679.1	—	—	169.1	848.2	54.7 %
Fixed Income:						
Common Collective Trust Debt (a)	—	—	—	120.3	120.3	7.8 %
United States Government and Agency Securities	0.1	155.8	—	—	155.9	10.1 %
Corporate Debt	—	141.5	—	—	141.5	9.1 %
Foreign Debt	—	21.0	—	—	21.0	1.4 %
State and Local Government	62.9	7.8	—	—	70.7	4.6 %
Subtotal – Fixed Income	63.0	326.1	—	120.3	509.4	33.0 %
Trust Owned Life Insurance:						
International Equities	—	46.7	—	—	46.7	3.0 %
United States Bonds	—	110.3	—	—	110.3	7.1 %
Subtotal – Trust Owned Life Insurance	—	157.0	—	—	157.0	10.1 %
Cash and Cash Equivalents (a)	23.2	—	—	6.7	29.9	1.9 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	4.8	4.8	0.3 %
Total	$ 765.3	$ 483.1	$ —	$ 300.9	$ 1,549.3	100.0 %

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

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 (b)	—	—	—	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 (b)	—	—	—	92.1	92.1	1.7 %
Real Estate (b)	—	—	—	232.6	232.6	4.4 %
Alternative Investments (b)	—	—	—	448.8	448.8	8.4 %
Cash and Cash Equivalents (b)	—	64.3	—	53.4	117.7	2.2 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	(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 represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 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 (a)	—	—	—	265.0	265.0	13.0 %
Subtotal – Equities	770.3	—	—	265.0	1,035.3	50.7 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	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 (a)	33.0	—	—	6.7	39.7	1.9 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	6.0	6.0	0.3 %
Total	$ 895.2	$ 703.7	$ —	$ 445.4	$ 2,044.3	100.0 %

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

Accumulated Benefit Obligation

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

	December 31, 2022	December 31, 2021
	(in thousands)	
Qualified Pension Plan	$ 84,724	$ 177,132
Nonqualified Pension Plan	49	34
Total Accumulated Benefit Obligation	$ 84,773	$ 177,166

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,	
	2022	2021
	(in thousands)	
Projected Benefit Obligation	$ 86,855	$ 98
Fair Value of Plan Assets	83,062	—
Underfunded Projected Benefit Obligation	$ (3,793)	$ (98)

Accumulated Benefit Obligation

	Underfunded Pension Plans	
	December 31,	
	2022	2021
	(in thousands)	
Accumulated Benefit Obligation	$ 84,773	$ 34
Fair Value of Plan Assets	83,062	—
Underfunded Accumulated Benefit Obligation	$ (1,711)	$ (34)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the Pension and OPEB plans of $4 thousand and $53 thousand, respectively, during 2023. 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)	
2023	$ 7,342	$ 3,690
2024	7,781	3,534
2025	7,766	3,708
2026	7,554	3,692
2027	7,874	3,586
Years 2028 to 2032, in Total	36,110	16,525

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,			
	2022	2021	2022	2021
	(in thousands)			
Service Cost	$ 2,739	$ 3,477	$ 172	$ 283
Interest Cost	4,480	4,840	953	1,096
Expected Return on Plan Assets	(8,116)	(8,583)	(3,885)	(3,479)
Amortization of Prior Service Credit	—	—	(2,375)	(2,499)
Amortization of Net Actuarial Loss	1,867	3,523	—	—
Net Periodic Benefit Cost (Credit)	970	3,257	(5,135)	(4,599)
Capitalized Portion	(1,287)	(1,582)	(81)	(129)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ (317)	$ 1,675	$ (5,216)	$ (4,728)

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 $2.0 million in 2022 and $2.3 million in 2021.

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, 2022	December 31, 2021	Unit of Measure
	(in thousands)		
Commodity:			
Power	3,450	6,927	MWhs
Heating Oil and Gasoline	—	305	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. The amount of cash collateral from third-parties netted against short-term and long-term risk management assets and the amount of cash collateral paid to third-parties netted against short-term and long-term risk management liabilities were immaterial for KPCo as of December 31, 2022 and 2021.

The following tables represent the gross fair value of KPCo's derivative activity on the balance sheets. Unless shown as a separate line on the balance sheets due to materiality, Current Risk Management Assets are included in Prepayments and Other Current Assets, Long-term Risk Management Assets are included in Deferred Charges and Other Noncurrent Assets, Current Risk Management Liabilities are included in Other Current Liabilities and Long-term Risk Management Liabilities are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

	December 31, 2022		
Balance Sheet Location	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)	
Current Risk Management Assets	$ 8,607	$ (144)	$ 8,463
Long-term Risk Management Assets	137	(137)	—
Total Assets	8,744	(281)	8,463
Current Risk Management Liabilities	144	(144)	—
Long-term Risk Management Liabilities	137	(137)	—
Total Liabilities	281	(281)	—
Total MTM Derivative Contract Net Assets	$ 8,463	$ —	$ 8,463

	December 31, 2021		
Balance Sheet Location	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)	
Current Risk Management Assets	$ 7,488	$ (1,502)	$ 5,986
Long-term Risk Management Assets	46	(46)	—
Total Assets	7,534	(1,548)	5,986
Current Risk Management Liabilities	1,458	(1,407)	51
Long-term Risk Management Liabilities	46	(46)	—
Total Liabilities	1,504	(1,453)	51
Total MTM Derivative Contract Net Assets (Liabilities)	$ 6,030	$ (95)	$ 5,935

(a) Derivative instruments within this category are disclosed as gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.

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

Amount of Gain (Loss) Recognized on Risk Management Contracts

	Years Ended December 31,	
Location of Gain (Loss)	2022	2021
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 8	$ (12)
Purchased Electricity for Resale	228	118
Other Operation	148	90
Maintenance	263	116
Regulatory Assets (a)	(25)	(1,077)
Regulatory Liabilities (a)	16,998	11,192
Total Gain on Risk Management Contracts	$ 17,620	$ 10,427

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

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 (Loss) 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 Total Revenues or Purchased Electricity for Resale on KPCo's statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2022 and 2021, 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 (Loss) on its balance sheets into Interest Expense on its statements of income in those periods in which hedged interest payments occur. During the years ended 2022 and 2021, 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 (Loss) on KPCo's balance sheets as of December 31, 2022 and 2021.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes. As of December 31, 2022, 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, 2022 and 2021, KPCo did not have derivative contracts with collateral triggering events in a net liability position.

Cross-Acceleration Triggers

Certain interest rate derivative contracts contain cross-acceleration provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-acceleration provisions could be triggered if there was a non-performance event by KPCo under any of their outstanding debt of at least $50 million and the lender on that debt has accelerated the entire repayment obligation. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-acceleration provisions in contracts. KPCo had no derivative contracts with cross-acceleration provisions in a net liability position as of December 31, 2022 and 2021, respectively. There was no cash collateral posted as of December 31, 2022 and 2021. If a cross-acceleration provision would have been triggered, settlement at fair value would have been required. KPCo had no derivative contracts with cross-acceleration provisions outstanding as of December 31, 2022 and 2021.

Cross-Default Triggers

In addition, a majority of KPCo's non-exchange-traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third-party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. KPCo's derivative contracts with cross-default provisions outstanding as of December 31, 2022 and 2021 were not material. There was no cash collateral posted as of December 31, 2022 and 2021, respectively. If a cross-default provision would have been triggered, settlement at fair value would have been required.

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,			
	2022		2021	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 1,178,448	$ 1,148,769	$ 1,103,105	$ 1,224,664

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, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 137	$ 8,607	$ (281)	$ 8,463
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 137	$ 144	$ (281)	$ —

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2021

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

(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, 2022	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2021	$ 5,871
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	2,801
Settlements	(8,672)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	8,463
Balance as of December 31, 2022	$ 8,463

Year Ended December 31, 2021	Net Risk Management 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

(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, 2022 and 2021:

Significant Unobservable Inputs
December 31, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in thousands)						
FTRs	$ 8,607	$ 144	Discounted Cash Flow	Forward Market Price	$ (3.10)	$ 18.79	$ 2.48

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					

(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, 2022 and 2021:

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, 2022	2021
	(in thousands)	
Federal:		
Current	$ 74	$ (2,970)
Deferred	(30,347)	(20,143)
Total Federal	(30,273)	(23,113)
State and Local:		
Current	691	—
Deferred	(1,446)	(4,366)
Total State and Local	(755)	(4,366)
Income Tax Benefit	$ (31,028)	$ (27,479)

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, 2022	2021
	(in thousands)	
Net Income	$ 47,552	$ 50,150
Income Tax Benefit	(31,028)	(27,479)
Pretax Income	$ 16,524	$ 22,671
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 3,470	$ 4,761
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Reversal of Origination Flow-Through	1,475	1,891
State and Local Income Taxes, Net	(594)	(3,449)
Removal Costs	(2,660)	(2,154)
Tax Adjustments (a)	—	3,098
Tax Reform Excess ADIT Reversal (b)	(32,452)	(31,174)
Other	(267)	(452)
Income Tax Benefit	$ (31,028)	$ (27,479)
Effective Income Tax Rate	(187.8)%	(121.2)%

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

(b) In January 2021, as part of the 2020 Kentucky Base Rate Case, the KPSC issued an order that shortened the previously authorized refund period for Excess ADIT that is not subject to normalization requirements from 18 years to 3 years.

Net Deferred Tax Liability

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

	December 31, 2022	December 31, 2021
	(in thousands)	
Deferred Tax Assets	$ 86,163	$ 94,062
Deferred Tax Liabilities	(542,380)	(531,214)
Net Deferred Tax Liabilities	$ (456,217)	$ (437,152)
Property Related Temporary Differences	$ (304,463)	$ (310,721)
Amounts Due to Customers for Future Income Taxes	39,613	51,754
Deferred State Income Taxes	(96,837)	(92,617)
Regulatory Assets	(109,919)	(101,155)
Net Operating Loss Carryforward	11,671	17,475
All Other, Net	3,718	(1,888)
Net Deferred Tax Liabilities	$ (456,217)	$ (437,152)

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. AEP has agreed to extend the statute of limitations on the 2017 and 2018 tax returns to December 31, 2023, to allow time for the current IRS audit to be completed including a refund claim approval by the Congressional Joint Committee on Taxation. The statute of limitations for the 2019 return is set to naturally expire in 2023 as well.

The current IRS audit and associated refund claim evolved from a net operating loss carryback to 2015 that originated in the 2017 return. AEP has received and agreed to two IRS proposed adjustments on the 2017 tax return, which were immaterial. The exam is nearly complete and AEP is currently working with the IRS to submit the refund claim to the Congressional Joint Committee on Taxation for resolution and final approval.

Net Income Tax Operating Loss Carryforward

KPCo has state net income tax operating loss carryforwards of $222 million in 2022. As a result, KPCo recognized deferred state income tax benefits in 2022 of $11 million. This is consistent with the net operating loss carryforwards and deferred state income tax benefits recognized in 2021. Management anticipates future taxable income will be sufficient to realize the state net income tax operating loss tax benefits before the state carryforward begins expiring in 2035.

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 lease rentals and finance lease amortization costs are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Interest on finance lease liabilities is generally charged to Interest Expense. Lease costs associated with capital projects are included in Property, Plant and Equipment 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, 2022	2021
	(in thousands)	
Operating Lease Cost	$ 14,058	$ 3,100
Finance Lease Cost:		
Amortization of Finance Leases	2,735	920
Interest on Finance Leases	63	125
Total Lease Rental Costs (a)	$ 16,856	$ 4,145

(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): December 31, 2022	2021	Weighted-Average Discount Rate December 31, 2022	2021
Operating Leases	5.92	6.05	2.95 %	3.33 %
Finance Leases	4.73	4.68	4.41 %	4.00 %

	Years Ended December 31,	
	2022	2021
	(in thousands)	
Cash Paid for Amounts Included in the Measurement of Lease Liabilities		
Operating Cash Flows Used for Operating Leases	$ 14,050	$ 3,089
Operating Cash Flows Used for Finance Leases	63	125
Financing Cash Flows Used for Finance Leases	2,735	920
Non-cash Acquisitions Under Operating Leases	$ 422	$ 1,261

The following tables show the property, plant and equipment under finance leases and noncurrent assets under operating leases and related obligations recorded on KPCo's balance sheets. Unless shown as a separate line on the balance sheets due to materiality, net operating lease assets are included in Deferred Charges and Other Noncurrent Assets, current finance lease obligations are included in Other Current Liabilities and long-term finance lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets. Lease obligations are not recognized on the balance sheets for lease agreements with a lease term of less than twelve months.

	December 31,	
	2022	2021
	(in thousands)	
Property, Plant and Equipment Under Finance Leases		
Generation	$ 465	$ 1,106
Other Property, Plant and Equipment	209	4,348
Total Property, Plant and Equipment Under Finance Leases	674	5,454
Accumulated Amortization	305	2,599
Net Property, Plant and Equipment Under Finance Leases	$ 369	$ 2,855
Obligations Under Finance Leases		
Noncurrent Liability	$ 288	$ 2,064
Liability Due Within One Year	81	791
Total Obligations Under Finance Leases	$ 369	$ 2,855

	December 31,	
	2022	2021
	(in thousands)	
Operating Lease Assets	$ 528	$ 10,748
Obligations Under Operating Leases		
Noncurrent Liability	$ 450	$ 8,614
Liability Due Within One Year	128	2,173
Total Obligations Under Operating Leases	$ 578	$ 10,787

Future minimum lease payments consisted of the following as of December 31, 2022:

Future Minimum Lease Payments	Finance Leases	Operating Leases
	(in thousands)	
2023	$ 95	$ 154
2024	88	136
2025	85	81
2026	71	64
2027	54	46
After 2027	18	198
Total Future Minimum Lease Payments	411	679
Less: Imputed Interest	42	101
Estimated Present Value of Future Minimum Lease Payments	$ 369	$ 578

Lessor Activity

KPCo's lessor activity was immaterial as of and for the twelve months ended December 31, 2022 and December 31, 2021, 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, 2022	Interest Rate Ranges as of December 31, 2022	Interest Rate Ranges as of December 31, 2021	Outstanding as of December 31, 2022	Outstanding as of December 31, 2021
					(in thousands)	
Senior Unsecured Notes	2024-2047	4.54%	3.13%-8.13%	3.13%-8.13%	$ 688,626	$ 688,400
Pollution Control Bonds	2023 (a)	2.35%	2.35%	2.35%	64,896	64,823
Other Long-term Debt	2022-2023	5.26%	5.03%-5.55%	0.76%-1.61%	424,926	349,882
Total Long-term Debt Outstanding					$ 1,178,448	$ 1,103,105

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

As of December 31, 2022, outstanding long-term debt was payable as follows:

	2023	2024	2025	2026	2027	After 2027	Total
				(in thousands)			
Principal Amount	$ 490,000	$ 65,000	$ —	$ 200,000	$ 40,000	$ 385,000	$1,180,000
Debt Issuance Costs							(1,552)
Total Long-term Debt Outstanding							$1,178,448

Dividend Restrictions

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

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

KPCo has credit agreements that contain a covenant that limit its debt to capitalization ratio to 67.5%. As of December 31, 2022, 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, 2022, 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 $613.2 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, 2022, the amount of any such restrictions was $36.5 million.

Corporate Borrowing Program – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2022 and 2021 are included in Advances from Affiliates 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)			
2022	$ 161,643	$ 28,393	$ 82,006	$ 23,343	$ 94,428	$ 180,000
2021	121,608	43,730	46,522	22,427	47,895	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
2022	5.28 %	0.10 %	2.15 %	2.15 %	2.23 %	2.15 %
2021	0.48 %	0.02 %	0.34 %	0.03 %	0.31 %	0.33 %

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest 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,	
	2022	2021
	(in thousands)	
Interest Expense	$ 1,985	$ 166
Interest Income	102	6

Securitized Accounts Receivables – AEP Credit

Under an affiliated receivables sales arrangement, KPCo sold, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit. KPCo was 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. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's statements of income. In January 2022, due to the pending sale to Liberty, KPCo ceased selling accounts receivable to AEP Credit. As a result, in the first quarter of 2022, KPCo began recording an allowance for uncollectible accounts on its balance sheet for those receivables no longer sold to AEP Credit.

KPCo's amounts of accounts receivable and accrued unbilled revenues under the sale of receivables agreement were $0 and $53.3 million as of December 31, 2022 and 2021, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $63 thousand and $1.9 million for the years ended December 31, 2022 and 2021, respectively. In 2021, due to the successful collection of accounts

receivable balances during the COVID-19 pandemic, the allowance for doubtful accounts was reduced, resulting in the issuance of credits to offset the higher fees previously paid and to lower subsequent fees paid. In 2022, as a result of KPCo's discontinued sale of receivables with AEP Credit, KPCo was issued a net credit upon final settlement of the allowance for doubtful accounts balance as collections of accounts receivable were higher than originally estimated.

KPCo's proceeds on the sale of receivables to AEP Credit were $66 million and $595 million for the years ended December 31, 2022 and 2021, respectively.

13. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "AEP System Tax Allocation" section of Note 1 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, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement.

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, while trading and marketing activities originating in SPP generally accrue to the benefit of PSO and SWEPCo. 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:

Related Party Revenues	Years Ended December 31, 2022	2021
	(in thousands)	
Transmission Agreement Sales	$ 17,701	$ 8,991
Other Revenues	1,550	1,551
Total Affiliated Revenues	$ 19,251	$ 10,542

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

Related Party Purchases	Years Ended December 31, 2022	2021
	(in thousands)	
Direct Purchases from AEGCo (a)	$ 93,137	$ 93,365
Total Affiliated Purchases	$ 93,137	$ 93,365

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

The above summarized related party revenues and expenses are reported in Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on KPCo's statements of income.

PJM Transmission Service Charges

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

KPCo's net charges recorded as a result of the TA for the years ended December 31, 2022 and 2021 were $64.9 million and $57.1 million, respectively, and were recorded in Other Operation expenses on KPCo's statements of income.

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. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all of its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The 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).

In April 2021, AEGCo and I&M executed an agreement to purchase 100% of the interests in Rockport Plant, Unit 2 effective at the end of the lease term on December 7, 2022. Beginning December 8, 2022, AEGCo and I&M applied the joint plant accounting model to their respective 50% undivided interests in the jointly owned Rockport Plant, Unit 2 as well as any future investments made prior to the current estimated retirement date of December 2028.

Prior to the termination of the lease, I&M assigned 30% of the power to KPCo. See the "UPA between AEGCo and KPCo" section below for additional information. Beginning December 8, 2022, AEGCo billed 100% of its share of the Rockport Plant to I&M and ceased billing to KPCo. KPCo reached an agreement with I&M, from the end of the lease through May 2024, to buy capacity from Rockport Plant, Unit 2 through the PCA at a rate equal to PJM's RPM clearing price.

UPA between AEGCo and KPCo

On December 7, 2022, the UPA between AEGCo and KPCo ended upon the termination of the Rockport Plant, Unit 2 lease. Previously, pursuant to an assignment between I&M and KPCo and a UPA between AEGCo and KPCo, AEGCo sold KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo paid 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. As a result of the end of the UPA between AEGCo and KPCo, a prorated bill was recorded from AEGCo to KPCo to reflect costs incurred for the first seven days of 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 $2 million and $3.1 million in 2022 and 2021, respectively, for urea transloading provided by I&M. These expenses were recorded as fuel expenses or other operation expenses. This agreement with KPCo terminated with the transfer of the Mitchell Plant in August 2022.

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 $1 million and $973 thousand for the years ended December 31, 2022 and 2021, 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 at net book value, as follows:

	Years Ended December 31,	
	2022	2021
	(in thousands)	
Sales	$ 1,187	$ 431
Purchases	631	3,995

The amounts above are recorded in Property, Plant and Equipment on the balance sheets.

Charitable Contributions to AEP Foundation

The American Electric Power Foundation is funded by American Electric Power and its utility operating units. The Foundation provides a permanent, ongoing resource for charitable initiatives and multi-year commitments in the communities served by AEP and initiatives outside of AEP's 11-state service area. In 2022, KPCo made a $2.8 million charitable contribution to the AEP Foundation recorded in Other Operation on the statements of income. In 2021, there were no charitable contributions made to the AEP Foundation.

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.

14. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a variable interest in a VIE. A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers whether KPCo has the power to direct the most significant activities of the VIE and is obligated to absorb losses or receive the expected residual returns that are significant to the VIE. Management believes that significant assumptions and judgments were applied consistently. KPCo is not the primary beneficiary of any VIE and has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. Parent is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct-charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the years ended December 31, 2022 and 2021 were $69.7 million and $75.2 million, respectively. The carrying amount of liabilities associated with AEPSC as of December 31, 2022 and 2021 were $6.1 million and $7.9 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant. In December 2022, the UPA between AEGCo and KPCo ended upon the termination of the Rockport Plant, Unit 2 lease. As a result, AEGCo began selling all of the output from the Rockport Plant to I&M, eliminating KPCo's significant variable interest in AEGCo as of December 31, 2022. KPCo was previously exposed to losses to the extent it could not recover the costs of AEGCo through its normal business operations. Total billings from AEGCo for the years ended December 31, 2022 and 2021 were $92.9 million and $93.4 million, respectively. The carrying amount of liabilities associated with AEGCo as of December 31, 2022 and 2021 were $2 million and $7.9 million, respectively.

15. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment is shown functionally on the face of KPCo's balance sheets. The following table includes KPCo's total plant balances as of December 31, 2022 and 2021:

	December 31, 2022	December 31, 2021
	(in thousands)	
Regulated Property, Plant and Equipment		
Generation	$ 1,236,474	$ 1,231,494
Transmission	801,838	760,359
Distribution	1,061,601	1,017,406
Other	166,754	129,250
CWIP	137,964	95,093
Less: Accumulated Depreciation	1,155,997	1,104,293
Total Regulated Property, Plant and Equipment - Net	2,248,634	2,129,309
Nonregulated Property, Plant and Equipment - Net	1,003	8,105
Total Property, Plant and Equipment - Net	$ 2,249,637	$ 2,137,414

Depreciation

KPCo provides for depreciation of Property, Plant and Equipment 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 2022 and 2021.

	2022		2021	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	3.0%	69 - 73	3.0%	69 - 73
Transmission	2.7%	37 - 75	2.6%	37 - 75
Distribution	3.4%	11 - 75	3.4%	11 - 75
Other	8.2%	5 - 75	9.5%	5 - 75

The composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization on the balance sheets. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability.

Asset Retirement Obligations (ARO)

The following is a reconciliation of the 2022 and 2021 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)			
2022	$ 17,697	$ 803	$ —	$ (1,162)	$ 1,139	$ 18,477
2021	24,565	968	—	(3,227)	(4,609)	17,697

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

Allowance for Funds Used During Construction

KPCo's amounts of allowance for equity and borrowed funds used during construction are summarized in the following table:

	Years Ended December 31, 2022	2021
	(in thousands)	
Allowance for Equity Funds Used During Construction	$ 1,192	$ 1,822
Allowance for Borrowed Funds Used During Construction	1,635	936

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 Property, Plant and Equipment 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, 2022					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,052,996	$ 23,231	$ 518,178
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

(a) In September 2022, pursuant to resolutions under the existing Mitchell Plant agreement, WPCo replaced KPCo as the operator of Mitchell Plant. See Note 1 - Organization and Summary of Significant Accounting Policies for additional information.

16. 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, 2022	2021
	(in thousands)	
Retail Revenues:		
Residential Revenues	$ 317,814	$ 282,900
Commercial Revenues	197,505	160,183
Industrial Revenues	185,174	142,217
Other Retail Revenues	2,193	2,029
Total Retail Revenues	702,686	587,329
Wholesale Revenues:		
Generation Revenues	29,680	29,523
Transmission Revenues (a)	35,522	22,052
Total Wholesale Revenues	65,202	51,575
Other Revenues from Contracts with Customers (b)	11,541	8,659
Total Revenues from Contracts with Customers	779,429	647,563
Other Revenues:		
Alternative Revenue Programs (c)	(6,216)	(1,180)
Other Revenues	8	—
Total Other Revenues	(6,208)	(1,180)
Total Revenues	$ 773,221	$ 646,383

(a) Amounts included affiliated and nonaffiliated revenues. The affiliated revenues were $19 million and $9 million for years ended December 31, 2022 and 2021, respectively.
(b) Amounts included affiliated and nonaffiliated revenues.
(c) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

Performance Obligations

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

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

Retail Revenues

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

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

Wholesale Revenues - Generation

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

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

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

Wholesale Revenues - Transmission

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

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

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

Fixed Performance Obligations

The following table represents KPCo's remaining fixed performance obligations satisfied over time as of December 31, 2022. Fixed performance obligations primarily include electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. KPCo elected to apply the exemption to not disclose the value of unsatisfied performance obligations for contracts with an original expected term of one year or less. Due to the annual establishment of revenue requirements, transmission revenues are excluded from the table below. The amounts shown in the table below include affiliated and nonaffiliated revenues.

2023	2024-2025	2026-2027	After 2027	Total
		(in thousands)		
$ 1,256	$ 2,512	$ 2,512	$ 1,256	$ 7,536

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, 2022 and 2021, 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, 2022 and 2021, respectively.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on KPCo's balance sheets within the Accounts Receivable - Customers line item. KPCo's balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of December 31, 2022 and 2021, 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 - Affiliated Companies on KPCo's balance sheets were $9.1 million and $9.1 million, respectively, as of December 31, 2022 and December 31, 2021.

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 and noncurrent assets 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 Other Operation on KPCo's statements of income. KPCo did not have material contract costs as of December 31, 2022 and 2021, respectively.

ANNEX 2

Kentucky Power Company

2023 First Quarter Report

Financial Statements

KENTUCKY POWER℠

An AEP Company

BOUNDLESS ENERGY℠

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GLOSSARY OF TERMS

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 consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
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.
Excess ADIT	Excess accumulated deferred income taxes.
FASB	Financial Accounting Standards Board.
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.
IRA	On August 16, 2022 President Biden signed into law legislation commonly referred to as the “Inflation Reduction Act” (IRA).
IRS	Internal Revenue Service.
ITC	Investment Tax Credit.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KTCo	AEP Kentucky Transmission Company, Inc., an affiliate of KPCo and a wholly-owned subsidiary of AEP.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
OPEB	Other Postretirement Benefits.
OTC	Over-the-counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PTC	Production Tax Credit.

Term	Meaning
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
RPM	Reliability Pricing Model.
ROE	Return on Equity.
Rockport Plant	A generation plant, jointly owned by AEGCo and I&M, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2023 and 2022
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2023	2022
REVENUES		
Electric Generation, Transmission and Distribution	$ 168,122	$ 176,497
Sales to AEP Affiliates	3,215	5,118
Other Revenues	195	822
TOTAL REVENUES	171,532	182,437
EXPENSES		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	73,366	51,776
Purchased Electricity from AEP Affiliates	977	24,450
Other Operation	29,227	32,155
Maintenance	17,849	14,430
Depreciation and Amortization	33,593	30,528
Taxes Other Than Income Taxes	7,561	6,759
TOTAL EXPENSES	162,573	160,098
OPERATING INCOME	8,959	22,339
Other Income (Expense):		
Interest Income	23	4
Allowance for Equity Funds Used During Construction	256	377
Non-Service Cost Components of Net Periodic Benefit Cost	1,894	1,622
Interest Expense	(15,174)	(9,165)
INCOME (LOSS) BEFORE INCOME TAX BENEFIT	(4,042)	15,177
Income Tax Benefit	(8,694)	(10,744)
NET INCOME	$ 4,652	$ 25,921

The common stock of KPCo is wholly-owned by Parent.

See Condensed Notes to Condensed Financial Statements beginning on page 9.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2023 and 2022
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2023	2022
Net Income	$ 4,652	$ 25,921
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $(10) in 2023 and 2022, Respectively	—	(39)
TOTAL COMPREHENSIVE INCOME	$ 4,652	$ 25,882

See Condensed Notes to Condensed Financial Statements beginning on page 9.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN
COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2023 and 2022
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2021	$ 50,450	$ 526,135	$ 296,021	$ 1,749	$ 874,355
Net Income			25,921		25,921
Other Comprehensive Loss				(39)	(39)
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2022	$ 50,450	$ 526,135	$ 321,942	$ 1,710	$ 900,237
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2022	$ 50,450	$ 526,287	$ 343,573	$ —	$ 920,310
Net Income			4,652		4,652
TOTAL COMMON SHAREHOLDER'S EQUITY - MARCH 31, 2023	$ 50,450	$ 526,287	$ 348,225	$ —	$ 924,962

See Condensed Notes to Condensed Financial Statements beginning on page 9.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2023 and December 31, 2022
(in thousands)
(Unaudited)

	March 31, 2023	December 31, 2022
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,828	$ 2,684
Accounts Receivable:		
Customers	43,662	63,432
Affiliated Companies	12,845	10,818
Accrued Unbilled Revenues	19,060	35,002
Miscellaneous	45	72
Allowance for Uncollectible Accounts	(704)	(1,013)
Total Accounts Receivable	74,908	108,311
Fuel	40,016	21,994
Materials and Supplies	22,933	26,182
Risk Management Assets	1,811	8,463
Regulatory Asset for Under-Recovered Fuel Costs	5,466	23,241
Margin Deposits	3,000	960
Prepayments and Other Current Assets	1,459	2,512
TOTAL CURRENT ASSETS	151,421	194,347
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,240,847	1,236,474
Transmission	806,327	801,838
Distribution	1,077,994	1,061,601
Other Property, Plant and Equipment	168,807	167,981
Construction Work in Progress	143,280	137,964
Total Property, Plant and Equipment	3,437,255	3,405,858
Accumulated Depreciation and Amortization	1,164,198	1,156,221
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	2,273,057	2,249,637
OTHER NONCURRENT ASSETS		
Regulatory Assets	502,242	504,185
Employee Benefits and Pension Assets	21,000	20,531
Operating Lease Assets	510	528
Deferred Charges and Other Noncurrent Assets	30,720	37,877
TOTAL OTHER NONCURRENT ASSETS	554,472	563,121
TOTAL ASSETS	$ 2,978,950	$ 3,007,105

See Condensed Notes to Condensed Financial Statements beginning on page 9.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2023 and December 31, 2022
(Unaudited)

	March 31, 2023	December 31, 2022
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 113,625	$ 94,428
Accounts Payable:		
General	38,094	56,969
Affiliated Companies	43,456	51,076
Long-term Debt Due Within One Year – Nonaffiliated	490,000	490,000
Customer Deposits	39,625	38,784
Accrued Taxes	29,040	40,272
Accrued Interest	9,204	8,543
Obligations Under Operating Leases	122	128
Other Current Liabilities	14,786	17,284
TOTAL CURRENT LIABILITIES	777,952	797,484
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	688,545	688,448
Deferred Income Taxes	451,457	456,217
Regulatory Liabilities and Deferred Investment Tax Credits	101,194	108,853
Asset Retirement Obligations	18,564	18,447
Employee Benefits and Pension Obligations	8,522	9,736
Obligations Under Operating Leases	438	450
Deferred Credits and Other Noncurrent Liabilities	7,316	7,160
TOTAL NONCURRENT LIABILITIES	1,276,036	1,289,311
TOTAL LIABILITIES	2,053,988	2,086,795
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	526,287	526,287
Retained Earnings	348,225	343,573
TOTAL COMMON SHAREHOLDER'S EQUITY	924,962	920,310
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,978,950	$ 3,007,105

See Condensed Notes to Condensed Financial Statements beginning on page 9.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2023 and 2022
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2023	2022
OPERATING ACTIVITIES		
Net Income	$ 4,652	$ 25,921
Adjustments to Reconcile Net Income to Net Cash Flows from (Used for) Operating Activities:		
Depreciation and Amortization	33,593	30,528
Deferred Income Taxes	(10,725)	(10,224)
Allowance for Equity Funds Used During Construction	(256)	(377)
Mark-to-Market of Risk Management Contracts	7,462	4,509
Property Taxes	6,516	5,391
Deferred Fuel Over/Under-Recovery, Net	17,775	(7,336)
Change in Other Noncurrent Assets	(6,553)	(6,874)
Change in Other Noncurrent Liabilities	(7,067)	(2,404)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	33,563	(39,499)
Fuel, Materials and Supplies	(14,780)	(6,776)
Margin Deposits	(2,040)	12,782
Accounts Payable	(27,525)	(4,251)
Accrued Taxes, Net	(10,517)	(12,238)
Other Current Assets	353	685
Other Current Liabilities	(1,324)	7,528
Net Cash Flows from (Used for) Operating Activities	23,127	(2,635)
INVESTING ACTIVITIES		
Construction Expenditures	(43,547)	(41,950)
Other Investing Activities	389	1,015
Net Cash Flows Used for Investing Activities	(43,158)	(40,935)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	19,197	46,044
Principal Payments for Finance Lease Obligations	(22)	(230)
Other Financing Activities	—	(34)
Net Cash Flows from Financing Activities	19,175	45,780
Net Increase (Decrease) in Cash and Cash Equivalents	(856)	2,210
Cash and Cash Equivalents at Beginning of Period	2,684	763
Cash and Cash Equivalents at End of Period	$ 1,828	$ 2,973
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 14,173	$ 8,594
Noncash Acquisitions Under Finance Leases	—	77
Construction Expenditures Included in Current Liabilities as of March 31,	19,511	25,246

See Condensed Notes to Condensed Financial Statements beginning on page 9.

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1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair statement of the net income, financial position and cash flows for the interim periods. Net income for the three months ended March 31, 2023 is not necessarily indicative of results that may be expected for the year ending December 31, 2023. The condensed financial statements are unaudited and should be read in conjunction with the audited 2022 financial statements and notes thereto, which are included in KPCo's 2022 Annual Report.

Termination of Planned Disposition of KPCo and KTCo

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

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

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

Subsequent Events

Management reviewed subsequent events through May 4, 2023, the date that the first quarter 2023 report was available to be issued.

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. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 6 - Benefit Plans for additional information.

Three Months Ended March 31, 2023	Pension and OPEB
	(in thousands)
Balance in AOCI as of December 31, 2022	$ —
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	—
Amortization of Actuarial (Gains) Losses	—
Reclassifications from AOCI, before Income Tax (Expense) Benefit	—
Income Tax (Expense) Benefit	—
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	—
Net Current Period Other Comprehensive Income (Loss)	—
Balance in AOCI as of March 31, 2023	$ —

Three Months Ended March 31, 2022	Pension and OPEB
	(in thousands)
Balance in AOCI as of December 31, 2021	$ 1,749
Change in Fair Value Recognized in AOCI	—
Amount of (Gain) Loss Reclassified from AOCI	
Amortization of Prior Service Cost (Credit)	(59)
Amortization of Actuarial (Gains) Losses	10
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(49)
Income Tax (Expense) Benefit	(10)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(39)
Net Current Period Other Comprehensive Income (Loss)	(39)
Balance in AOCI as of March 31, 2022	$ 1,710

4. RATE MATTERS

As discussed in KPCo's 2022 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2022 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2023 and updates KPCo's 2022 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	March 31, 2023	December 31, 2022
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Storm-Related Costs (a)	$ 73,936	$ 74,430
Other Regulatory Assets Pending Final Regulatory Approval	1,914	1,699
Total Regulatory Assets Pending Final Regulatory Approval	$ 75,850	$ 76,129

(a) KPCo will seek recovery of these costs in a future regulatory proceeding. In March 2023, Kentucky (Senate Bill 192) passed legislation that would allow the securitization of certain retired generation costs with a minimum value of $200 million, as well as certain other regulatory assets including deferred extraordinary storm costs, as long as the cumulative total requested for securitization is at least $275 million.

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

Storm-Related Costs

In March and April 2023, major storms impacted KPCo's service territory resulting in system damages and power outages. As of March 31, 2023, KPCo incurred approximately $3 million of incremental other operating and maintenance expenses related to the March 2023 storms. Management estimates KPCo will incur an additional $6 million of other operating and maintenance expenses related to additional April 2023 storms. Consistent with prior guidance from the KPSC, KPCo filed an application with the KPSC seeking recovery of these prudently incurred costs in May 2023. Until KPCo receives deferral authority for these incremental storm costs from the KPSC, it will reduce net income and cash flows and impact financial condition.

Deferred Purchased Power Expenses

In September 2022, the KPSC initiated a proceeding to investigate the appropriate amortization period and recovery mechanism for the deferral of Kentucky Deferred Purchased Power Expenses related to the Rockport Plant Unit Power Agreement (UPA), as well as KPCo's ability to use the level of non-fuel, non-environmental Rockport UPA expense included in base rates to earn its authorized ROE in 2023 since the KPCo UPA ended in December 2022. KPCo requested the KPSC approve the terms related to each of the foregoing items as reflected in the settlement agreement in the 2017 Kentucky Base Rate Case, including recovery of the Kentucky Deferred Purchased Power Expenses over five years through a rider beginning in December 2022. In December 2022, the KPSC approved KPCo's request and recovery began through a rider, including recovery of an estimated allowed cost (Rockport Offset) of $22.8 million in accordance with the terms of the settlement agreement in the 2017 Kentucky Base Rate Case permitting KPCo to use the level of non-fuel, non-environmental Rockport UPA expense included in base rates to earn its authorized ROE in 2023. This estimated Rockport Offset is subject to true-up based on KPCo's actual 2023 financial results and KPSC review in the first quarter of 2024. The actual Rockport Offset cannot exceed $40.8 million. If the actual Rockport Offset is not recoverable, it could reduce future net income and cash flows and impact financial condition.

Fuel Adjustment Clause (FAC) Purchased Power Limitation

In May 2023, KPCo filed an application seeking authority to defer, for future recovery, approximately $11.5 million of December 2022 purchased power costs not recoverable through its FAC. This requested deferral accounting authority would enable KPCo to pursue securitization of these costs, which otherwise would be requested for recovery in KPCo's next base rate case, in a future proceeding pursuant to Kentucky Senate Bill 192. Until KPCo receives deferral authority for these purchased power costs from the KPSC, it will reduce net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo's 2022 Annual Report should be read in conjunction with this report.

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 March 31, 2023, 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.

6. BENEFIT PLANS

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

Components of Net Periodic Benefit Cost

The following table provides the components of KPCo's net periodic benefit cost (credit) for the plans:

	Pension Plans		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2023	2022	2023	2022
	(in thousands)			
Service Cost	$ 368	$ 791	$ 16	$ 52
Interest Cost	1,204	1,288	317	261
Expected Return on Plan Assets	(1,783)	(2,400)	(800)	(1,060)
Amortization of Prior Service Credit	—	—	(464)	(630)
Amortization of Net Actuarial Loss	—	536	111	—
Net Periodic Benefit Cost (Credit)	$ (211)	$ 215	$ (820)	$ (1,377)

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of KPCo.

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

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

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

Primary Risk Exposure	March 31, 2023	December 31, 2022	Unit of Measure
	(in thousands)		
Commodity:			
Power	1,400	3,450	MWhs

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. The amount of cash collateral received from third-parties netted against short-term and long-term risk management assets and the amount of cash collateral paid to third-parties netted against short-term and long-term risk management liabilities were immaterial for KPCo as of March 31, 2023 and December 31, 2022.

The following tables represent the gross fair value of KPCo's derivative activity on the balance sheets. Unless shown as a separate line on the balance sheets due to materiality, Current Risk Management Assets are included in Prepayments and Other Current Assets, Long-term Risk Management Assets are included in Deferred Charges and Other Noncurrent Assets, Current Risk Management Liabilities are included in Other Current Liabilities and Long-term Risk Management Liabilities are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

	March 31, 2023		
Balance Sheet Location	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)	
Current Risk Management Assets	$ 1,894	$ (83)	$ 1,811
Long-term Risk Management Assets	92	(92)	—
Total Assets	1,986	(175)	1,811
Current Risk Management Liabilities	879	(83)	796
Long-term Risk Management Liabilities	92	(92)	—
Total Liabilities	971	(175)	796
Total MTM Derivative Contract Net Assets (d)	$ 1,015	$ —	$ 1,015

	December 31, 2022		
Balance Sheet Location	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)	
Current Risk Management Assets	$ 8,607	$ (144)	$ 8,463
Long-term Risk Management Assets	137	(137)	—
Total Assets	8,744	(281)	8,463
Current Risk Management Liabilities	144	(144)	—
Long-term Risk Management Liabilities	137	(137)	—
Total Liabilities	281	(281)	—
Total MTM Derivative Contract Net Assets	$ 8,463	$ —	$ 8,463

(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.
(d) Decrease in amounts as of March 31, 2023 are primarily due to decreases in commodity prices for power and natural gas and a decrease in value of FTRs.

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

Amount of Gain (Loss) Recognized on Risk Management Contracts

	Three Months Ended March 31,	
Location of Gain (Loss)	2023	2022
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ —	$ 2
Purchased Electricity for Resale	19	59
Other Operation	—	16
Maintenance	—	21
Regulatory Assets (a)	(796)	(46)
Regulatory Liabilities (a)	(2,687)	1,566
Total Gain (Loss) on Risk Management Contracts	$ (3,464)	$ 1,618

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

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 (Loss) 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 Total Revenues or Purchased Electricity for Resale on KPCo's statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2023 and 2022, 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 (Loss) on its balance sheets into Interest Expense on its statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2023 and 2022, 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 (Loss) on KPCo's balance sheets as of March 31, 2023 and December 31, 2022.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes. As of March 31, 2023, 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 March 31, 2023 and December 31, 2022, KPCo did not have derivative contracts with collateral triggering events in a net liability position.

Cross-Acceleration Triggers

Certain interest rate derivative contracts contain cross-acceleration provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-acceleration provisions could be triggered if there was a non-performance event by KPCo under any of their outstanding debt of at least $50 million and the lender on that debt has accelerated the entire repayment obligation. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-acceleration provisions in contracts. KPCo had no derivative contracts with cross-acceleration provisions in a net liability position as of March 31, 2023 and December 31, 2022, respectively. There was no cash collateral posted as of March 31, 2023 and December 31, 2022. If a cross-acceleration provision would have been triggered, settlement at fair value would have been required. KPCo had no derivative contracts with cross-acceleration provisions outstanding as of March 31, 2023 and December 31, 2022.

Cross-Default Triggers

In addition, a majority of KPCo's non-exchange-traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third-party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. KPCo had no derivative contracts with cross-default provisions outstanding as of March 31, 2023 and December 31, 2022. There was no cash collateral posted as of March 31, 2023 and December 31, 2022. If a cross-default provision would have been triggered, settlement at fair value would have been required.

8. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

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.

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:

	March 31, 2023		December 31, 2022	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 1,178,545	$ 1,160,981	$ 1,178,448	$ 1,148,769

Fair Value Measurements of Financial Assets and Liabilities

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
March 31, 2023

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 81	$ 1,824	$ (94)	$ 1,811
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 81	$ 809	$ (94)	$ 796

December 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 137	$ 8,607	$ (281)	$ 8,463
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 137	$ 144	$ (281)	$ —

(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:

Three Months Ended March 31, 2023	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2022	$ 8,463
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(2,742)
Settlements	(3,984)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(722)
Balance as of March 31, 2023	$ 1,015

Three Months Ended March 31, 2022	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2021	$ 5,871
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	1,021
Settlements	(5,960)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	449
Balance as of March 31, 2022	$ 1,381

(a) Included in revenues on KPCo's statements of income.

(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.

(c) Relates to the net gains (losses) of those contracts that are not reflected on KPCo's statements of income. These changes in fair value are recorded as regulatory liabilities for net gains and as regulatory assets for net losses.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
March 31, 2023

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in thousands)						
FTRs	$ 1,824	$ 809	Discounted Cash Flow	Forward Market Price	$ (1.78)	$ 6.29	$ 0.73

December 31, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in thousands)						
FTRs	$ 8,607	$ 144	Discounted Cash Flow	Forward Market Price	$ (3.10)	$ 18.79	$ 2.48

(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 March 31, 2023 and December 31, 2022:

Uncertainty of Fair Value Measurements

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

9. INCOME TAXES

Effective Tax Rates (ETR)

KPCo accounts for income taxes in interim periods in accordance with the accounting guidance for "Income Taxes." In accordance with the guidance the use of an estimated annual effective tax rate should be utilized to determine income tax expense unless a reliable estimate of the annual effective tax rate cannot be made, in which case the actual effective tax rate for the year to date should be utilized. KPCo's interim ETR reflects the actual year-to-date effective tax rate for 2023 and the estimated annual ETR for 2022, adjusted for tax expense associated with certain discrete items.

KPCo includes the amortization of Excess ADIT not subject to normalization requirements in the estimated annual ETR when regulatory proceedings instruct KPCo to provide the benefits of Tax Reform to customers over multiple interim periods. Certain regulatory proceedings instruct KPCo to provide the benefits of Tax Reform to customers in a single period (e.g. by applying the Excess ADIT not subject to normalization requirements against an existing regulatory asset balance) and in these circumstances, KPCo recognizes the tax benefit discretely in the period recorded. The annual amount of Excess ADIT approved by KPCo's regulatory commissions may not impact the ETR ratably during each interim period due to the variability of pretax book income between interim periods and the application of an estimated annual ETR.

The ETR for KPCo is included in the following table:

	Three Months Ended March 31,	
	2023	2022
U.S. Federal Statutory Rate	21.0 %	21.0 %
Increase (decrease) due to:		
State Income Tax, net of Federal Benefit	(4.9)%	(0.9)%
Tax Reform Excess ADIT Reversal	193.5 %	(89.7)%
Flow Through	6.4 %	0.1 %
AFUDC Equity	1.3 %	(1.4)%
Other	(2.2)%	0.1 %
Effective Income Tax Rate	215.1 %	(70.8)%

Federal and State 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. KPCo and other AEP subsidiaries have agreed to extend the statute of limitations on the 2017 and 2018 tax returns to December 31, 2023, to allow time for the current IRS audit to be completed including a refund claim approval by the Congressional Joint Committee on Taxation. The statute of limitations for the 2019 return is set to naturally expire in 2023 as well.

The current IRS audit and associated refund claim evolved from a net operating loss carryback to 2015 that originated in the 2017 return. KPCo and other AEP subsidiaries have received and agreed to two IRS proposed adjustments on the 2017 tax return, which were immaterial. The exam is nearly complete, and KPCo and other AEP subsidiaries are currently working with the IRS to submit the refund claim to the Congressional Joint Committee on Taxation for resolution and final approval.

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. Generally, the statutes of limitations have expired for tax years prior to 2017. In addition, management is monitoring and continues to evaluate the potential impact of federal legislation and corresponding state conformity.

Federal Legislation

In August 2022, President Biden signed H.R. 5376 into law, commonly known as the Inflation Reduction Act of 2022 or IRA. Most notably this budget reconciliation legislation creates a 15% minimum tax on adjusted financial statement income (Corporate Alternative Minimum Tax or CAMT), extends and increases the value of PTCs and ITCs, adds a nuclear and clean hydrogen PTC, an energy storage ITC and allows the sale or transfer of tax credits to third parties for cash. As further significant guidance from Treasury and the IRS is expected on the tax provisions in the IRA, KPCo and other AEP subsidiaries will continue to monitor any issued guidance and evaluate the impact on future net income, cash flows and financial condition.

In December 2022, the IRS released Notice 2023-7 addressing time sensitive issues related to the CAMT. The notice provided initial guidance that KPCo and other AEP subsidiaries can begin to rely on in 2023 and also stated that additional guidance is expected, of which KPCo and other AEP subsidiaries will continue to monitor and assess. Notably, the interim guidance in Notice 2023-7 confirmed the CAMT depreciation adjustment includes tax depreciation that is capitalized to inventory under §263A and recovered as part of cost of goods sold, providing significant relief to KPCo and other AEP subsidiaries's potential CAMT exposure.

KPCo and other AEP subsidiaries expect to be applicable corporations for purposes of the CAMT beginning in 2023. CAMT cash taxes are expected to be partially offset by regulatory recovery, the utilization of tax credits and additionally the cash inflow generated by the sale of tax credits. The sale of tax credits will be presented in the operating section of the statements of cash flows consistent with the presentation of cash taxes paid. KPCo and other AEP subsidiaries will present the gain or loss on sale of tax credits through income tax expense.

10. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first three months of 2023.

Dividend Restrictions

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

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

KPCo has credit agreements that contain a covenant that limit its debt to capitalization ratio to 67.5%. As of March 31, 2023, 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 Federal Power Act restriction does not limit the ability of KPCo 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 its agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of March 31, 2023 and December 31, 2022 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limit for the three months ended March 31, 2023 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Average Borrowings from the Utility Money Pool	Borrowings from the Utility Money Pool as of March 31, 2023	Authorized Short-Term Borrowing Limit
		(in thousands)	
$ 124,006	$ 109,635	$ 113,625	$ 180,000

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

Three Months Ended March 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool
2023	5.42 %	4.66 %	5.12 %
2022	1.00 %	0.10 %	0.67 %

Securitized Accounts Receivables – AEP Credit

Under an affiliated receivables sales arrangement, KPCo sold, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit. KPCo was 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. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's statements of income. In January 2022, due to the expected sale to Liberty, KPCo ceased selling accounts receivable to AEP Credit. As a result, in the first quarter of 2022, KPCo began recording an allowance for uncollectible accounts on its balance sheet for those receivables no longer sold to AEP Credit.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended March 31, 2023 and 2022 were $0 and $295 thousand, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended March 31, 2023 and 2022 were $0 and $65.6 million, respectively.

11. 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:

	Three Months Ended March 31,	
	2023	2022
	(in thousands)	
Retail Revenues:		
Residential Revenues	$ 71,885	$ 81,690
Commercial Revenues	43,269	44,071
Industrial Revenues	41,567	39,650
Other Retail Revenues	544	538
Total Retail Revenues	157,265	165,949
Wholesale Revenues:		
Generation Revenues	3,336	4,618
Transmission Revenues (a)	7,300	7,851
Total Wholesale Revenues	10,636	12,469
Other Revenues from Contracts with Customers (b)	2,472	3,819
Total Revenues from Contracts with Customers	170,373	182,237
Other Revenues:		
Alternative Revenue Programs (c)	1,159	198
Other Revenues	—	2
Total Other Revenues	1,159	200
Total Revenues	$ 171,532	$ 182,437

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues were $3.8 million and $4.7 million for the three months ended March 31, 2023 and 2022, respectively.
(b) Amounts include affiliated and nonaffiliated revenues.
(c) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

Fixed Performance Obligations

The following table represents KPCo's remaining fixed performance obligations satisfied over time as of March 31, 2023. Fixed performance obligations primarily include electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. KPCo elected to apply the exemption to not disclose the value of unsatisfied performance obligations for contracts with an original expected term of one year or less. Due to the annual establishment of revenue requirements, transmission revenues are excluded from the table below. The amounts shown in the table below include affiliated and nonaffiliated revenues.

2023	2024-2025	2026-2027	After 2027	Total
		(in thousands)		
$ 942	$ 2,512	$ 2,512	$ 1,256	$ 7,222

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 March 31, 2023 and December 31, 2022, 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 March 31, 2023 and December 31, 2022, respectively.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on KPCo's balance sheets within the Accounts Receivable - Customers line item. KPCo's balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of March 31, 2023 and December 31, 2022. See "Securitized Accounts Receivable - AEP Credit" section of Note 10 for additional information related to AEP Credit's securitized accounts receivable.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on KPCo's balance sheets were $10.6 million and $9.1 million, respectively, as of March 31, 2023 and December 31, 2022.

APPENDIX B-1

FORM OF ORIGINAL OPINION OF BOND COUNSEL

June 26, 2014

West Virginia Economic Development Authority
Charleston, West Virginia

West Virginia Economic Development Authority
$65,000,000
Solid Waste Disposal Facilities Revenue Refunding Bonds
(Kentucky Power Company - Mitchell Project), Series 2014A

We have examined the transcript of proceedings relating to the issuance by the West Virginia Economic Development Authority (the "Issuer") of $65,000,000 principal amount of Solid Waste Disposal Facilities Revenue Refunding Bonds (Kentucky Power Company – Mitchell Project), Series 2014A (the "Bonds"). The Bonds are being issued pursuant to Chapter 31, Article 15, Section 1, et seq., of the Code of West Virginia, 1931 (the "Act"), for the purpose of making a loan to assist Kentucky Power Company (the "Company") in the refunding of $65,000,000 Solid Waste Disposal Facilities Revenue Refunding Bonds (Ohio Power Company – Mitchell Project), Series 2008A, previously issued by the Issuer to assist a certain affiliate of the Company in refinancing of a portion of the costs of acquiring, constructing and installing certain solid waste disposal facilities qualified for financing under the Act, as more particularly described in the Indenture of Trust dated as of June 15, 2014 (the "Indenture") between the Issuer and The Bank of New York Mellon Trust Company, N.A., as trustee (the "Trustee"), and in the Loan Agreement dated as of June 15, 2014 (the "Agreement") between the Issuer and the Company. We have also examined executed counterparts of the Indenture and the Agreement and a conformed copy of an executed Bond.

Based on such examination and subject to the limitations stated below, we are of the opinion that, under existing law:

1. The Bonds, the Indenture and the Agreement are valid and binding obligations of the Issuer, enforceable in accordance with their respective terms.

2. The Bonds constitute special obligations of the Issuer, and the principal of and interest on the Bonds and the purchase price of the Bonds (collectively, "debt charges") are payable solely from the revenues and other moneys assigned by the Indenture to secure those payments. Those revenues and other moneys include the payments required to be made by the Company under its promissory note delivered to the Issuer, and irrevocably assigned by the Issuer to the

Trustee, all pursuant to the Agreement. The payment of debt service on the Bonds is not secured by an obligation or pledge of any money raised by taxation, and the Bonds do not represent or constitute a general obligation or a pledge of the faith and credit of the Issuer, the State of West Virginia or any of its political subdivisions.

3. Interest on the Bonds is excluded from gross income for federal income tax purposes under Section 103(a) of the Internal Revenue Code of 1986, as amended (the "Code"), except interest on any Bond for any period during which it is held by a "substantial user" or a "related person" as those terms are used in Section 147(a) of the Code, and is an item of tax preference for purposes of the federal alternative minimum tax imposed on individuals and corporations. The Bonds, and all interest and income thereon, are exempt from all taxation by the State of West Virginia and any county, municipality, political subdivision or agency thereof, except inheritance taxes. We express no opinion as to any other tax consequences regarding the Bonds.

The opinions stated above are based on an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. In rendering all such opinions, we assume, without independent verification, and rely upon (i) the accuracy of the factual matters represented, warranted or certified in the proceedings and documents we have examined, (ii) the due and legal authorization, execution and delivery of those documents by, and the valid, binding and enforceable nature of those documents upon, any parties other than the Issuer and (iii) the correctness of the legal conclusions contained in the legal opinion letter of counsel to the Company and in the legal opinion letter of counsel to the Issuer delivered in connection with this matter.

In rendering those opinions with respect to the treatment of the interest on the Bonds under the federal tax laws, we further assume and rely upon compliance with the covenants in the proceedings and documents we have examined, including those of the Issuer and the Company. Failure to comply with certain of those covenants subsequent to issuance of the Bonds may cause interest on the Bonds to be included in gross income for federal income tax purposes retroactively to their date of issuance.

The rights of the owners of the Bonds and the enforceability of the Bonds, the Indenture and the Agreement are subject to bankruptcy, insolvency, arrangement, fraudulent conveyance or transfer, reorganization, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion, and to limitations on legal remedies against public entities.

We express no opinion with respect to any indemnification, contribution, penalty, choice of law, choice of forum, choice of venue, waiver or severability provisions contained in the Bonds, the Indenture or the Agreement.

The opinions rendered in this letter are stated only as of this date, and no other opinion shall be implied or inferred as a result of anything contained in or omitted from this letter. Our engagement as bond counsel with respect to the Bonds has concluded on this date.

Respectfully submitted,

Very truly yours,

APPENDIX B-2

PROPOSED FORM OF OPINION OF BOND COUNSEL UPON REMARKETING

June 6, 2023

West Virginia Economic Development Authority
Charleston, West Virginia

The Bank of New York Mellon Trust Company, N.A., as Trustee
Columbus, Ohio

Kentucky Power Company
c/o American Electric Power Service Corporation
Columbus, Ohio

This opinion is rendered at the request of Kentucky Power Company (the "Company") in connection with the delivery of a notice regarding the change in interest rate Determination Method on the Bonds (identified below) from the Long-Term Interest Rate to another Long-Term Interest Rate to be effective on June 20, 2023 (the "Action"). The Bonds are the $65,000,000 West Virginia Economic Development Authority Solid Waste Disposal Facilities Revenue Refunding Bonds (Kentucky Power Company – Mitchell Project), Series 2014A (the "Bonds"). The Bonds were issued pursuant to the Indenture of Trust dated as of June 15, 2014 (the "Indenture") between the West Virginia Economic Development Authority and The Bank of New York Mellon Trust Company, N.A., as Trustee. Capitalized terms not otherwise defined in this opinion are used as defined in the Indenture.

In our capacity as bond counsel, we have examined such proceedings, documents, matters and law as we deem necessary to render the opinions set forth in this letter.

Based on that examination and subject to the limitations stated below, we are of the opinion that under existing law:

(1) The Action is permitted under the Act and by the Indenture; and

(2) The Action will not, by itself, adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes.

The opinions stated above are based on an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. In rendering all such opinions we assume, without independent verification, and rely upon the accuracy of the factual matters represented, warranted or certified in the proceedings and documents we have examined.

The opinion stated above regarding treatment of interest on the Bonds for federal income tax purposes is limited to the legal effect of the Action. We delivered our opinion letter as bond

counsel to the Issuer dated June 26, 2014 (the "Bond Opinion") in connection with the original issuance of the Bonds. The Bond Opinion speaks only as of its date and this letter is not a confirmation or renewal of the Bond Opinion as of any more recent date. We have not for purposes of this letter examined any of the matters of law or fact upon which the legal opinions expressed in the Bond Opinion were based. We have not for purposes of this letter obtained, verified or reviewed any information concerning any event, other than the Action and the actions described in our opinions dated May 30, 2017, June 19, 2017, May 18, 2020, and June 19 2020, related to the Bonds, that might have occurred subsequent to the original issuance of the Bonds and that might have adversely affected the exclusion from gross income of interest on the Bonds for federal income tax purposes. Accordingly, except as expressly stated above, we express no opinion as to any matters concerning the status of the interest on the Bonds under the Internal Revenue Code of 1986, as amended, including specifically whether the interest on the Bonds is excluded from gross income for federal income tax purposes.

This letter is being furnished only to you for your use solely in connection with the Action and may not be relied upon by anyone else or for any other purpose without our prior written consent. No opinions other than those expressly stated herein are implied or shall be inferred as a result of anything contained in or omitted from this letter. The opinions expressed in this letter are stated only as of the time of its delivery, and we disclaim any obligation to revise or supplement this letter thereafter.

Respectfully submitted,

Confidential Exhibit P pages 148 through 337 are confidential in their entirety.

Kentucky Power Company

2023 Annual Report

Audited Financial Statements

KENTUCKY POWER℠

An AEP Company

BOUNDLESS ENERGY℠

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GLOSSARY OF TERMS

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 consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated VIE of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KGPCo, KPCo, OPCo and WPCo.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AFUDC	Allowance for Equity Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ASU	Accounting Standards Update.
CCR	Coal Combustion Residual.
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.
ELG	Effluent Limitation Guidelines.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE of AEP.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KTCo	AEP Kentucky Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
Liberty	Liberty Utilities Co., a subsidiary of Algonquin Power & Utilities Corporation.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NOLC	Net operating loss carryforwards.
NO_x	Nitrogen oxide.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.

Term	Meaning
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third-party sales. AEPSC acts as the agent.
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, jointly-owned by AEGCo and I&M, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TA	Transmission Agreement, effective November 2010, among APCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	West Virginia Public Service Commission.

Report of Independent Auditors

To the Management and Board of Directors of Kentucky Power Company

Opinion

We have audited the accompanying financial statements of Kentucky Power Company (the "Company"), which comprise the balance sheets as of December 31, 2023 and 2022, and the related statements of income, of comprehensive income (loss), of changes in common shareholder's equity and of cash flows for the years then ended, including the related notes (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date the financial statements are available to be issued.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

PricewaterhouseCoopers LLP

Columbus, Ohio
February 26, 2024

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2023 and 2022
(in thousands)

	Years Ended December 31, 2023	2022
REVENUES		
Electric Generation, Transmission and Distribution	$ 602,847	$ 752,371
Sales to AEP Affiliates	11,173	19,251
Other Revenues	829	1,599
TOTAL REVENUES	614,849	773,221
EXPENSES		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	226,287	277,291
Purchased Electricity from AEP Affiliates	1,968	93,137
Other Operation	106,883	133,992
Maintenance	64,173	64,821
Depreciation and Amortization	123,639	123,238
Taxes Other Than Income Taxes	27,545	26,919
TOTAL EXPENSES	550,495	719,398
OPERATING INCOME	64,354	53,823
Other Income (Expense):		
Interest Income	202	134
Allowance for Equity Funds Used During Construction	968	1,192
Non-Service Cost Components of Net Periodic Benefit Cost	7,576	6,490
Interest Expense	(66,813)	(45,115)
INCOME BEFORE INCOME TAX BENEFIT	6,287	16,524
Income Tax Benefit	(27,675)	(31,028)
NET INCOME	$ 33,962	$ 47,552

The common stock of KPCo is wholly-owned by Parent.

See Notes to Financial Statements beginning on page 11.

KENTUCKY POWER COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2023 and 2022
(in thousands)

	Years Ended December 31, 2023	2022
Net Income	$ 33,962	$ 47,552
OTHER COMPREHENSIVE LOSS, NET OF TAXES		
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0 and $(21) in 2023 and 2022, Respectively	—	(79)
Pension and OPEB Adjustment Related to Plant Transfers, Net of Tax of $0 and $(444) in 2023 and 2022, Respectively	—	(1,670)
TOTAL OTHER COMPREHENSIVE LOSS	—	(1,749)
TOTAL COMPREHENSIVE INCOME	$ 33,962	$ 45,803

See Notes to Financial Statements beginning on page 11.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2023 and 2022
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2021	$ 50,450	$ 526,135	$ 296,021	$ 1,749	$ 874,355
Capital Contribution from Parent		152			152
Net Income			47,552		47,552
Other Comprehensive Loss				(1,749)	(1,749)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	50,450	526,287	343,573	—	920,310
Capital Contribution from Parent		868			868
Return of Capital to Parent		(384)			(384)
Net Income			33,962		33,962
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2023	$ 50,450	$ 526,771	$ 377,535	$ —	$ 954,756

See Notes to Financial Statements beginning on page 11.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2023 and 2022
(in thousands)

	December 31, 2023	December 31, 2022
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,321	$ 2,684
Accounts Receivable:		
Customers	17,723	63,432
Affiliated Companies	24,213	10,818
Accrued Unbilled Revenues	—	35,002
Miscellaneous	117	72
Allowance for Uncollectible Accounts	—	(1,013)
Total Accounts Receivable	42,053	108,311
Fuel	80,638	21,994
Materials and Supplies	25,445	26,182
Risk Management Assets	3,064	8,463
Regulatory Asset for Under-Recovered Fuel Costs	10,688	23,241
Margin Deposits	2,926	960
Prepayments and Other Current Assets	15,027	2,512
TOTAL CURRENT ASSETS	181,162	194,347
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,239,925	1,236,474
Transmission	838,264	801,838
Distribution	1,119,303	1,061,601
Other Property, Plant and Equipment	175,031	167,981
Construction Work in Progress	159,612	137,964
Total Property, Plant and Equipment	3,532,135	3,405,858
Accumulated Depreciation and Amortization	1,205,973	1,156,221
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	2,326,162	2,249,637
OTHER NONCURRENT ASSETS		
Regulatory Assets	548,225	504,185
Deferred Charges and Other Noncurrent Assets	78,479	58,936
TOTAL OTHER NONCURRENT ASSETS	626,704	563,121
TOTAL ASSETS	$ 3,134,028	$ 3,007,105

See Notes to Financial Statements beginning on page 11.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2023 and 2022
(dollars in thousands)

	December 31, 2023	December 31, 2022
CURRENT LIABILITIES		
Advances from Affiliates	$ 49,567	$ 94,428
Accounts Payable:		
General	36,823	56,969
Affiliated Companies	46,018	51,076
Long-term Debt Due Within One Year – Nonaffiliated	215,000	490,000
Risk Management Liabilities	7,926	—
Customer Deposits	38,027	38,784
Accrued Taxes	49,490	40,272
Obligations Under Operating Leases	195	128
Other Current Liabilities	44,610	25,827
TOTAL CURRENT LIABILITIES	487,656	797,484
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,059,806	688,448
Long-term Debt – Affiliated	25,000	—
Deferred Income Taxes	473,843	456,217
Regulatory Liabilities	97,627	108,853
Asset Retirement Obligations	18,071	18,447
Employee Benefits and Pension Obligations	9,581	9,736
Obligations Under Operating Leases	963	450
Deferred Credits and Other Noncurrent Liabilities	6,725	7,160
TOTAL NONCURRENT LIABILITIES	1,691,616	1,289,311
TOTAL LIABILITIES	2,179,272	2,086,795
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	526,771	526,287
Retained Earnings	377,535	343,573
TOTAL COMMON SHAREHOLDER'S EQUITY	954,756	920,310
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 3,134,028	$ 3,007,105

See Notes to Financial Statements beginning on page 11.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2023 and 2022
(in thousands)

	Years Ended December 31, 2023	2022
OPERATING ACTIVITIES		
Net Income	$ 33,962	$ 47,552
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	123,639	123,238
Deferred Income Taxes	(26,059)	(31,793)
Allowance for Equity Funds Used During Construction	(968)	(1,192)
Mark-to-Market of Risk Management Contracts	14,299	(2,542)
Pension and Postemployment Benefit Reserves	(4,122)	31,242
Deferred Fuel Over/Under-Recovery, Net	12,554	(15,025)
Change in Regulatory Assets	(32,887)	(28,263)
Change in Other Noncurrent Assets	(27,547)	(5,950)
Change in Other Noncurrent Liabilities	(8,971)	5,339
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	66,899	(49,138)
Fuel, Materials and Supplies	(57,893)	(17,492)
Margin Deposits	(1,966)	13,269
Accounts Payable	(23,149)	22,773
Accrued Taxes, Net	9,403	(4,843)
Other Current Assets	(685)	777
Other Current Liabilities	4,657	(3,198)
Net Cash Flows from Operating Activities	81,166	84,754
INVESTING ACTIVITIES		
Construction Expenditures	(159,770)	(210,346)
Proceeds from Sales of Assets	115	8,004
Other Investing Activities	766	685
Net Cash Flows Used for Investing Activities	(158,889)	(201,657)
FINANCING ACTIVITIES		
Capital Contribution from Parent	868	152
Return of Capital to Parent	(384)	—
Issuance of Long-term Debt - Nonaffiliated	435,798	149,869
Issuance of Long-term Debt - Affiliated	25,000	—
Change in Advances from Affiliates, Net	(44,861)	46,533
Retirement of Long-term Debt - Nonaffiliated	(340,000)	(75,000)
Principal Payments for Finance Lease Obligations	(83)	(2,735)
Other Financing Activities	22	5
Net Cash Flows from Financing Activities	76,360	118,824
Net Increase (Decrease) in Cash and Cash Equivalents	(1,363)	1,921
Cash and Cash Equivalents at Beginning of Period	2,684	763
Cash and Cash Equivalents at End of Period	$ 1,321	$ 2,684
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 60,987	$ 41,512
Net Cash Paid (Received) for Income Taxes	(3,413)	2,489
Noncash Acquisitions Under Finance Leases	503	131
Construction Expenditures Included in Current Liabilities as of December 31,	18,114	18,898

See Notes to Financial Statements beginning on page 11.

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1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 163,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

In December 2022, the UPA between AEGCo, an affiliated company, and KPCo ended upon the termination of the Rockport Plant, Unit 2 lease. The UPA allowed KPCo to purchase 30% of AEGCo's 50% capacity of Rockport Plant, Unit 2. Following the end of the lease, KPCo reached an agreement with I&M, an affiliated company, to purchase capacity from Rockport Plant, Unit 2 through May 2024 at a rate equal to PJM's RPM clearing price.

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

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

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

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

In addition, the FERC regulates the TA, which allocates shared system costs and revenues among the utility subsidiaries that are parties to each agreement. The FERC also regulates the PCA. See Note 13 - Related Party Transactions for additional information.

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 in conformity with GAAP 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 include temporary cash investments with original maturities of three months or less.

Inventory

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

Accounts Receivable and Allowance for Uncollectible Accounts

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

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

Under an affiliated receivables sales arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit. From January 2022 through August 2023, KPCo ceased selling accounts receivable to AEP Credit due to the planned sale of KPCo to Liberty. During this time period, KPCo recognized an allowance for uncollectible accounts which was calculated based on a rolling two-year average write-off proportion to gross accounts receivable. In September 2023, KPCo resumed selling accounts receivable to AEP Credit, due to the termination of the sale to Liberty. 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.

Concentrations of Credit Risk and Significant Customers

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

Significant Customer of KPCo: Marathon Petroleum Company	**2023**	**2022**
Percentage of Total Revenues	15 %	14 %
Percentage of Accounts Receivable – Customers	31 %	14 %

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. Removal costs accrued are typically recorded as regulatory liabilities when the revenue received for removal costs accrued exceeds actual removal costs incurred. The asset removal costs liability is relieved as removal costs are incurred. A regulatory asset balance will occur if actual removal costs incurred exceed accumulated removal costs accrued.

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

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

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

Allowance for Funds Used During Construction

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. KPCo records the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Asset Retirement Obligations (ARO)

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

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances from Affiliates, 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 Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is an expectation that refunds or recoveries will extend beyond a one year period, based on a company's filing with a commission or a commission directive. These deferrals are amortized when refunded or when billed to customers in later months with the KPSC's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the KPSC. On a routine basis, the KPSC reviews and/or audits KPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. Changes in fuel costs, including purchased power, are reflected in rates in a timely manner through the FAC. A portion of margins from off-system sales are given to customers through the FAC.

Revenue Recognition

Regulatory Accounting

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

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

Electricity Supply and Delivery Activities

KPCo recognizes revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes such revenues on the statements of income as the performance obligations of delivering energy to customers are satisfied. Recognized revenues include unbilled as well as-billed amounts. Wholesale transmission revenue is based on a FERC-approved formula rate filing made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under-recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. The annual true-up meets the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations". An estimated annual true-up is recorded by KPCo in the fourth quarter of each calendar year and a final annual true-up is recognized by KPCo in the second quarter of each calendar year following the filing of the annual FERC report. Any portion of the true-up applicable to an affiliated company is recorded as Accounts Receivable - Affiliated Companies or Accounts Payable - Affiliated 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 16 - Revenue from Contracts with Customers for additional information.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

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

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's 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. Realized gains and losses on cash flow hedges are recorded in Total Revenues or Purchased Electricity for Resale depending on the nature of the risk being hedged. Derivative purchases elected normal used to serve accrual based obligations are recorded in Purchased Electricity for Resale 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 Risk Management Assets or Liabilities, as appropriate, and on KPCo's statements of income in Total 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

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

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

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

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

Excise Taxes

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

Debt

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

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

Pension and OPEB Plans

KPCo participates in an AEPSC sponsored qualified pension plan and two unfunded non-qualified pension plans. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and non-qualified pension plans. KPCo also participates in OPEB plans sponsored by AEPSC to provide health and life insurance benefits for retired employees. KPCo accounts for its participation in the AEPSC sponsored pension and OPEB plans using multiple-employer accounting. See Note 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	30 %
Fixed Income	54 %
Other Investments	15 %
Cash and Cash Equivalents	1 %

OPEB Plans Assets	Target
Equity	58 %
Fixed Income	41 %
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, 2023 and 2022, the fair value of securities on loan as part of the program was $62 million and $83 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2023 and 2022.

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-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).

Earnings Per Share (EPS)

KPCo is a wholly-owned subsidiary of AEP. Therefore, KPCo is not required to report EPS.

Supplementary Income Statement Information

The following table provides the components of Depreciation and Amortization for the years ended December 31, 2023 and 2022:

Depreciation and Amortization	Years Ended December 31, 2023	2022
	(in thousands)	
Depreciation and Amortization of Property, Plant and Equipment	$ 115,984	$ 108,301
Amortization of Regulatory Assets and Liabilities	7,655	14,937
Total Depreciation and Amortization	$ 123,639	$ 123,238

Termination of Planned Disposition of KPCo and KTCo

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

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

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

Subsequent Events

Management reviewed subsequent events through February 26, 2024, the date that KPCo's 2023 annual report was available to be issued.

2. NEW ACCOUNTING STANDARDS

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

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

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

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

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

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

The amendments in the new standard may be applied on either a prospective or retrospective basis for public business entities for fiscal years beginning after December 15, 2024 with early adoption permitted. Management has not yet made a decision to early adopt the amendments to this standard or how to apply them.

3. COMPREHENSIVE INCOME

In September 2022, WPCo replaced KPCo as the operator of the Mitchell Plant. As a result of the change in operator, certain individuals employed at the Mitchell became employees of WPCo. The related pension and OPEB obligations for these employees and retirees formerly employed at Mitchell Plant, were assumed by WPCo. KPCo had a $0 balance in AOCI as of December 31, 2023 and 2022, respectively. The activity within AOCI was not material for the year ended December 31, 2022.

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.

Investigation of the Service, Rates and Facilities of KPCo

In June 2023, the KPSC issued an order directing KPCo to show cause why it should not be subject to Kentucky statutory remedies, including fines and penalties, for failure to provide adequate service in its service territory. The KPSC's show cause order did not make any determination regarding the adequacy of KPCo's service. In July 2023, KPCo filed a response to the show cause order demonstrating that it has provided adequate service. In December 2023 and February 2024, KPCo and certain intervenors filed testimony with the KPSC. In February 2024, KPCo filed a motion to strike and exclude intervenor testimony in its entirety on the grounds that issues raised are outside the scope of the proceeding and because the testimony is largely unreasoned, unsupported and provides no evidentiary value. A hearing is expected in 2024. If any fines or penalties are levied against KPCo relating to the show cause order, it could reduce net income and cash flows and impact financial condition.

2023 Kentucky Base Rate and Securitization Case

In June 2023, KPCo filed a request with the KPSC for a $93.9 million net annual increase in base rates based upon a proposed 9.9% ROE with the increase to be implemented no earlier than January 2024. The filing proposes no changes in depreciation rates and an annual level of storm restoration expense in base rates of approximately $1 million. KPCo also proposed to discontinue tracking of PJM transmission costs through a rider, and to instead collect an annual level of costs through base rates. In addition, KPCo has proposed a rider to recover certain distribution reliability investments and related incremental operation and maintenance expenses. KPCo also requested a prudency determination and recovery mechanism for approximately $15.5 million of purchased power costs not recoverable through its FAC since its last base case. KPCo's proposal did not address the disposition of its 50% interest in Mitchell Plant, which will be addressed in the future. As of December 31, 2023, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $553.1 million. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

In conjunction with its June 2023 filing, KPCo further requested to finance, through the issuance of securitization bonds, approximately $471.2 million of regulatory assets recorded as of June 2023, including: (a) $289.2 million of plant retirement costs, (b) $79.3 million of deferred storm costs related to 2020, 2021, 2022 and 2023 major storms, (c) $52.2 million of deferred purchased power expenses and (d) $50.5 million of under-recovered purchased power rider costs. Plant retirement costs and deferred purchased power expenses have been deemed prudent in prior KPSC decisions. KPCo has requested a prudency determination in this proceeding for the deferred storm costs and under-recovered purchase power rider costs since the last base case.

In November 2023, KPCo filed an uncontested settlement agreement with the KPSC, that included an annual base rate increase of $74.7 million, based upon a 9.75% ROE. Settlement parties agreed that the KPSC should approve KPCo's securitization request, and that the approximately $471.2 million regulatory assets requested for securitization are comprised of prudently incurred costs. The settlement does not modify KPCo's proposal to discontinue tracking of PJM transmission costs through a rider, and to instead collect an annual level of costs through base rates. The settlement approved KPCo's request to implement a rider to recover certain distribution reliability investments. Under the terms of the settlement, KPCo agreed to forgo recovery of approximately $15.5 million of purchased power costs not recoverable through the FAC since KPCo's last base case and excluded a return on its stand-alone NOLC deferred tax asset from the base rate revenue requirement while it seeks a private letter ruling from the IRS. Other differences between KPCo's requested annual base rate increase and the uncontested settlement agreement are primarily due to exclusion of certain employee-related expenses from the revenue requirement.

In January 2024, consistent with the November 2023 uncontested settlement agreement, the KPSC issued a financing order approving KPCo's securitization request and concluding that costs requested for recovery were prudently incurred. The KPSC's financing order includes certain additional requirements related to securitization bond structuring, marketing, placement, and issuance that were not reflected in KPCo's proposal. As a result, in January 2024, KPCo filed a request for rehearing with the KPSC to clarify certain aspects of these additional requirements. In February 2024, the KPSC denied KPCo's rehearing requests. In accordance with Kentucky statutory requirements and the financing order, the issuance of the securitized bonds is subject to final review by the KPSC after bond pricing. KPCo expects to proceed with the securitized bond issuance process and to complete the securitization process in the second half of 2024, subject to market conditions. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

In January 2024, the KPSC issued an order modifying the November 2023 uncontested settlement agreement and approving an annual base rate increase of $60 million based upon a 9.75% ROE effective with billing cycles mid-January 2024. The order reduced KPCo's base rate revenue requirement by $14.2 million to allow recovery of actual test year PJM transmission costs instead of KPCo's requested annual level of costs based on PJM 2023 projected transmission revenue requirements. The KPSC denied implementation of a rider to recover certain distribution reliability investments. The KPSC accepted KPCo's proposal to temporarily suspend collection of plant retirement costs and deferred purchased power expenses through riders, and continue to accrue carrying charges at KPCo's authorized weighted average cost of capital, pending securitization of these costs. If KPCo is unable to issue securitization bonds, recovery of plant retirement costs and deferred purchased power expenses through riders would resume. In February 2024, KPCo filed an appeal with the Commonwealth of Kentucky Franklin Circuit Court, challenging among other aspects of the order the $14.2 million base rate revenue requirement reduction.

Fuel Adjustment Clause (FAC) Review

In December 2023, KPCo received intervenor testimony in its FAC review for the two-year period ending October 31, 2022, recommending a disallowance ranging from $44.3 million to $59.8 million of its total $432.3 million purchased power cost recoveries as a result of proposed modifications to the ratemaking methodology that limits purchased power costs recoverable through the FAC. A hearing was held in February 2024. If any fuel costs are not recoverable or if refunds are ordered, it could reduce future net income and cash flows and impact financial condition.

Rockport Offset Recovery

In January 2024, KPCo filed an application with the KPSC seeking to recover an allowed cost (Rockport Offset) of $40.8 million in accordance with the terms of the settlement agreement in the 2017 Kentucky Base Rate Case permitting KPCo to use the level of non-fuel, non-environmental Rockport Plant UPA expense included in base rates to earn its authorized ROE in 2023 since the Rockport UPA ended in December 2022. An estimated Rockport Offset of $22.8 million was recovered through a rider, subject to true-up, during the 12-months ended December 2023. KPCo is requesting to recover the remaining $18 million Rockport Offset true-up over a 12-month period beginning March 2024, also through a rider. The Rockport Offset true-up is not yet reflected in revenue, as KPCo has not met the requirements of alternative revenue recognition in accordance with the accounting guidance for "Regulated Operations". In February 2024, the KPSC issued an order allowing KPCo to collect the remaining $18 million through interim rates, subject to refund, over twelve months starting in March 2024. Intervenor testimony is expected in April 2024 and an order is expected in the second quarter of 2024. If the Rockport Offset is not recoverable or refunds are ordered, it could 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:

Regulatory Assets:	December 31, 2023	December 31, 2022	Remaining Recovery Period
	(in thousands)		
Current Regulatory Assets			
Under-recovered Fuel Costs - does not earn a return	$ 10,688	$ 23,241	1 year
Total Current Regulatory Assets	$ 10,688	$ 23,241	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs (a)	$ 78,759	$ 74,430	
Other Regulatory Assets Pending Final Regulatory Approval	1,259	1,699	
Total Regulatory Assets Currently Not Earning a Return	80,018	76,129	
Total Regulatory Assets Pending Final Regulatory Approval	80,018	76,129	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs	171,214	178,502	17 years
Plant Retirement Costs - Asset Retirement Obligation Costs	110,280	110,010	17 years
Kentucky Deferred Purchased Power Expenses	43,512	52,970	4 years
Other Regulatory Assets Approved for Recovery	4,299	3,947	various
Total Regulatory Assets Currently Earning a Return	329,305	345,429	
Regulatory Assets Currently Not Earning a Return			
Fuel and Purchased Power Rider	61,376	38,164	2 years
Income Taxes, Net	21,796	—	(b)
Pension and OPEB Funded Status	24,570	23,704	12 years
Unrealized Loss on Forward Commitments	10,038	—	2 years
Other Regulatory Assets Approved for Recovery	21,122	20,759	various
Total Regulatory Assets Currently Not Earning a Return	138,902	82,627	
Total Regulatory Assets Approved for Recovery	468,207	428,056	
Total Noncurrent Regulatory Assets	$ 548,225	$ 504,185	

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

(b) Recovered over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements was $3.6 million for the year ended December 31, 2023 and is to be refunded over 5 years.

Regulatory Liabilities:	December 31, 2023	December 31, 2022	Remaining Refund Period
	(in thousands)		
Noncurrent Regulatory Liabilities			
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes, Net (a) (b)	$ —	$ (32,843)	
Total Regulatory Liabilities Currently Paying a Return	—	(32,843)	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Pending Final Regulatory Determination	—	2,098	
Total Regulatory Liabilities Currently Not Paying a Return	—	2,098	
Total Regulatory Liabilities Pending Final Regulatory Determination	—	(30,745)	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	92,871	74,393	(c)
Income Taxes, Net (a)	—	54,732	(d)
Total Regulatory Liabilities Currently Paying a Return	92,871	129,125	
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Gain on Forward Commitments	—	3,982	
Off-system Sales Margin Sharing	—	3,417	
Other Regulatory Liabilities Approved for Payment	4,756	3,074	various
Total Regulatory Liabilities Currently Not Paying a Return	4,756	10,473	
Total Regulatory Liabilities Approved for Payment	97,627	139,598	
Total Noncurrent Regulatory Liabilities	$ 97,627	$ 108,853	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Represents an income tax related regulatory asset, which is presented within net regulatory liabilities on the balance sheet.
(c) Relieved as removal costs are incurred.
(d) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements was $40.7 million for the year ended December 31, 2022.

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, 2023:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 6,009	$ 11,985	$ 12,002	$ 14,465	$ 44,461
Energy and Capacity Purchase Contracts	925	3,258	—	—	4,183
Total	$ 6,934	$ 15,243	$ 12,002	$ 14,465	$ 48,644

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

GUARANTEES

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

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2023, 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.

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, 2023, 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, 2023, management's estimates do not anticipate material clean-up costs for the identified site.

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

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

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		OPEB	
	December 31,			
Assumptions	2023	2022	2023	2022
Discount Rate	5.15 %	5.50 %	5.15 %	5.50 %
Interest Crediting Rate	4.00 %	4.25 %	NA	NA
Rate of Compensation Increase	5.15 % (a)	5.10 % (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 2023, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with an average increase of 5.15%.

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	2023	2022	2023	2022
Discount Rate	5.50 %	2.90 %	5.50 %	2.90 %
Interest Crediting Rate	4.25 %	4.00 %	NA	NA
Expected Return on Plan Assets	7.50 %	5.25 %	7.25 %	5.50 %
Rate of Compensation Increase	5.15 % (a)	4.90 % (a)	NA	NA

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

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

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

Health Care Trend Rates	December 31, 2023	2022
Initial	7.00 %	7.50 %
Ultimate	4.50 %	4.50 %
Year Ultimate Reached	2030	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, 2023, 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, 2023, the pension plans had an actuarial loss primarily due to a decrease in the discount rate, and to a lesser extent the effect of demographic experience (updated census data on January 1, 2023). These losses were partially offset by decreasing the cash balance account interest crediting rate. For the year ended December 31, 2023, the OPEB plans had an actuarial loss primarily due to discount rates, as well as actual net benefit payments above expected. These losses were partially offset by updated per capita cost assumptions. For the year ended December 31, 2022, the pension plans had an actuarial gain primarily due to an increase in the discount rate and was partially offset by increases in the assumed lump sum conversion rate and cash balance account interest crediting rate. For the year ended December 31, 2022, the OPEB plans had an actuarial gain primarily due to an increase in the discount rate and updated per capita cost assumptions. The OPEB plans gains were partially offset by a projected reduction in the Employer Group Waiver Program catastrophic reinsurance offset provided to AEP, resulting from the Inflation Reduction Act as well as an increase in the health care cost trend assumption. The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		OPEB	
	2023	2022	2023	2022
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1,	$ 86,855	$ 184,199	$ 23,605	$ 36,932
Service Cost	1,474	2,739	63	172
Interest Cost	4,814	4,480	1,269	953
Actuarial (Gain) Loss	5,833	(36,034)	1,335	(3,106)
Transfers	—	(57,450)	—	(7,548)
Benefit Payments	(6,802)	(11,079)	(4,619)	(5,520)
Participant Contributions	—	—	1,470	1,713
Medicare Subsidy	—	—	6	9
Benefit Obligation as of December 31,	$ 92,174	$ 86,855	$ 23,129	$ 23,605
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 83,062	$ 203,932	$ 44,136	$ 77,433
Actual Gain (Loss) on Plan Assets	11,161	(31,289)	6,884	(13,714)
Transfers	—	(78,502)	—	—
Company Contributions	—	—	1	(15,776)
Participant Contributions	—	—	1,470	1,713
Benefit Payments	(6,802)	(11,079)	(4,619)	(5,520)
Fair Value of Plan Assets as of December 31,	$ 87,421	$ 83,062	$ 47,872	$ 44,136
Funded (Underfunded) Status as of December 31,	$ (4,753)	$ (3,793)	$ 24,743	$ 20,531

Amounts Recognized on the Balance Sheets

	Pension Plans		OPEB	
	December 31,			
	2023	2022	2023	2022
	(in thousands)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ —	$ —	$ 24,743	$ 20,531
Other Current Liabilities – Accrued Short-term Benefit Liability	(21)	(4)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(4,732)	(3,789)	—	—
Funded (Underfunded) Status	$ (4,753)	$ (3,793)	$ 24,743	$ 20,531

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

The following tables show the components of the plans included in Regulatory Assets and the items attributable to the change in these components:

	Pension Plans		OPEB	
	December 31,			
	2023	2022	2023	2022
Components	(in thousands)			
Net Actuarial Loss	$ 18,788	$ 16,985	$ 6,561	$ 9,355
Prior Service Credit	—	—	(780)	(2,637)
Recorded as				
Regulatory Assets	$ 18,789	$ 16,986	$ 5,781	$ 6,718
Deferred Income Taxes	(1)	(1)	—	—

	Pension Plans		OPEB	
	2023	2022	2023	2022
Components	(in thousands)			
Actuarial (Gain) Loss During the Year	$ 1,803	$ 3,370	$ (2,348)	$ 14,492
Amortization of Actuarial Loss	—	(1,867)	(445)	—
Amortization of Prior Service Credit	—	—	1,856	2,375
Transfers - Prior Service Cost	—	—	1	975
Transfers - (Gain)/loss	—	(7,148)	(1)	1,485
Change for the Year Ended December 31,	$ 1,803	$ (5,645)	$ (937)	$ 19,327

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,			
2023	2022	2023	2022
2.1 %	2.0 %	2.9 %	2.8 %

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 411.3	$ —	$ —	$ —	$ 411.3	10.0 %
International	389.8	—	—	—	389.8	9.5 %
Common Collective Trusts (b)	—	—	—	420.9	420.9	10.2 %
Subtotal – Equities	801.1	—	—	420.9	1,222.0	29.7 %
Fixed Income (a):						
United States Government and Agency Securities	8.3	1,099.2	—	—	1,107.5	26.9 %
Corporate Debt	—	894.8	—	—	894.8	21.7 %
Foreign Debt	—	167.1	—	—	167.1	4.1 %
State and Local Government	—	38.7	—	—	38.7	0.9 %
Other – Asset Backed	—	1.3	—	—	1.3	— %
Subtotal – Fixed Income	8.3	2,201.1	—	—	2,209.4	53.6 %
Infrastructure (b)	—	—	—	101.4	101.4	2.5 %
Real Estate (b)	—	—	—	239.3	239.3	5.8 %
Alternative Investments (b)	—	—	—	241.8	241.8	5.8 %
Cash and Cash Equivalents (b)	—	51.0	—	33.8	84.8	2.1 %
Other – Pending Transactions and Accrued Income (c)	—	—	0.1	19.4	19.5	0.5 %
Total	$ 809.4	$ 2,252.1	$ 0.1	$ 1,056.6	$ 4,118.2	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 540.6	$ —	$ —	$ —	$ 540.6	32.3 %
International	288.4	—	—	—	288.4	17.2 %
Common Collective Trusts (a)	—	—	—	131.6	131.6	7.9 %
Subtotal – Equities	829.0	—	—	131.6	960.6	57.4 %
Fixed Income:						
Common Collective Trust Debt (a)	—	—	—	146.7	146.7	8.8 %
United States Government and Agency Securities	1.4	163.3	—	—	164.7	9.8 %
Corporate Debt	—	149.0	—	—	149.0	8.9 %
Foreign Debt	—	28.6	—	—	28.6	1.7 %
State and Local Government	41.5	7.8	—	—	49.3	3.0 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.9	348.9	—	146.7	538.5	32.2 %
Trust Owned Life Insurance:						
International Equities	—	22.3	—	—	22.3	1.3 %
United States Bonds	—	130.0	—	—	130.0	7.8 %
Subtotal – Trust Owned Life Insurance	—	152.3	—	—	152.3	9.1 %
Cash and Cash Equivalents (a)	25.9	—	—	2.9	28.8	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(6.9)	(6.9)	(0.4)%
Total	$ 897.8	$ 501.2	$ —	$ 274.3	$ 1,673.3	100.0 %

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

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2022:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 347.6	$ —	$ —	$ —	$ 347.6	8.4 %
International	398.4	—	—	—	398.4	9.7 %
Common Collective Trusts (b)	—	—	—	379.9	379.9	9.2 %
Subtotal – Equities	746.0	—	—	379.9	1,125.9	27.3 %
Fixed Income (a):						
United States Government and Agency Securities	(0.6)	1,071.4	—	—	1,070.8	26.0 %
Corporate Debt	—	891.7	—	—	891.7	21.6 %
Foreign Debt	—	140.2	—	—	140.2	3.4 %
State and Local Government	—	37.0	—	—	37.0	0.9 %
Other – Asset Backed	—	0.8	—	—	0.8	— %
Subtotal – Fixed Income	(0.6)	2,141.1	—	—	2,140.5	51.9 %
Infrastructure (b)	—	—	—	109.2	109.2	2.6 %
Real Estate (b)	—	—	—	276.9	276.9	6.7 %
Alternative Investments (b)	—	—	—	319.7	319.7	7.8 %
Cash and Cash Equivalents (b)	—	64.9	—	58.3	123.2	3.0 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	29.3	29.3	0.7 %
Total	$ 745.4	$ 2,206.0	$ —	$ 1,173.3	$ 4,124.7	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2022:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 414.1	$ —	$ —	$ —	$ 414.1	26.7 %
International	265.0	—	—	—	265.0	17.1 %
Common Collective Trusts (a)	—	—	—	169.1	169.1	10.9 %
Subtotal – Equities	679.1	—	—	169.1	848.2	54.7 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	120.3	120.3	7.8 %
United States Government and Agency Securities	0.1	155.8	—	—	155.9	10.1 %
Corporate Debt	—	141.5	—	—	141.5	9.1 %
Foreign Debt	—	21.0	—	—	21.0	1.4 %
State and Local Government	62.9	7.8	—	—	70.7	4.6 %
Subtotal – Fixed Income	63.0	326.1	—	120.3	509.4	33.0 %
Trust Owned Life Insurance:						
International Equities	—	46.7	—	—	46.7	3.0 %
United States Bonds	—	110.3	—	—	110.3	7.1 %
Subtotal – Trust Owned Life Insurance	—	157.0	—	—	157.0	10.1 %
Cash and Cash Equivalents (a)	23.2	—	—	6.7	29.9	1.9 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	4.8	4.8	0.3 %
Total	$ 765.3	$ 483.1	$ —	$ 300.9	$ 1,549.3	100.0 %

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

Accumulated Benefit Obligation

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

	December 31, 2023	2022
	(in thousands)	
Qualified Pension Plan	$ 89,419	$ 84,724
Nonqualified Pension Plan	7	49
Total Accumulated Benefit Obligation	$ 89,426	$ 84,773

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,	
	2023	2022
	(in thousands)	
Projected Benefit Obligation	$ 92,174	$ 86,855
Fair Value of Plan Assets	87,421	83,062
Underfunded Projected Benefit Obligation	$ (4,753)	$ (3,793)

Accumulated Benefit Obligation

	Underfunded Pension Plans	
	December 31,	
	2023	2022
	(in thousands)	
Accumulated Benefit Obligation	$ 89,426	$ 84,773
Fair Value of Plan Assets	87,421	83,062
Underfunded Accumulated Benefit Obligation	$ (2,005)	$ (1,711)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the Pension and OPEB plans of $11 thousand and $54 thousand, respectively, during 2024. 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)	
2024	$ 8,165	$ 3,670
2025	7,943	3,743
2026	7,672	3,661
2027	7,812	3,516
2028	7,775	3,406
Years 2029 to 2033, in Total	36,460	15,398

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,			
	2023	2022	2023	2022
	(in thousands)			
Service Cost	$ 1,474	$ 2,739	$ 63	$ 172
Interest Cost	4,814	4,480	1,269	953
Expected Return on Plan Assets	(7,131)	(8,116)	(3,201)	(3,885)
Amortization of Prior Service Credit	—	—	(1,856)	(2,375)
Amortization of Net Actuarial Loss	—	1,867	445	—
Net Periodic Benefit Cost (Credit)	(843)	970	(3,280)	(5,135)
Capitalized Portion	(812)	(1,287)	(35)	(81)
Net Periodic Benefit Credit Recognized in Expense	$ (1,655)	$ (317)	$ (3,315)	$ (5,216)

American Electric Power System Retirement Savings Plan

KPCo participates in an AEPSC sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions totaled $1.4 million in 2023 and $2 million in 2022.

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, 2023	December 31, 2022	Unit of Measure
	(in thousands)		
Commodity:			
Power	3,303	3,450	MWhs
Natural Gas	9,761	—	MMBtus
Heating Oil and Gasoline	253	—	Gallons

Cash Flow Hedging Strategies

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

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

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON KPCo's FINANCIAL STATEMENTS

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

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third-party contractual agreements and risk profiles. KPCo netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $1.2 million and $14 thousand as of December 31, 2023 and 2022, respectively. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets as of December 31, 2023 and 2022.

The following tables represent the gross fair value of KPCo's derivative activity on the balance sheets. Unless shown as a separate line on the balance sheets due to materiality, Current Risk Management Assets are included in Prepayments and Other Current Assets, Long-term Risk Management Assets are included in Deferred Charges and Other Noncurrent Assets, Current Risk Management Liabilities are included in Other Current Liabilities and Long-term Risk Management Liabilities are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

	December 31, 2023		
Balance Sheet Location	**Risk Management Contracts – Commodity (a)**	**Gross Amounts Offset on the Balance Sheets (b)**	**Net Amounts of Presented (c)**
		(in thousands)	
Current Risk Management Assets	$ 3,360	$ (296)	$ 3,064
Long-term Risk Management Assets	230	(215)	15
Total Assets	3,590	(511)	3,079
Current Risk Management Liabilities	9,375	(1,449)	7,926
Long-term Risk Management Liabilities	1,189	(215)	974
Total Liabilities	10,564	(1,664)	8,900
Total MTM Derivative Contract Net Assets (Liabilities)	$ (6,974)	$ 1,153	$ (5,821)

Balance Sheet Location	December 31, 2022 Risk Management Contracts – Commodity (a)	Gross Amounts Offset on the Balance Sheets (b)	Net Amounts of Presented (c)
		(in thousands)	
Current Risk Management Assets	$ 8,607	$ (144)	$ 8,463
Long-term Risk Management Assets	137	(137)	—
Total Assets	8,744	(281)	8,463
Current Risk Management Liabilities	144	(144)	—
Long-term Risk Management Liabilities	137	(137)	—
Total Liabilities	281	(281)	—
Total MTM Derivative Contract Net Assets	$ 8,463	$ —	$ 8,463

(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 on the balance sheets.

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

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2023	2022
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 1	$ 8
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	77	228
Other Operation	—	148
Maintenance	—	263
Regulatory Assets (a)	(10,043)	(25)
Regulatory Liabilities (a)	1,209	16,998
Total Gain (Loss) on Risk Management Contracts	$ (8,756)	$ 17,620

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

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 (Loss) 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 Total Revenues or Purchased Electricity, Fuel and Other Consumables Used for Electric Generation on KPCo's statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2023 and 2022, 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 (Loss) on its balance sheets into Interest Expense on its statements of income in those periods in which hedged interest payments occur. During the years ended 2023 and 2022, 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 (Loss) on KPCo's balance sheets as of December 31, 2023 and 2022.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ due to market price changes. As of December 31, 2023, 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, 2023 and 2022, KPCo did not have derivative contracts with collateral triggering events in a net liability position.

Cross-Acceleration Triggers

Certain interest rate derivative contracts contain cross-acceleration provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-acceleration provisions could be triggered if there was a non-performance event by KPCo under any of their outstanding debt of at least $50 million and the lender on that debt has accelerated the entire repayment obligation. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-acceleration provisions in contracts. KPCo had no derivative contracts with cross-acceleration provisions in a net liability position and no cash collateral posted as of December 31, 2023 and 2022. If a cross-acceleration provision would have been triggered, settlement at fair value would have been required.

Cross-Default Triggers

In addition, a majority of KPCo's non-exchange-traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third-party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. KPCo had derivative contracts with cross-default provisions in a net liability position of $8 million and $0, and no cash collateral posted as of December 31, 2023 and 2022, respectively. If a cross-default provision would have been triggered, settlement at fair value would have been required.

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,			
	2023		2022	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 1,299,806	$ 1,302,987	$ 1,178,448	$ 1,148,769

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, 2023

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2022

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 137	$ 8,607	$ (281)	$ 8,463
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 137	$ 144	$ (281)	$ —

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

Year Ended December 31, 2022	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2021	$ 5,871
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	2,801
Settlements	(8,672)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	8,463
Balance as of December 31, 2022	$ 8,463

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

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of December 31, 2023 and 2022:

Significant Unobservable Inputs
December 31, 2023

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

Significant Unobservable Inputs
December 31, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted (b)
	(in thousands)						
FTRs	$ 8,607	$ 144	Flow	Price	$ (3.10)	$ 18.79	$ 2.48

(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, 2023 and 2022:

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, 2023	2022
	(in thousands)	
Federal:		
Current	$ (2,404)	$ 74
Deferred	(24,769)	(30,347)
Total Federal	(27,173)	(30,273)
State and Local:		
Current	788	691
Deferred	(1,290)	(1,446)
Total State and Local	(502)	(755)
Income Tax Benefit	$ (27,675)	$ (31,028)

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, 2023	2022
	(in thousands)	
Net Income	$ 33,962	$ 47,552
Income Tax Benefit	(27,675)	(31,028)
Pretax Income	$ 6,287	$ 16,524
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 1,320	$ 3,470
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Reversal of Origination Flow-Through	972	1,475
State and Local Income Taxes, Net	(397)	(594)
Removal Costs	(2,587)	(2,660)
Tax Reform Excess ADIT Reversal (a)	(25,944)	(32,452)
Other	(1,039)	(267)
Income Tax Benefit	$ (27,675)	$ (31,028)
Effective Income Tax Rate	(440.2)%	(187.8)%

(a) In January 2021, as part of the 2020 Kentucky Base Rate Case, the KPSC issued an order that shortened the previously authorized refund period for Excess ADIT that is not subject to normalization requirements from 18 years to 3 years.

Net Deferred Tax Liability

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

	December 31, 2023	December 31, 2022
	(in thousands)	
Deferred Tax Assets	$ 74,967	$ 86,163
Deferred Tax Liabilities	(548,810)	(542,380)
Net Deferred Tax Liabilities	$ (473,843)	$ (456,217)
Property Related Temporary Differences	$ (307,659)	$ (304,463)
Amounts Due to Customers for Future Income Taxes	30,890	39,613
Deferred State Income Taxes	(99,720)	(96,837)
Regulatory Assets	(111,007)	(109,919)
Net Operating Loss Carryforward	12,344	11,671
All Other, Net	1,309	3,718
Net Deferred Tax Liabilities	$ (473,843)	$ (456,217)

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. KPCo and other AEP subsidiaries have agreed to extend the statute of limitations on the 2017-2019 tax returns to October 31, 2024, to allow time for our refund claim to be approved by the Congressional Joint Committee on Taxation. The statute of limitations for the 2020 return is set to naturally expire in October 2024 as well.

The current IRS audit and associated refund claim evolved from a net operating loss carryback to 2015 that originated in the 2017 return. KPCo and other AEP subsidiaries have received and agreed to immaterial IRS proposed adjustments on the 2017 tax return. The IRS exam is complete, and KPCo and other AEP subsidiaries are currently waiting on the IRS to submit the refund claim to the Congressional Joint Committee on Taxation for resolution and final approval.

Net Income Tax Operating Loss Carryforward

KPCo has state net income tax operating loss carryforwards of $196 million in 2023. As a result, KPCo recognized deferred state income tax benefits in 2023 of $10 million. This is consistent with the net operating loss carryforwards and deferred state income tax benefits recognized in 2022. Management anticipates future taxable income will be sufficient to realize the state net income tax operating loss tax benefits before the state carryforward begins expiring in 2035.

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 lease rentals and finance lease amortization costs are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Interest on finance lease liabilities is generally charged to Interest Expense. Lease costs associated with capital projects are included in Property, Plant and Equipment 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, 2023	2022
	(in thousands)	
Operating Lease Cost	$ 71	$ 14,058
Finance Lease Cost:		
Amortization of Finance Leases	83	2,735
Interest on Finance Leases	22	63
Total Lease Rental Costs (a)	$ 176	$ 16,856

(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,			
	2023	2022	2023	2022
Operating Leases	5.10	5.92	3.49 %	2.95 %
Finance Leases	7.34	4.73	6.13 %	4.41 %

	Years Ended December 31, 2023	2022
	(in thousands)	
Cash Paid for Amounts Included in the Measurement of Lease Liabilities		
Operating Cash Flows Used for Operating Leases	$ 71	$ 14,050
Operating Cash Flows Used for Finance Leases	22	63
Financing Cash Flows Used for Finance Leases	83	2,735
Non-cash Acquisitions Under Operating Leases	$ 639	$ 422

The following tables show the property, plant and equipment under finance leases and noncurrent assets under operating leases and related obligations recorded on KPCo's balance sheets. Unless shown as a separate line on the balance sheets due to materiality, net operating lease assets are included in Deferred Charges and Other Noncurrent Assets, current finance lease obligations are included in Other Current Liabilities and long-term finance lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets. Lease obligations are not recognized on the balance sheets for lease agreements with a lease term of less than twelve months.

	December 31, 2023	December 31, 2022
	(in thousands)	
Property, Plant and Equipment Under Finance Leases		
Generation	$ 386	$ 465
Other Property, Plant and Equipment	695	209
Total Property, Plant and Equipment Under Finance Leases	1,081	674
Accumulated Amortization	292	305
Net Property, Plant and Equipment Under Finance Leases	$ 789	$ 369
Obligations Under Finance Leases		
Noncurrent Liability	$ 677	$ 288
Liability Due Within One Year	112	81
Total Obligations Under Finance Leases	$ 789	$ 369

	December 31, 2023	December 31, 2022
	(in thousands)	
Operating Lease Assets	$ 1,108	$ 528
Obligations Under Operating Leases		
Noncurrent Liability	$ 963	$ 450
Liability Due Within One Year	195	128
Total Obligations Under Operating Leases	$ 1,158	$ 578

Future minimum lease payments consisted of the following as of December 31, 2023:

Future Minimum Lease Payments	Finance Leases	Operating Leases
	(in thousands)	
2024	$ 159	$ 273
2025	156	241
2026	142	227
2027	125	209
2028	85	197
After 2028	350	218
Total Future Minimum Lease Payments	1,017	1,365
Less: Imputed Interest	228	207
Estimated Present Value of Future Minimum Lease Payments	$ 789	$ 1,158

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, 2023, the maximum potential loss for these lease agreements was $76 thousand assuming the fair value of the equipment is zero at the end of the lease term.

Lessor Activity

KPCo's lessor activity was immaterial as of and for the twelve months ended December 31, 2023 and December 31, 2022, respectively.

12. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding:

Type of Debt	Maturity	Average of 2023	of December 31, 2023	2022	Outstanding as of December 31, 2023	2022
					(in thousands)	
Senior Unsecured Notes	2024-2047	5.41%	%	%	$1,060,225	$ 688,626
Pollution Control Bonds	2026 (a)	4.70%	4.70%	2.35%	64,588	64,896
Notes Payable - Affiliated	2028	5.29%	5.29%	—%	25,000	—
Other Long-term Debt	2024	6.41%	6.41%	%	149,993	424,926
Outstanding					$1,299,806	$1,178,448

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

As of December 31, 2023, outstanding long-term debt was payable as follows:

	2024	2025	2026	2027	2028	After 2028	Total
				(in thousands)			
Principal Amount	$ 215,000	$ —	$ 265,000	$ 40,000	$ 25,000	$ 760,000	$1,305,000
Debt Issuance Costs							(5,194)
Outstanding							$1,299,806

Dividend Restrictions

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

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

KPCo has credit agreements that contain a covenant that limit its debt to capitalization ratio to 67.5%. As of December 31, 2023, 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, 2023, 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 $649.8 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, 2023, the amount of any such restrictions was $72.5 million.

Corporate Borrowing Program – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2023 and 2022 are included in Advances from Affiliates 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)			
2023	$ 169,398	$ 243,803	$ 112,116	$ 243,764	$ 49,567	$ 250,000
2022	161,643	28,393	82,006	23,343	94,428	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
2023	5.81 %	4.66 %	5.72 %	5.72 %	5.53 %	5.72 %
2022	5.28 %	0.10 %	2.15 %	2.15 %	2.23 %	2.15 %

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

	Years Ended December 31,	
	2023	2022
	(in thousands)	
Interest Expense	$ 6,399	$ 1,985
Interest Income	116	102

Securitized Accounts Receivables – AEP Credit

Under an affiliated receivables sales arrangement, KPCo sold, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit. In January 2022, due to the expected sale to Liberty, KPCo ceased selling accounts receivable to AEP Credit. As a result, in the first quarter of 2022, KPCo began recording an allowance for uncollectible accounts on its balance sheet for those receivables no longer sold to AEP Credit. In September 2023, KPCo resumed selling accounts receivable to AEP Credit, due to the termination of the sale to Liberty, and the balance in KPCo's allowance for uncollectible accounts was reversed. KPCo is charged a fee for each sale that is based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience from previous purchases of KPCo's customer accounts receivable. No allowance for 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 Operation expense on KPCo's statements of income. KPCo manages and services its accounts receivables sold.

AEP Credit's receivables securitization agreement provides a commitment of $900 million from bank conduits to purchase receivables. The agreement was amended in August 2023 to increase the commitment from $750 million and expires in September 2025. As of December 31, 2023, KPCo was in compliance with all requirements under the agreement.

KPCo's amounts of accounts receivable and accrued unbilled revenues under the sale of receivables agreement were $42.7 million and $0 as of December 31, 2023 and 2022, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $1.9 million and $63 thousand for the years ended December 31, 2023 and 2022, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $205.3 million and $66 million for the years ended December 31, 2023 and 2022, respectively.

13. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Income Taxes" section of Note 1 in addition to "Corporate Borrowing Program – AEP System" and "Securitized Accounts Receivables – AEP Credit" sections of Note 12.

Intercompany Billings

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

Power Coordination Agreement

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

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

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 $177 thousand and $1 million for the years ended December 31, 2023 and 2022, respectively.

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. Upon transfer of the Mitchell Plant to WPCo in August 2022, this agreement was terminated with KPCo. Through the first eight months of 2022, KPCo recorded $2 million for urea transloading provided by I&M. These expenses were recorded as Purchased Electricity, Fuel and Other Consumables Used for Electric Generation on KPCo's statements of income.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions and the net book value of all sales and purchases for the years ended December 31, 2023 and 2022 were not material. These sales and purchases are recorded in Property, Plant and Equipment on the balance sheets.

Unit Power Agreements

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

In April 2021, AEGCo and I&M executed an agreement to purchase 100% of the interests in Rockport Plant, Unit 2 effective at the end of the lease term on December 7, 2022. Beginning December 8, 2022, AEGCo and I&M applied the joint plant accounting model to their respective 50% undivided interests in the jointly owned Rockport Plant, Unit 2 as well as any future investments made prior to the current estimated retirement date of December 2028.

Prior to the termination of the lease, I&M assigned 30% of the power to KPCo as part of a UPA between AEGCo and KPCo. Beginning December 8, 2022, AEGCo billed 100% of its share of the Rockport Plant to I&M and ceased billing to KPCo. KPCo reached an agreement with I&M, from the end of the lease through May 2024, to buy capacity from Rockport Plant, Unit 2 through the PCA at a rate equal to PJM's RPM clearing price. KPCo's direct purchases from AEGCo were $2 million and $93.1 million for the years ended December 31, 2023 and 2022, respectively. These direct purchases are presented as Purchased Electricity from AEP Affiliates on the statements of income.

PJM Transmission Service Charges

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

KPCo's net charges recorded as a result of the TA for the years ended December 31, 2023 and 2022 were $66 million and $64.9 million, respectively, and were recorded in Other Operation expenses on KPCo's statements of income.

Charitable Contributions to AEP Foundation

The American Electric Power Foundation is funded by American Electric Power and its utility operating units. The Foundation provides a permanent, ongoing resource for charitable initiatives and multi-year commitments in the communities served by AEP and initiatives outside of AEP's 11-state service area. In 2022, KPCo made a $2.8 million charitable contribution to the AEP Foundation recorded in Other Operation on the statements of income. In 2023, there were no charitable contributions made to the AEP Foundation

Affiliated Revenues

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

Related Party Revenues	Years Ended December 31, 2023	2022
	(in thousands)	
Transmission Agreement Sales	$ 10,038	$ 17,701
Other Revenues	1,135	1,550
Total Affiliated Revenues	$ 11,173	$ 19,251

The above summarized related party revenues are shown in Sales to AEP Affiliates on KPCo's statements of income.

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14. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a variable interest in a VIE. A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers whether KPCo has the power to direct the most significant activities of the VIE and is obligated to absorb losses or receive the expected residual returns that are significant to the VIE. Management believes that significant assumptions and judgments were applied consistently. KPCo is not the primary beneficiary of any VIE and has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. Parent is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct-charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the years ended December 31, 2023 and 2022 were $46.8 million and $69.7 million, respectively. The carrying amount of liabilities associated with AEPSC as of December 31, 2023 and 2022 were $3.3 million and $6.1 million , respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of Parent, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant. In December 2022, the UPA between AEGCo and KPCo ended upon the termination of the Rockport Plant, Unit 2 lease. As a result, AEGCo began selling all of the output from the Rockport Plant to I&M, eliminating KPCo's significant variable interest in AEGCo as of December 31, 2022. KPCo was previously exposed to losses to the extent it could not recover the costs of AEGCo through its normal business operations. Total billings from AEGCo for the years ended December 31, 2023 and 2022 were $307 thousand and $92.9 million, respectively. The carrying amount of liabilities associated with AEGCo as of December 31, 2023 and 2022 were $0 and $2 million, respectively.

15. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment is shown functionally on the face of KPCo's balance sheets. The following table includes KPCo's total plant balances as of December 31, 2023 and 2022:

	December 31, 2023	2022
	(in thousands)	
Regulated Property, Plant and Equipment		
Generation	$ 1,239,925	$ 1,236,474
Transmission	838,264	801,838
Distribution	1,119,303	1,061,601
Other	173,804	166,754
CWIP	159,612	137,964
Less: Accumulated Depreciation	1,205,743	1,155,997
Total Regulated Property, Plant and Equipment - Net	2,325,165	2,248,634
Nonregulated Property, Plant and Equipment - Net	997	1,003
Total Property, Plant and Equipment - Net	$ 2,326,162	$ 2,249,637

Depreciation

KPCo provides for depreciation of Property, Plant and Equipment 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 2023 and 2022.

	2023		2022	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	3.3%	69 - 73	3.0%	69 - 73
Transmission	2.7%	37 - 75	2.7%	37 - 75
Distribution	3.4%	11 - 75	3.4%	11 - 75
Other	8.6%	5 - 75	8.2%	5 - 75

The composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization on the balance sheets. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability.

Asset Retirement Obligations (ARO)

The following is a reconciliation of the 2023 and 2022 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)			
2023	$ 18,477	$ 811	$ —	$ (1,088)	$ 76	$ 18,276
2022	17,697	803	—	(1,162)	1,139	18,477

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

Allowance for Funds Used During Construction

KPCo's amounts of allowance for equity and borrowed funds used during construction are summarized in the following table:

	Years Ended December 31, 2023	2022
	(in thousands)	
Allowance for Equity Funds Used During Construction	$ 968	$ 1,192
Allowance for Borrowed Funds Used During Construction	4,838	1,635

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 Property, Plant and Equipment 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, 2023					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,055,915	$ 21,596	$ 534,308
KPCo's Share as of December 31, 2022					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,052,996	$ 23,231	$ 518,178

(a) Operated by WPCo.

16. 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,	
	2023	**2022**
	(in thousands)	
Retail Revenues:		
Residential Revenues	$ 246,124	$ 317,814
Commercial Revenues	159,443	197,505
Industrial Revenues	149,336	185,174
Other Retail Revenues	1,979	2,193
Total Retail Revenues	556,882	702,686
Wholesale Revenues:		
Generation Revenues	12,686	29,680
Transmission Revenues (a)	28,799	35,522
Total Wholesale Revenues	41,485	65,202
Other Revenues from Contracts with Customers (b)	11,428	11,541
Total Revenues from Contracts with Customers	609,795	779,429
Other Revenues:		
Alternative Revenue Programs (c)	5,052	(6,216)
Other Revenues	2	8
Total Other Revenues	5,054	(6,208)
Total Revenues	$ 614,849	$ 773,221

(a) Amounts included affiliated and nonaffiliated revenues. The affiliated revenues were $17 million and $19 million for years ended December 31, 2023 and 2022, respectively.
(b) Amounts included affiliated and nonaffiliated revenues.
(c) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

Performance Obligations

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

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

Retail Revenues

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

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

Wholesale Revenues - Generation

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

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

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

Wholesale Revenues - Transmission

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

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

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

Fixed Performance Obligations

The following table represents KPCo's remaining fixed performance obligations satisfied over time as of December 31, 2023. Fixed performance obligations primarily include electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. KPCo elected to apply the exemption to not disclose the value of unsatisfied performance obligations for contracts with an original expected term of one year or less. Due to the annual establishment of revenue requirements, transmission revenues are excluded from the table below. The amounts shown in the table below include affiliated and nonaffiliated revenues.

2024	2025-2026	2027-2028	After 2028	Total
		(in thousands)		
$ 1,435	$ 2,870	$ 2,870	$ 1,435	$ 8,610

Contract Assets and Liabilities

Contract assets are recognized when KPCo has a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. KPCo did not have material contract assets as of December 31, 2023 and 2022, 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, 2023 and 2022, respectively.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on KPCo's balance sheets within the Accounts Receivable - Customers line item. KPCo's balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of December 31, 2023 and 2022, 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 - Affiliated Companies on KPCo's balance sheets were $12.2 million and $9.1 million, respectively, as of December 31, 2023 and December 31, 2022.

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 and noncurrent assets 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 Other Operation on KPCo's statements of income. KPCo did not have material contract costs as of December 31, 2023 and 2022, respectively.

Kentucky Power Company

2024 Annual Report

Audited Financial Statements

KENTUCKY POWER℠

An AEP Company

BOUNDLESS ENERGY℠

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GLOSSARY OF TERMS

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 consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated VIE of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KGPCo, KPCo, OPCo and WPCo.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AFUDC	Allowance for Equity Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ASU	Accounting Standards Update.
CCR	Coal Combustion Residual.
CWIP	Construction Work in Progress.
ELG	Effluent Limitation Guidelines.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE of AEP.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
KTCo	AEP Kentucky Transmission Company, Inc., a wholly-owned AEPTCo transmission subsidiary.
Liberty	Liberty Utilities Co., a subsidiary of Algonquin Power & Utilities Corporation.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NOL	Net operating losses.
NOLC	Net operating loss carryforwards.
NO_x	Nitrogen oxide.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third-party sales. AEPSC acts as the agent.
OTC	Over-the-counter.

Term	Meaning
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, jointly-owned by AEGCo and I&M, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TA	Transmission Agreement, effective November 2010, among APCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	West Virginia Public Service Commission.

Report of Independent Auditors

To the Management and Board of Directors of Kentucky Power Company

Opinion

We have audited the accompanying financial statements of Kentucky Power Company (the "Company"), which comprise the balance sheets as of December 31, 2024 and 2023, and the related statements of income, of changes in common shareholder's equity and of cash flows for the years then ended, including the related notes (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date the financial statements are available to be issued.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures

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include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

PricewaterhouseCoopers LLP

Columbus, Ohio
February 13, 2025

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2024 and 2023
(in thousands)

	Years Ended December 31, 2024	2023
REVENUES		
Electric Generation, Transmission and Distribution	$ 680,307	$ 602,847
Sales to AEP Affiliates	14,512	11,173
Other Revenues	966	829
TOTAL REVENUES	695,785	614,849
EXPENSES		
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	234,929	226,287
Purchased Electricity from AEP Affiliates	373	1,968
Other Operation	158,846	106,883
Maintenance	63,662	64,173
Depreciation and Amortization	116,091	123,639
Taxes Other Than Income Taxes	26,440	27,545
TOTAL EXPENSES	600,341	550,495
OPERATING INCOME	95,444	64,354
Other Income (Expense):		
Interest Income	1,003	202
Allowance for Equity Funds Used During Construction	2,034	968
Non-Service Cost Components of Net Periodic Benefit Cost	5,098	7,576
Interest Expense	(63,736)	(66,813)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	39,843	6,287
Income Tax Expense (Benefit)	2,981	(27,675)
NET INCOME	$ 36,862	$ 33,962

The common stock of KPCo is wholly-owned by Parent.

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2024 and 2023
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2022	$ 50,450	$ 526,287	$ 343,573	$ 920,310
Capital Contribution from Parent		868		868
Return of Capital to Parent		(384)		(384)
Net Income			33,962	33,962
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2023	50,450	526,771	377,535	954,756
Capital Contribution from Parent		831		831
Return of Capital to Parent		(1,533)		(1,533)
Net Income			36,862	36,862
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2024	$ 50,450	$ 526,069	$ 414,397	$ 990,916

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2024 and 2023
(in thousands)

	December 31, 2024	December 31, 2023
CURRENT ASSETS		
Cash and Cash Equivalents	$ 839	$ 1,321
Accounts Receivable:		
Customers	18,369	17,723
Affiliated Companies	19,144	24,213
Accrued Unbilled Revenues	9,719	—
Miscellaneous	163	117
Total Accounts Receivable	47,395	42,053
Fuel	59,490	80,638
Materials and Supplies	24,140	25,445
Risk Management Assets	5,255	3,064
Regulatory Asset for Under-Recovered Fuel Costs	8,635	10,688
Margin Deposits	4,173	2,926
Prepayments and Other Current Assets	2,424	15,027
TOTAL CURRENT ASSETS	152,351	181,162
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,290,637	1,239,925
Transmission	950,887	838,264
Distribution	1,194,543	1,119,303
Other Property, Plant and Equipment	175,096	175,031
Construction Work in Progress	115,772	159,612
Total Property, Plant and Equipment	3,726,935	3,532,135
Accumulated Depreciation and Amortization	1,254,903	1,205,973
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	2,472,032	2,326,162
OTHER NONCURRENT ASSETS		
Regulatory Assets	608,213	548,225
Deferred Charges and Other Noncurrent Assets	83,660	78,479
TOTAL OTHER NONCURRENT ASSETS	691,873	626,704
TOTAL ASSETS	$ 3,316,256	$ 3,134,028

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2024 and 2023
(dollars in thousands)

	December 31, 2024	December 31, 2023
CURRENT LIABILITIES		
Advances from Affiliates	$ 183,212	$ 49,567
Accounts Payable:		
General	60,684	36,823
Affiliated Companies	49,421	46,018
Long-term Debt Due Within One Year – Nonaffiliated	150,000	215,000
Risk Management Liabilities	454	7,926
Customer Deposits	38,265	38,027
Accrued Taxes	43,532	49,490
Obligations Under Operating Leases	216	195
Other Current Liabilities	30,032	44,610
TOTAL CURRENT LIABILITIES	555,816	487,656
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	1,060,473	1,059,806
Long-term Debt – Affiliated	—	25,000
Deferred Income Taxes	484,017	473,843
Regulatory Liabilities	118,345	97,627
Asset Retirement Obligations	85,213	18,071
Employee Benefits and Pension Obligations	9,011	9,581
Obligations Under Operating Leases	1,795	963
Deferred Credits and Other Noncurrent Liabilities	10,670	6,725
TOTAL NONCURRENT LIABILITIES	1,769,524	1,691,616
TOTAL LIABILITIES	2,325,340	2,179,272
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	526,069	526,771
Retained Earnings	414,397	377,535
TOTAL COMMON SHAREHOLDER'S EQUITY	990,916	954,756
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 3,316,256	$ 3,134,028

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2024 and 2023
(in thousands)

	Years Ended December 31, 2024	2023
OPERATING ACTIVITIES		
Net Income	$ 36,862	$ 33,962
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	116,091	123,639
Deferred Income Taxes	863	(26,059)
Allowance for Equity Funds Used During Construction	(2,034)	(968)
Mark-to-Market of Risk Management Contracts	(11,052)	14,299
Deferred Fuel Over/Under-Recovery, Net	2,053	12,554
Change in Regulatory Assets	(12,820)	(32,887)
Change in Other Noncurrent Assets	(5,257)	(30,823)
Change in Other Noncurrent Liabilities	4,952	(9,817)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(4,616)	66,899
Fuel, Materials and Supplies	22,467	(57,893)
Margin Deposits	(1,247)	(1,966)
Accounts Payable	10,102	(23,149)
Accrued Taxes, Net	(5,427)	9,403
Other Current Assets	11,040	(685)
Other Current Liabilities	(14,943)	4,657
Net Cash Flows from Operating Activities	147,034	81,166
INVESTING ACTIVITIES		
Construction Expenditures	(191,651)	(159,770)
Other Investing Activities	1,388	881
Net Cash Flows Used for Investing Activities	(190,263)	(158,889)
FINANCING ACTIVITIES		
Capital Contribution from Parent	831	868
Return of Capital to Parent	(1,533)	(384)
Issuance of Long-term Debt - Nonaffiliated	—	435,798
Issuance of Long-term Debt - Affiliated	—	25,000
Change in Advances from Affiliates, Net	133,645	(44,861)
Retirement of Long-term Debt - Nonaffiliated	(65,000)	(340,000)
Retirement of Long-term Debt - Affiliated	(25,000)	—
Principal Payments for Finance Lease Obligations	(121)	(83)
Other Financing Activities	(75)	22
Net Cash Flows from Financing Activities	42,747	76,360
Net Decrease in Cash and Cash Equivalents	(482)	(1,363)
Cash and Cash Equivalents at Beginning of Period	1,321	2,684
Cash and Cash Equivalents at End of Period	$ 839	$ 1,321
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 76,689	$ 60,987
Net Cash Paid (Received) for Income Taxes	982	(3,413)
Noncash Acquisitions Under Finance Leases	126	503
Construction Expenditures Included in Current Liabilities as of December 31,	33,152	18,114

See Notes to Financial Statements beginning on page 10.

INDEX OF NOTES TO FINANCIAL STATEMENTS

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1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 163,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

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

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

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

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

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

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

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 in conformity with GAAP 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 credit losses, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, AROs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Inventory

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

Accounts Receivable and Allowance for Credit Losses

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 Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

Under an affiliated receivables sales arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit. AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, for KPCo. See "Securitized Accounts Receivables - AEP Credit" section of Note 12 for additional information.

Concentrations of Credit Risk and Significant Customers

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

Significant Customer of KPCo: Marathon Petroleum Company	**2024**	**2023**
Percentage of Total Revenues	15 %	15 %
Percentage of Accounts Receivable – Customers	47 %	31 %

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

Property, Plant and Equipment

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

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

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

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

Allowance for Funds Used During Construction

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. KPCo records the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Asset Retirement Obligations (ARO)

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

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances from Affiliates, Accounts Receivable and Accounts Payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

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

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

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

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

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is an expectation that refunds or recoveries will extend beyond a one year period, based on a company's filing with a commission or a commission directive. These deferrals are amortized when refunded or when billed to customers in later months with the KPSC's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the KPSC. On a routine basis, the KPSC reviews and/or audits KPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. Changes in fuel costs, including purchased power, are reflected in rates in a timely manner through the FAC. A portion of margins from off-system sales are given to customers through the FAC.

Revenue Recognition

Regulatory Accounting

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

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

Electricity Supply and Delivery Activities

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

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's 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. Realized gains and losses on cash flow hedges are recorded in Total Revenues or Purchased Electricity for Resale depending on the nature of the risk being hedged. Derivative purchases elected normal used to serve accrual based obligations are recorded in Purchased Electricity for Resale 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 Risk Management Assets or Liabilities, as appropriate, and on KPCo's statements of income in Total Revenues. Realized gains and losses on marketing and risk management transactions are included in revenues or expenses based on the transaction's facts and circumstances. However, in regulated jurisdictions subject to cost-based regulation, unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

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

Maintenance

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

Income Taxes

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

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

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

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

Excise Taxes

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

Debt

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

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

Pension and OPEB Plans

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

Investments Held in Trust for Future Liabilities

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

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

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

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

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

OPEB Plans Assets	Target
Equity	67 %
Fixed Income	32 %
Cash and Cash Equivalents	1 %

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

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

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

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

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

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

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2024 and 2023, the fair value of securities on loan as part of the program was $60 million and $62 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2024 and 2023.

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

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

Comprehensive Income (Loss)

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

Earnings Per Share (EPS)

KPCo is a wholly-owned subsidiary of AEP. Therefore, KPCo is not required to report EPS.

Supplementary Income Statement Information

The following table provides the components of Depreciation and Amortization for the years ended December 31, 2024 and 2023:

Depreciation and Amortization	Years Ended December 31, 2024	2023
	(in thousands)	
Depreciation and Amortization of Property, Plant and Equipment	$ 113,087	$ 115,984
Amortization of Regulatory Assets and Liabilities	3,004	7,655
Total Depreciation and Amortization	$ 116,091	$ 123,639

Termination of Planned Disposition of KPCo and KTCo

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

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

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

Subsequent Events

Management reviewed subsequent events through February 13, 2025, the date that KPCo's 2024 annual report was available to be issued.

2. NEW ACCOUNTING STANDARDS

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

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

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

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

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

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

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

3. RATE MATTERS

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

Investigation of the Service, Rates and Facilities of KPCo

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

2023 Kentucky Base Rate and Securitization Case

In June 2023, KPCo filed a request with the KPSC for a $93.9 million net annual increase in base rates based upon a proposed 9.9% ROE with the increase to be implemented no earlier than January 2024. In conjunction with its June 2023 filing, KPCo further requested to finance, through the issuance of securitization bonds, approximately $471.2 million of regulatory assets. KPCo's proposal did not address the disposition of its 50% interest in Mitchell Plant, which will be addressed in the future. As of December 31, 2024, the net book value of KPCo's share of the Mitchell Plant, before cost of removal including CWIP and inventory, was $547.3 million. If any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

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

In January 2024, the KPSC issued an order modifying the November 2023 uncontested settlement agreement and approving an annual base rate increase of $60 million based upon a 9.75% ROE effective with billing cycles mid-January 2024. The order reduced KPCo's base rate revenue requirement by $14.2 million to allow recovery of actual test year PJM transmission costs instead of KPCo's requested annual level of costs based on PJM 2023 projected transmission revenue requirements. In February 2024, KPCo filed an appeal with the Commonwealth of Kentucky Franklin Circuit Court, challenging among other aspects of the order, the $14.2 million base rate revenue requirement reduction. In January 2025, the Commonwealth of Kentucky Franklin Circuit Court issued an order agreeing with KPCo's appeal and remanded this issue back to the KPSC with instructions to enter an order, within 30 days, which includes setting rates to allow KPCo to recover the $14.2 million of annual PJM transmission costs effective upon KPCo's January 2024 implementation of updated base rates.

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

Fuel Adjustment Clause (FAC) Review

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

Rockport Offset Recovery

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

2024 Storm Costs

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

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

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

4. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2024	December 31, 2023	Remaining Recovery Period
	(in thousands)		
Current Regulatory Assets			
Under-recovered Fuel Costs - does not earn a return	$ 8,635	$ 10,688	1 year
Total Current Regulatory Assets	$ 8,635	$ 10,688	
Noncurrent Regulatory Assets			
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs (a)	$ 89,543	$ 78,759	
Other Regulatory Assets Pending Final Regulatory Approval	3,840	1,259	
Total Regulatory Assets Currently Not Earning a Return	93,383	80,018	
Total Regulatory Assets Pending Final Regulatory Approval	93,383	80,018	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs	180,907	171,214	16 years
Plant Retirement Costs - Asset Retirement Obligation Costs	110,510	110,280	16 years
Kentucky Deferred Purchased Power Expenses	45,011	43,512	3 years
Other Regulatory Assets Approved for Recovery	3,965	4,299	various
Total Regulatory Assets Currently Earning a Return	340,393	329,305	
Regulatory Assets Currently Not Earning a Return			
Fuel and Purchased Power Rider	57,373	61,376	2 years
Plant Retirement Costs - Asset Retirement Obligation Costs	52,294	—	16 years
Income Taxes, Net	31,106	21,796	(b)
Pension and OPEB Funded Status	13,726	24,570	12 years
Unrealized Loss on Forward Commitments	8	10,038	3 years
Other Regulatory Assets Approved for Recovery	19,930	21,122	various
Total Regulatory Assets Currently Not Earning a Return	174,437	138,902	
Total Regulatory Assets Approved for Recovery	514,830	468,207	
Total Noncurrent Regulatory Assets	$ 608,213	$ 548,225	

(a) $78.7 million of deferred storm costs related to 2020, 2021, 2022 and 2023 major storms are expected to be recovered through securitization. KPCo will seek recovery of remaining costs during the next base rate case.

(b) Recovered over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements were $2.8 million and $3.6 million for the years ended December 31, 2024 and 2023, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2024 is to be refunded over 4 years.

Regulatory Liabilities:	December 31, 2024	December 31, 2023	Remaining Refund Period
	(in thousands)		
Noncurrent Regulatory Liabilities			
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 113,130	$ 92,871	(a)
Total Regulatory Liabilities Currently Paying a Return	113,130	92,871	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Approved for Payment	5,215	4,756	various
Total Regulatory Liabilities Currently Not Paying a Return	5,215	4,756	
Total Regulatory Liabilities Approved for Payment	118,345	97,627	
Total Noncurrent Regulatory Liabilities	$ 118,345	$ 97,627	

(a) Relieved as removal costs are incurred.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

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

COMMITMENTS

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

In accordance with the accounting guidance for "Commitments", the following table summarizes KPCo's actual contractual commitments as of December 31, 2024:

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

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

GUARANTEES

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

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2024, there were no material liabilities recorded for any indemnifications.

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

ENVIRONMENTAL CONTINGENCIES

Federal EPA's Revised CCR Rule

In April 2024, the Federal EPA finalized revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities ("legacy CCR surface impoundments") as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land ("CCR management units"). The Federal EPA is requiring that owners and operators of legacy surface impoundments comply with all of the existing CCR Rule requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner

design criteria. The rule establishes compliance deadlines for legacy surface impoundments to meet regulatory requirements, including a requirement to initiate closure within five years after the effective date of the final rule. The rule requires evaluations to be completed at both active facilities and inactive facilities with one or more legacy surface impoundments. Closure may be accomplished by applying an impermeable cover system over the CCR material ("closure in place") or the CCR material may be excavated and placed in a compliant landfill ("closure by removal"). Groundwater monitoring and other analysis over the next three years will provide additional information on the planned closure method. KPCo evaluated the applicability of the rule to current and former plant sites and recorded incremental ARO in the second quarter of 2024, as shown in the table below, based on initial cost estimates primarily reflecting compliance with the rule through closure in place and future groundwater monitoring requirements pursuant to the revised CCR Rule.

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

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

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

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

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

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2024, there is one site for which KPCo has received an information request which could lead to a Potentially Responsible Party designation. In the instance where KPCo has been named a defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named for each site and several of the parties are financially sound enterprises. As of December 31, 2024, management's estimates do not anticipate material clean-up costs for the identified site.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

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

In July 2024, KPCo renewed its insurance programs including coverage for wildfire liability. Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cyber security incident or extreme weather or wildfire related liabilities. Future losses or liabilities, if they occur, which are not completely insured, unless recovered through the rate-making process, could reduce future net income and cash flows and impact financial condition.

6. BENEFIT PLANS

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

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

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

Actuarial Assumptions for Benefit Obligations

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

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

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

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

For 2024, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with an average increase of 5.75%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

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

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

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

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

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

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. The plans are monitored to control security diversification and ensure compliance with the investment policy. As of December 31, 2024, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status

For the year ended December 31, 2024, the pension plans had an actuarial loss primarily due to an unfavorable demographic experience (updated census data on January 1, 2024), specifically intra-company participant transfer activity from other AEP registrants. These losses were partially offset by the increase in the discount rate. For the year ended December 31, 2024, the OPEB plans had an actuarial gain primarily due to updated per capita cost assumptions and increases in discount rates. These gains were partially offset by the loss for intra-company participant transfer activity from other AEP registrants. For the year ended December 31, 2023, the pension plans had an actuarial loss primarily due to a decrease in the discount rate, and to a lesser extent the effect of demographic experience (updated census data on January 1, 2023). These losses were partially offset by decreasing the cash balance account interest crediting rate. For the year ended December 31, 2023, the OPEB plans had an actuarial loss primarily due to discount rates, as well as actual net benefit payments above expected. These losses were partially offset by updated per capita cost assumptions. The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

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

Amounts Recognized on the Balance Sheets

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

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

The following tables show the components of the plans included in Regulatory Assets and the items attributable to the change in these components:

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

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

Determination of Pension Expense

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

Pension and OPEB Assets

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

Pension Plan		OPEB	
December 31,			
2024	2023	2024	2023
3.0 %	2.1 %	3.3 %	2.9 %

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 327.0	$ —	$ —	$ —	$ 327.0	8.9 %
International	290.2	—	—	—	290.2	7.9 %
Common Collective Trusts (b)	176.1	—	—	472.6	648.7	17.7 %
Subtotal – Equities	793.3	—	—	472.6	1,265.9	34.5 %
Fixed Income (a):						
United States Government and Agency Securities	(2.3)	865.6	—	—	863.3	23.6 %
Corporate Debt	—	719.2	—	—	719.2	19.6 %
Foreign Debt	—	136.1	—	—	136.1	3.7 %
State and Local Government	—	25.8	—	—	25.8	0.7 %
Other – Asset Backed	—	0.9	—	—	0.9	— %
Subtotal – Fixed Income	(2.3)	1,747.6	—	—	1,745.3	47.6 %
Infrastructure (b)	—	—	—	112.9	112.9	3.1 %
Real Estate (b)	—	—	—	227.9	227.9	6.2 %
Alternative Investments (b)	—	—	—	223.8	223.8	6.1 %
Cash and Cash Equivalents (b)	—	41.3	—	27.2	68.5	1.9 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	21.9	21.9	0.6 %
Total	$ 791.0	$ 1,788.9	$ —	$ 1,086.3	$ 3,666.2	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 616.8	$ —	$ —	$ —	$ 616.8	34.7 %
International	267.2	—	—	—	267.2	15.0 %
Common Collective Trusts (a)	64.2	—	—	129.4	193.6	10.9 %
Subtotal – Equities	948.2	—	—	129.4	1,077.6	60.6 %
Fixed Income:						
Common Collective Trust Debt (a)	—	—	—	132.9	132.9	7.5 %
United States Government and Agency Securities	(0.5)	157.6	—	—	157.1	8.9 %
Corporate Debt	—	132.3	—	—	132.3	7.5 %
Foreign Debt	—	27.1	—	—	27.1	1.5 %
State and Local Government	57.8	5.0	—	—	62.8	3.5 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	57.3	322.2	—	132.9	512.4	28.9 %
Trust Owned Life Insurance:						
International Equities	—	23.1	—	—	23.1	1.3 %
United States Bonds	—	118.2	—	—	118.2	6.7 %
Subtotal – Trust Owned Life Insurance	—	141.3	—	—	141.3	8.0 %
Cash and Cash Equivalents (a)	27.6	—	—	3.1	30.7	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	13.9	13.9	0.8 %
Total	$ 1,033.1	$ 463.5	$ —	$ 279.3	$ 1,775.9	100.0 %

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

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 411.3	$ —	$ —	$ —	$ 411.3	10.0 %
International	389.8	—	—	—	389.8	9.5 %
Common Collective Trusts (b)	—	—	—	420.9	420.9	10.2 %
Subtotal – Equities	801.1	—	—	420.9	1,222.0	29.7 %
Fixed Income (a):						
United States Government and Agency Securities	8.3	1,099.2	—	—	1,107.5	26.9 %
Corporate Debt	—	894.8	—	—	894.8	21.7 %
Foreign Debt	—	167.1	—	—	167.1	4.1 %
State and Local Government	—	38.7	—	—	38.7	0.9 %
Other – Asset Backed	—	1.3	—	—	1.3	— %
Subtotal – Fixed Income	8.3	2,201.1	—	—	2,209.4	53.6 %
Infrastructure (b)	—	—	—	101.4	101.4	2.5 %
Real Estate (b)	—	—	—	239.3	239.3	5.8 %
Alternative Investments (b)	—	—	—	241.8	241.8	5.8 %
Cash and Cash Equivalents (b)	—	51.0	—	33.8	84.8	2.1 %
Other – Pending Transactions and Accrued Income (c)	—	—	0.1	19.4	19.5	0.5 %
Total	$ 809.4	$ 2,252.1	$ 0.1	$ 1,056.6	$ 4,118.2	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 540.6	$ —	$ —	$ —	$ 540.6	32.3 %
International	288.4	—	—	—	288.4	17.2 %
Common Collective Trusts (a)	—	—	—	131.6	131.6	7.9 %
Subtotal – Equities	829.0	—	—	131.6	960.6	57.4 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	146.7	146.7	8.8 %
United States Government and Agency Securities	1.4	163.3	—	—	164.7	9.8 %
Corporate Debt	—	149.0	—	—	149.0	8.9 %
Foreign Debt	—	28.6	—	—	28.6	1.7 %
State and Local Government	41.5	7.8	—	—	49.3	3.0 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.9	348.9	—	146.7	538.5	32.2 %
Trust Owned Life Insurance:						
International Equities	—	22.3	—	—	22.3	1.3 %
United States Bonds	—	130.0	—	—	130.0	7.8 %
Subtotal – Trust Owned Life Insurance	—	152.3	—	—	152.3	9.1 %
Cash and Cash Equivalents (a)	25.9	—	—	2.9	28.8	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(6.9)	(6.9)	(0.4)%
Total	$ 897.8	$ 501.2	$ —	$ 274.3	$ 1,673.3	100.0 %

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

Accumulated Benefit Obligation

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

	December 31, 2024	2023
	(in thousands)	
Qualified Pension Plan	$ 111,430	$ 89,419
Nonqualified Pension Plan	17	7
Total Accumulated Benefit Obligation	$ 111,447	$ 89,426

Obligations in Excess of Fair Values

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

Projected Benefit Obligation

	Underfunded Pension Plans	
	December 31,	
	2024	2023
	(in thousands)	
Projected Benefit Obligation	$ 114,278	$ 92,174
Fair Value of Plan Assets	109,278	87,421
Underfunded Projected Benefit Obligation	$ (5,000)	$ (4,753)

Accumulated Benefit Obligation

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

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the Pension and OPEB plans of $2.1 million and $8 thousand, respectively, during 2025. The estimated contributions to the pension trust are at least the minimum amount required by the Employee Retirement Income Security Act and additional discretionary contributions may also be made to maintain the funded status of the plan.

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

	Estimated Payments	
	Pension Plans	OPEB
	(in thousands)	
2025	$ 10,321	$ 4,232
2026	9,859	4,032
2027	10,430	3,833
2028	9,849	3,620
2029	9,810	3,509
Years 2030 to 2034, in Total	44,623	15,675

Components of Net Periodic Benefit Cost (Credit)

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

	Pension Plans		OPEB	
	Years Ended December 31,			
	2024	2023	2024	2023
	(in thousands)			
Service Cost	$ 1,604	$ 1,474	$ 56	$ 63
Interest Cost	6,127	4,814	1,373	1,269
Expected Return on Plan Assets	(9,422)	(7,131)	(3,853)	(3,201)
Amortization of Prior Service Credit	—	—	(374)	(1,856)
Amortization of Net Actuarial Loss	93	—	118	445
Settlements	1,689	—	—	—
Net Periodic Benefit Cost (Credit)	91	(843)	(2,680)	(3,280)
Capitalized Portion	(868)	(812)	(30)	(35)
Net Periodic Benefit Credit Recognized in Expense	$ (777)	$ (1,655)	$ (2,710)	$ (3,315)

American Electric Power System Retirement Savings Plan

KPCo participates in an AEPSC sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions totaled $1.4 million in 2024 and $1.4 million in 2023.

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of KPCo.

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

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

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

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

Primary Risk Exposure	December 31, 2024	December 31, 2023	Unit of Measure
	(in thousands)		
Commodity:			
Power	4,832	3,303	MWhs
Natural Gas	9,783	9,761	MMBtus
Heating Oil and Gasoline	48	253	Gallons

Cash Flow Hedging Strategies

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

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

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON KPCo's FINANCIAL STATEMENTS

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

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third-party contractual agreements and risk profiles. KPCo netted cash collateral paid to third-parties against short-term and long-term risk management liabilities in the amounts of $395 thousand and $1.2 million as of December 31, 2024 and 2023, respectively. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets as of December 31, 2024 and 2023.

The following tables represent the gross fair value of KPCo's derivative activity on the balance sheets. Unless shown as a separate line on the balance sheets due to materiality, Current Risk Management Assets are included in Prepayments and Other Current Assets, Long-term Risk Management Assets are included in Deferred Charges and Other Noncurrent Assets, Current Risk Management Liabilities are included in Other Current Liabilities and Long-term Risk Management Liabilities are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

	December 31, 2024		
Balance Sheet Location	**Risk Management Contracts – Commodity (a)**	**Gross Amounts Offset on the Balance Sheets (b)**	**Net Amounts of Assets/Liabilities Presented on the Balance Sheets (c)**
		(in thousands)	
Current Risk Management Assets	$ 6,180	$ (925)	$ 5,255
Long-term Risk Management Assets	595	(158)	437
Total Assets	6,775	(1,083)	5,692
Current Risk Management Liabilities	1,774	(1,320)	454
Long-term Risk Management Liabilities	165	(158)	7
Total Liabilities	1,939	(1,478)	461
Total MTM Derivative Contract Net Assets	$ 4,836	$ 395	$ 5,231

Balance Sheet Location	December 31, 2023 Risk Management Contracts – Commodity (a)	Gross Amounts Offset on the Balance Sheets (b)	Net Amounts of Assets/Liabilities Presented on the Balance Sheets (c)
		(in thousands)	
Current Risk Management Assets	$ 3,360	$ (296)	$ 3,064
Long-term Risk Management Assets	230	(215)	15
Total Assets	3,590	(511)	3,079
Current Risk Management Liabilities	9,375	(1,449)	7,926
Long-term Risk Management Liabilities	1,189	(215)	974
Total Liabilities	10,564	(1,664)	8,900
Total MTM Derivative Contract Net Assets (Liabilities)	$ (6,974)	$ 1,153	$ (5,821)

(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 on the balance sheets.

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

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2024	2023
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 3	$ 1
Purchased Electricity, Fuel and Other Consumables Used for Electric Generation	106	77
Other Operation	(10)	—
Maintenance	(4)	—
Regulatory Assets (a)	10,023	(10,043)
Regulatory Liabilities (a)	8,536	1,209
Total Gain (Loss) on Risk Management Contracts	$ 18,654	$ (8,756)

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

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 (Loss) 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 Total Revenues or Purchased Electricity, Fuel and Other Consumables Used for Electric Generation on KPCo's statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2024 and 2023, KPCo did not apply cash flow hedging to outstanding power derivatives.

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

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

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

Credit Risk

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

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

Credit-Risk-Related Contingent Features

Credit Downgrade Triggers

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. KPCo has not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. As of December 31, 2024 and 2023, KPCo did not have derivative contracts with collateral triggering events in a net liability position.

Cross-Acceleration Triggers

Certain interest rate derivative contracts contain cross-acceleration provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-acceleration provisions could be triggered if there was a non-performance event by KPCo under any of their outstanding debt of at least $50 million and the lender on that debt has accelerated the entire repayment obligation. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-acceleration provisions in contracts. KPCo had no derivative contracts with cross-acceleration provisions in a net liability position and no cash collateral posted as of December 31, 2024 and 2023. If a cross-acceleration provision would have been triggered, settlement at fair value would have been required.

Cross-Default Triggers

In addition, a majority of KPCo's non-exchange-traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third-party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. KPCo had derivative contracts with cross-default provisions in a net liability position of $212 thousand and $8 million, and no cash collateral posted as of December 31, 2024 and 2023, respectively. If a cross-default provision would have been triggered, settlement at fair value would have been required.

8. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

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

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

	December 31,			
	2024		2023	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 1,210,473	$ 1,222,803	$ 1,299,806	$ 1,302,987

Fair Value Measurements of Financial Assets and Liabilities

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

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2024

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 1,907	$ 4,858	$ (1,073)	$ 5,692
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 1,902	$ 27	$ (1,468)	$ 461

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

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

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Substantially comprised of power contracts.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2024	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2023	$ 2,514
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	4,022
Settlements	(6,536)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	4,831
Balance as of December 31, 2024	$ 4,831

Year Ended December 31, 2023	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2022	$ 8,463
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(62)
Settlements	(8,401)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	2,514
Balance as of December 31, 2023	$ 2,514

(a) Included in revenues on KPCo's statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Relates to the net gains (losses) of those contracts that are not reflected on KPCo's statements of income. These changes in fair value are recorded as regulatory liabilities for net gains and as regulatory assets for net losses.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of December 31, 2024 and 2023:

Significant Unobservable Inputs
December 31, 2024

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in thousands)						
FTRs	$ 4,858	$ 27	Discounted Cash Flow	Forward Market Price	$ (0.22)	$ 9.32	$ 1.08

Significant Unobservable Inputs
December 31, 2023

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in thousands)						
FTRs	$ 3,111	$ 597	Discounted Cash Flow	Forward Market Price	$ (0.03)	$ 5.05	$ 0.82

(a) Represents market prices in dollars per MWh.
(b) The weighted-average is the product of the forward market price of the underlying commodity and volume weighted by term.

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of December 31, 2024 and 2023:

Uncertainty of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

9. INCOME TAXES

Income Tax Expense (Benefit)

The details of KPCo's Income Tax Expense (Benefit) are as follows:

	Years Ended December 31, 2024	2023
	(in thousands)	
Federal:		
Current	$ 1,850	$ (2,404)
Deferred	2,166	(24,769)
Total Federal	4,016	(27,173)
State and Local:		
Current	268	788
Deferred	(1,303)	(1,290)
Total State and Local	(1,035)	(502)
Income Tax Expense (Benefit)	$ 2,981	$ (27,675)

The following is a reconciliation between the federal income taxes computed by multiplying pretax income by the federal statutory tax rate and the income taxes reported:

	Years Ended December 31, 2024	2023
	(in thousands)	
Net Income	$ 36,862	$ 33,962
Income Tax Expense (Benefit)	2,981	(27,675)
Pretax Income	$ 39,843	$ 6,287
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 8,367	$ 1,320
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Reversal of Origination Flow-Through	840	972
State and Local Income Taxes, Net	(818)	(397)
Removal Costs	1,668	(2,587)
AFUDC	(422)	(195)
Tax Reform Excess ADIT Reversal (a)	(6,626)	(25,944)
Other	(28)	(844)
Income Tax Expense (Benefit)	$ 2,981	$ (27,675)
Effective Income Tax Rate	7.5 %	(440.2)%

(a) In January 2021, as part of the 2020 Kentucky Base Rate Case, the KPSC issued an order that shortened the previously authorized refund period for Excess ADIT that is not subject to normalization requirements from 18 years to 3 years.

Net Deferred Tax Liability

The following table shows elements of the net deferred tax liability and significant temporary differences for KPCo. Amounts presented for 2023 were recast to allocate "Deferred State Income Taxes", and other miscellaneous temporary differences, amongst other categories to substantively reflect the elements of the net deferred tax liability.

	December 31, 2024	December 31, 2023
	(in thousands)	
Deferred Tax Assets	$ 82,133	$ 74,967
Deferred Tax Liabilities	(566,150)	(548,810)
Net Deferred Tax Liabilities	$ (484,017)	$ (473,843)
Property Related Temporary Differences	$ (371,937)	$ (379,093)
Amounts Due to Customers for Future Income Taxes	28,689	30,889
Regulatory Assets	(155,750)	(140,857)
Net Operating Loss Carryforward	13,016	12,344
All Other, Net	1,965	2,874
Net Deferred Tax Liabilities	$ (484,017)	$ (473,843)

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are not currently under IRS audit and the statute of limitations ("SOL") for the IRS to examine KPCo and other AEP subsidiaries' originally filed federal return has expired for tax years prior to 2017. KPCo and other AEP subsidiaries agreed to extend the SOL on the 2017-2020 tax returns to May 31, 2025, to allow the Congressional Joint Committee on Taxation ("JCT") adequate time to complete its review of the now closed IRS audit. Following JCT's approval, KPCo and other AEP subsidiaries received IRS confirmation that tax years 2017-2020 are now effectively closed as they only remain open for changes to other non-consolidated entities that KPCo and other AEP subsidiaries hold an interest in.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. KPCo and other AEP subsidiaries are not currently under any state and local income tax examinations. Generally, the SOL have expired for tax years prior to 2017. In addition, management is monitoring and continues to evaluate the potential impact of federal legislation and corresponding state conformity.

Net Income Tax Operating Loss Carryforward

KPCo has state net income tax operating loss carryforwards ("NOLC") of $178 million in 2024. As a result, KPCo recognized deferred state income tax benefits in 2024 of $9 million. This is consistent with the net operating loss carryforwards and deferred state income tax benefits recognized in 2023. Management anticipates future taxable income will be sufficient to realize the state net income tax operating loss tax benefits before the state carryforward begins expiring in 2035.

10. LEASES

KPCo leases property, plant and equipment including, but not limited to, fleet, information technology and real estate leases. These leases require payments of non-lease components, including related property taxes, operating and maintenance costs. KPCo does not separate non-lease components from associated lease components. Many of these leases have purchase or renewal options. Leases not renewed are often replaced by other leases. Options to renew or purchase a lease are included in the measurement of lease assets and liabilities if it is reasonably certain that KPCo will exercise the option.

Lease obligations are measured using the discount rate implicit in the lease when that rate is readily determinable. KPCo has visibility into the rate implicit in the lease when assets are leased from selected financial institutions under master leasing agreements. When the implicit rate is not readily determinable, KPCo measures its lease obligation using its estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk-free rate and a secured credit spread relative to the lessee on a matched maturity basis.

Operating lease rentals and finance lease amortization costs are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Interest on finance lease liabilities is generally charged to Interest Expense. Lease costs associated with capital projects are included in Property, Plant and Equipment on the balance sheets. For regulated operations with finance leases, a finance lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Finance leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs were as follows:

Lease Rental Costs	Years Ended December 31, 2024	2023
	(in thousands)	
Operating Lease Cost	$ 258	$ 71
Finance Lease Cost:		
Amortization of Finance Leases	118	83
Interest on Finance Leases	55	22
Total Lease Rental Costs (a)	$ 431	$ 176

(a) Excludes variable and short-term lease costs, which were immaterial.

Supplemental information related to leases are shown in the tables below.

Lease Type	Weighted-Average Remaining Lease Term (years):		Weighted-Average Discount Rate	
	December 31,			
	2024	2023	2024	2023
Operating Leases	4.51	5.10	5.42 %	3.49 %
Finance Leases	7.17	7.34	6.52 %	6.13 %

Cash Paid for Amounts Included in the Measurement of Lease Liabilities	Years Ended December 31, 2024	2023
	(in thousands)	
Operating Cash Flows Used for Operating Leases	$ 258	$ 71
Operating Cash Flows Used for Finance Leases	55	22
Financing Cash Flows Used for Finance Leases	121	83
Non-cash Acquisitions Under Operating Leases	$ 844	$ 639

The following tables show the property, plant and equipment under finance leases and noncurrent assets under operating leases and related obligations recorded on KPCo's balance sheets. Unless shown as a separate line on the balance sheets due to materiality, net operating lease assets are included in Deferred Charges and Other Noncurrent Assets, current finance lease obligations are included in Other Current Liabilities and long-term finance lease obligations are included in Deferred Credits and Other Noncurrent Liabilities on the balance sheets. Lease obligations are not recognized on the balance sheets for lease agreements with a lease term of less than twelve months.

	December 31, 2024	December 31, 2023
	(in thousands)	
Property, Plant and Equipment Under Finance Leases		
Generation	$ 385	$ 386
Other Property, Plant and Equipment	943	695
Total Property, Plant and Equipment Under Finance Leases	1,328	1,081
Accumulated Amortization	415	292
Net Property, Plant and Equipment Under Finance Leases	$ 913	$ 789
Obligations Under Finance Leases		
Noncurrent Liability	$ 779	$ 677
Liability Due Within One Year	134	112
Total Obligations Under Finance Leases	$ 913	$ 789

	December 31, 2024	December 31, 2023
	(in thousands)	
Operating Lease Assets	$ 1,961	$ 1,108
Obligations Under Operating Leases		
Noncurrent Liability	$ 1,795	$ 963
Liability Due Within One Year	216	195
Total Obligations Under Operating Leases	$ 2,011	$ 1,158

Future minimum lease payments consisted of the following as of December 31, 2024:

Future Minimum Lease Payments	Finance Leases	Operating Leases
	(in thousands)	
2025	$ 193	$ 465
2026	180	472
2027	164	450
2028	123	432
2029	110	313
After 2029	396	199
Total Future Minimum Lease Payments	1,166	2,331
Less: Imputed Interest	253	320
Estimated Present Value of Future Minimum Lease Payments	$ 913	$ 2,011

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of December 31, 2024, the maximum potential loss for these lease agreements was $121 thousand assuming the fair value of the equipment is zero at the end of the lease term.

Lessor Activity

KPCo's lessor activity was immaterial as of and for the years ended December 31, 2024 and December 31, 2023, respectively.

11. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding:

Type of Debt	Maturity	Weighted-Average Interest Rate as of December 31, 2024	Interest Rate Ranges as of December 31, 2024	Interest Rate Ranges as of December 31, 2023	Outstanding as of December 31, 2024	Outstanding as of December 31, 2023
					(in thousands)	
Senior Unsecured Notes	2026-2047	5.55%	3.35%-8.13%	3.13%-8.13%	$ 995,751	$1,060,225
Pollution Control Bond	2026 (a)	4.70%	4.70%	4.70%	64,756	64,588
Notes Payable - Affiliated		—%	—%	5.29%	—	25,000
Other Long-term Debt	2025	5.42%	5.42%	6.41%	149,966	149,993
Total Long-term Debt Outstanding					$1,210,473	$1,299,806

(a) KPCo's Pollution Control Bond is subject to redemption earlier than the maturity date.

As of December 31, 2024, outstanding long-term debt was payable as follows:

	2025	2026	2027	2028	2029	After 2029	Total
				(in thousands)			
Principal Amount	$ 150,000	$ 265,000	$ 40,000	$ —	$ 195,000	$ 565,000	$1,215,000
Debt Issuance Costs							(4,527)
Total Long-term Debt Outstanding							$1,210,473

Long-term Debt Subsequent Event

In January 2025, KPCo entered into a $150 million term loan due in February 2026.

Financing Plan

As of December 31, 2024, the balance sheet of KPCo reflects negative working capital primarily driven by Long-term Debt Due within One Year - Nonaffiliated, Advances from Affiliates and Accounts Payable. In January 2025, KPCo entered into a $150 million term loan to provide additional liquidity. In January 2024, the KPSC issued a financing order approving KPCo's request to securitize certain regulatory assets. KPCo expects to proceed with the securitized bond issuance process and to complete the securitization process in the first half of 2025, subject to market conditions. If completed, the securitization will provide KPCo recovery of approximately $491 million of regulatory assets; however, there is no guarantee this will occur. Accordingly, Parent, having available liquidity, has committed to provide sufficient liquidity to KPCo, as necessary, to continue operations and meet obligations as they become due until KPCo is able to execute its upcoming financing plan. Therefore, management does not believe there is a substantial doubt about KPCo's ability to continue as a going-concern and the KPCo financial statements have been prepared on a going-concern basis, which contemplates the realization of assets and the satisfaction of obligations in the normal course of business.

Dividend Restrictions

KPCo pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KPCo to transfer funds to Parent in the form of dividends.

All of the dividends declared by KPCo are subject to a Federal Power Act requirement that prohibits the payment of dividends out of capital accounts in certain circumstances; payment of dividends is generally allowed out of retained earnings.

KPCo has credit agreements that contain a covenant that limit its debt to capitalization ratio to 67.5%. As of December 31, 2024, KPCo did not exceed its debt to capitalization limit. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The most restrictive dividend limitation for KPCo is through the credit agreements. As of December 31, 2024, the maximum amount of restricted net assets of KPCo that may not be distributed to Parent in the form of a loan, advance or dividend was $671.9 million.

The Federal Power Act restriction does not limit the ability of KPCo to pay dividends out of retained earnings. The credit agreement covenant restrictions can limit the ability of KPCo to pay dividends out of retained earnings. As of December 31, 2024, the amount of any such restrictions was $95.4 million.

Corporate Borrowing Program

AEP subsidiaries use a corporate borrowing program to meet their short-term borrowing needs. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2024 and 2023 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits are described in the following table:

Years Ended December 31,	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2024	$ 206,113	$ —	$ 93,082	$ —	$ 183,212	$ 250,000
2023	169,398	243,803	112,116	243,764	49,567	250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

Years Ended December 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2024	5.79 %	4.74 %	— %	— %	5.27 %	— %
2023	5.81 %	4.66 %	5.72 %	5.72 %	5.53 %	5.72 %

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest Income, respectively, on KPCo's statements of income. For amounts borrowed from and loaned to the Utility Money Pool, KPCo incurred the following amounts of interest expense and earned the following amounts of interest income:

	Years Ended December 31, 2024	2023
	(in thousands)	
Interest Expense	$ 5,345	$ 6,399
Interest Income	—	116

Securitized Accounts Receivables – AEP Credit

Under an affiliated receivables sales arrangement, KPCo sold, without recourse, certain of its customer accounts receivable and accrued 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 credit losses is recognized within KPCo's financial statements for customer accounts receivable sold to AEP Credit, and any bad debt stemming from these receivables would be recognized by AEP Credit. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's statements of income. KPCo manages and services its accounts receivables sold.

AEP Credit's receivables securitization agreement provides a commitment of $900 million from bank conduits to purchase receivables and expires in September 2026. As of December 31, 2024, KPCo was in compliance with all requirements under the agreement.

KPCo's amounts of accounts receivable and accrued unbilled revenues under the sale of receivables agreement were $53.4 million and $42.7 million as of December 31, 2024 and 2023, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $5.0 million and $1.9 million for the years ended December 31, 2024 and 2023, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $642.8 million and $205.3 million for the years ended December 31, 2024 and 2023, respectively.

12. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Income Taxes" section of Note 1 in addition to "Corporate Borrowing Program" and "Securitized Accounts Receivables – AEP Credit" sections of Note 11.

Intercompany Billings

KPCo performs certain utility services for other AEP subsidiaries when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

Power Coordination Agreement

Effective January 1, 2014, the FERC approved the PCA. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions, while power and natural gas risk management activities for PSO and SWEPCo are allocated based on the Operating Agreement.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet and then transfers the cost to the affiliate for reimbursement. KPCo recorded its assigned portion of these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. KPCo's billed amounts were $418 thousand and $177 thousand for the years ended December 31, 2024 and 2023, respectively.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions and the net book value of all sales and purchases for the years ended December 31, 2024 and 2023 were not material. These sales and purchases are recorded in Property, Plant and Equipment on the balance sheets.

Unit Power Agreements

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all of its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The UPA will continue in effect until the debt obligations of AEGCo secured by the Rockport Plant have been satisfied and discharged (currently expected to be December 2028).

In April 2021, AEGCo and I&M executed an agreement to purchase 100% of the interests in Rockport Plant, Unit 2 effective at the end of the lease term on December 7, 2022. Beginning December 8, 2022, AEGCo and I&M applied the joint plant accounting model to their respective 50% undivided interests in the jointly owned Rockport Plant, Unit 2 as well as any future investments made prior to the current estimated retirement date of December 2028.

Prior to the termination of the lease, I&M assigned 30% of the power to KPCo as part of a UPA between AEGCo and KPCo. Beginning December 8, 2022, AEGCo billed 100% of its share of the Rockport Plant to I&M and ceased billing to KPCo. KPCo reached an agreement with I&M, from the end of the lease through May 2023, to buy capacity from Rockport Plant, Unit 2 through the PCA at a rate equal to PJM's RPM clearing price. KPCo's direct purchases from AEP East Companies through the PCA were $373 thousand and $2 million for the years ended December 31, 2024 and 2023, respectively. These direct purchases are presented as Purchased Electricity from AEP Affiliates on the statements of income.

PJM Transmission Service Charges

The AEP East Companies are parties to the TA, which defines how transmission costs through PJM OATT are allocated among the AEP East Companies on a 12-month average coincident peak basis. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to KPCo through the PJM OATT.

KPCo's net charges recorded as a result of the TA for the years ended December 31, 2024 and 2023 were $75.5 million and $66 million, respectively, and were recorded in Other Operation expenses on KPCo's statements of income.

Affiliated Revenues

The table below shows the revenues derived from auction sales to affiliates, net transmission agreement sales and other revenues as follows:

Related Party Revenues	Years Ended December 31, 2024	2023
	(in thousands)	
Transmission Agreement Sales	$ 13,283	$ 10,038
Other Revenues	1,229	1,135
Total Affiliated Revenues	$ 14,512	$ 11,173

The above summarized related party revenues are shown in Sales to AEP Affiliates on KPCo's statements of income.

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13. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a variable interest in a VIE. A VIE is a legal entity that possesses any of the following conditions: the entity's equity at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support, equity owners are unable to direct the activities that most significantly impact the legal entity's economic performance (or they possess disproportionate voting rights in relation to the economic interest in the legal entity), or the equity owners lack the obligation to absorb the legal entity's expected losses or the right to receive the legal entity's expected residual returns. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers whether KPCo has the power to direct the most significant activities of the VIE and is obligated to absorb losses or receive the expected residual returns that are significant to the VIE. Management believes that significant assumptions and judgments were applied consistently. KPCo is not the primary beneficiary of any VIE and has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC, a wholly-owned subsidiary of Parent, is consolidated by AEP. Parent is the sole equity owner of AEPSC and controls the activities of 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 the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the years ended December 31, 2024 and 2023 were $57.7 million and $46.8 million, respectively. The carrying amount of liabilities associated with AEPSC as of December 31, 2024 and 2023 were $7.7 million and $3.3 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

14. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment is shown functionally on the face of KPCo's balance sheets. The following table includes KPCo's total plant balances as of December 31, 2024 and 2023:

	December 31, 2024	2023
	(in thousands)	
Regulated Property, Plant and Equipment		
Generation	$ 1,290,637	$ 1,239,925
Transmission	950,887	838,264
Distribution	1,194,543	1,119,303
Other	173,939	173,804
CWIP	115,772	159,612
Less: Accumulated Depreciation	1,254,735	1,205,743
Total Regulated Property, Plant and Equipment - Net	2,471,043	2,325,165
Nonregulated Property, Plant and Equipment - Net	989	997
Total Property, Plant and Equipment - Net	$ 2,472,032	$ 2,326,162

Depreciation

KPCo provides for depreciation of Property, Plant and Equipment on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides total regulated annual composite depreciation rates and depreciable lives for KPCo. Nonregulated depreciation rate ranges and depreciable life ranges are not applicable or not meaningful for 2024 and 2023.

	2024		2023	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	2.7%	69 - 73	3.3%	69 - 73
Transmission	2.5%	37 - 75	2.7%	37 - 75
Distribution	3.4%	11 - 75	3.4%	11 - 75
Other	8.5%	5 - 75	8.6%	5 - 75

The composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization on the balance sheets. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability.

Asset Retirement Obligations (ARO)

In April 2024, the Federal EPA finalized revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land. In the second quarter of 2024, KPCo evaluated the applicability of the rule to current and former plant sites and incurred ARO liabilities of $64.4 million and revised cash flow estimates by an additional $3.6 million based on initial cost estimates. See the "Federal EPA's Revised CCR Rule" section of Note 6 for additional information.

The following is a reconciliation of the 2024 and 2023 aggregate carrying amounts of ARO for KPCo:

Year	ARO as of January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled (a)	Revisions in Cash Flow Estimates (a)	ARO as of December 31,
			(in thousands)			
2024	$ 18,276	$ 2,587	$ 66,399	$ (924)	$ 2,495	$ 88,833
2023	18,477	811	—	(1,088)	76	18,276

(a) Unless discussed above, primarily related to ash pond closure and asbestos abatement.

Allowance for Funds Used During Construction

KPCo's amounts of allowance for equity and borrowed funds used during construction are summarized in the following table:

	Years Ended December 31, 2024	2023
	(in thousands)	
Allowance for Equity Funds Used During Construction	$ 2,034	$ 968
Allowance for Borrowed Funds Used During Construction	3,922	4,838

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 Property, Plant and Equipment as follows:

	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
KPCo's Share as of December 31, 2024					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,088,611	$ 3,680	$ 545,520
KPCo's Share as of December 31, 2023					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 1,055,915	$ 21,596	$ 534,308

(a) Operated by WPCo.

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, 2024	2023
	(in thousands)	
Retail Revenues:		
Residential Revenues	$ 278,699	$ 246,124
Commercial Revenues	190,145	159,443
Industrial Revenues	167,490	149,336
Other Retail Revenues	2,147	1,979
Total Retail Revenues	638,481	556,882
Wholesale Revenues:		
Generation Revenues	15,049	12,686
Transmission Revenues (a)	30,070	28,799
Total Wholesale Revenues	45,119	41,485
Other Revenues from Contracts with Customers (b)	9,302	11,428
Total Revenues from Contracts with Customers	692,902	609,795
Other Revenues:		
Alternative Revenue Programs (c)	2,880	5,052
Other Revenues	3	2
Total Other Revenues	2,883	5,054
Total Revenues	$ 695,785	$ 614,849

(a) Amounts include affiliated and nonaffiliated revenues. The affiliated revenues were $13.8 million and $17 million for years ended December 31, 2024 and 2023, respectively.
(b) Amounts include affiliated and nonaffiliated revenues.
(c) Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over/under collection of related revenues.

Performance Obligations

KPCo has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for "Revenue from Contracts with Customers" allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity's measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. KPCo elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for KPCo are summarized as follows:

Retail Revenues

KPCo has performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer's usage requirements.

Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between KPCo and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice.

Wholesale Revenues - Generation

KPCo has performance obligations to sell electricity to wholesale customers from generation assets in PJM. The performance obligation to deliver electricity from generation assets is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Wholesale generation revenues are variable as they are subject to the customer's usage requirements.

KPCo also has performance obligations to stand ready in order to promote grid reliability. Stand ready services are sold into PJM's RPM capacity market. RPM entails a base auction and at least three incremental auctions for a specific PJM delivery year, with the incremental auctions spanning three years. The performance obligation to stand ready is satisfied over time and the consideration for which is variable until the occurrence of the final incremental auction, at which point the performance obligation becomes fixed.

Payments from the RTO for stand ready services are typically received within one week from the issuance of the invoice, which is typically issued weekly. Gross margin resulting from generation sales are primarily subject to margin sharing agreements with customers, where the revenues are reflected gross in the disaggregated revenues table above.

Wholesale Revenues - Transmission

KPCo has performance obligations to transmit electricity to wholesale customers through assets owned and operated by KPCo and other AEP subsidiaries. The performance obligation to provide transmission services in PJM is partially fixed for a period of one year or less. Payments from the RTO for transmission services are typically received within one week from the issuance of the invoice, which is issued weekly for PJM.

KPCo collects revenues through transmission formula rates. The FERC-approved rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations," and are therefore presented as such in the disaggregated revenues table above.

The AEP East Companies are parties to the TA, which defines how transmission costs are allocated among the AEP East Companies on a 12-month average coincident peak basis. AEPTCo is a load serving entity within PJM providing transmission services to affiliates in accordance with the OATT and TA. Affiliate revenues as a result of the TA are reflected as Transmission Revenues in the disaggregated revenues table above.

Fixed Performance Obligations

The following table represents KPCo's remaining fixed performance obligations satisfied over time as of December 31, 2024. Fixed performance obligations primarily include electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. KPCo elected to apply the exemption to not disclose the value of unsatisfied performance obligations for contracts with an original expected term of one year or less. Due to the annual establishment of revenue requirements, transmission revenues are excluded from the table below. The amounts shown in the table below include affiliated and nonaffiliated revenues.

2025	2026-2027	2028-2029	After 2029	Total
		(in thousands)		
$ 1,435	$ 2,870	$ 2,870	$ 1,435	$ 8,610

Contract Assets and Liabilities

Contract assets are recognized when KPCo has a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. KPCo did not have material contract assets as of December 31, 2024 and 2023, respectively.

When KPCo receives consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheet in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. KPCo's contract liabilities typically arise from advanced payments of services provided primarily with respect to joint use agreements for utility poles. KPCo did not have material contract liabilities as of December 31, 2024 and 2023, respectively.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on KPCo's balance sheets within the Accounts Receivable - Customers line item. KPCo's balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Accounts Receivable - Customers were not material as of December 31, 2024 and 2023, respectively. See "Securitized Accounts Receivable - AEP Credit" section of Note 11 for additional information.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable - Affiliated Companies on KPCo's balance sheets were $14.1 million and $12.2 million, respectively, as of December 31, 2024 and December 31, 2023.

Contract Costs

Contract costs to obtain or fulfill a contract are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and neither bifurcated nor reclassified between current and noncurrent assets 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 Other Operation on KPCo's statements of income. KPCo did not have material contract costs as of December 31, 2024 and 2023, respectively.

July 31st, 2024

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed June 2024 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:	
1-12	Income Statement
1-3	Details of Operating Revenues
5-10	Operating Expenses – Functional Expenses
12	Detail Statement of Taxes
Balance Sheet:	
13	Balance Sheet – Assets & Other Debits
13-15	Balance Sheet – Liabilities & Other Credits
14-15	Deferred Credits
15	Statement of Retained Earnings
Utility Property:	
16-17	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Digitally signed by Brian J. Frantz
DN: cn=Brian J. Frantz, c=US, o=AEP, ou=Corporate Accounting, email=bjfrantz@aep.com
Reason: I have reviewed this document
Date: 2024.07.31 09:57:14 -04'00'

Brian J Frantz
Director - Corporate Accounting

American Electric Power

INCOME STATEMENT

IS8016 YTD Jun 2024 07/26/2024 13:14			Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
		Layout: IS8016				
17A V2099-01-01		Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024
		REVENUES				
4400001		Residential Sales-W/Space Htg	71,926,293	71,926,293	0	0
4400002		Residential Sales-W/O Space Ht	30,642,267	31,443,801	(801,533)	0
4400005		Residential Fuel Rev	37,101,100	37,101,100	0	0
	A	**Revenue - Residential Sales**	**139,669,660**	**140,471,194**	**(801,533)**	**-**
4420001		Commercial Sales	48,214,128	48,845,798	(631,671)	0
4420006		Sales to Pub Auth - Schools	7,924,214	7,924,214	0	0
4420007		Sales to Pub Auth - Ex Schools	9,717,956	9,717,956	0	0
4420013		Commercial Fuel Rev	27,481,756	27,481,756	0	0
	A	**Revenue - Commercial Sales**	**93,338,055**	**93,969,726**	**(631,671)**	**-**
	B	**Revenue - Industrial Sales - Affiliated**	**-**	**-**	**-**	**-**
4420002		Industrial Sales (Excl Mines)	34,222,677	35,150,150	(927,473)	0
4420004		Ind Sales-NonAffil(Incl Mines)	9,272,783	9,272,783	0	0
4420016		Industrial Fuel Rev	38,481,546	38,481,546	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**81,977,005**	**82,904,478**	**(927,473)**	**-**
		Revenue - Industrial Sales	**81,977,005**	**82,904,478**	**(927,473)**	**-**
	A	**Revenue - Gas Products Sales**	**-**	**-**	**-**	**-**
	A	**Revenue - Gas Transportation & Storage Sales**	**-**	**-**	**-**	**-**
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	**-**	**-**	**-**	**-**
4440000		Public Street/Highway Lighting	897,792	901,458	(3,666)	0
4440002		Public St & Hwy Light Fuel Rev	169,178	169,178	0	0
	A	**Revenue - Other Retail Sales**	**1,066,970**	**1,070,636**	**(3,666)**	**-**
	B	**Revenue - Other Retail Sales - Affiliated**	**-**	**-**	**-**	**-**
		Revenue - Retail Sales	**316,051,690**	**318,416,034**	**(2,364,343)**	**-**
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	40,679,613
4561033		PJM NITS Revenue - Affiliated	36,662,554	0	0	36,662,554
4561034		PJM TO Adm. Serv Rev - Aff	124,707	0	0	124,707
4561035		PJM Affiliated Trans NITS Cost	(30,218,775)	0	(30,218,775)	0
4561036		PJM Affiliated Trans TO Cost	(83,202)	0	(83,202)	0
4561059		Affil PJM Trans Enhancmnt Rev	781,523	0	0	781,523
4561060		Affil PJM Trans Enhancmnt Cost	(644,163)	0	(644,163)	0
4561062		PROVISION RTO Cost - Affi	178,378	0	178,378	0
4561063		PROVISION RTO Rev Affiliated	2,040,274	0	0	2,040,274
	B	**Revenue - Transmission-Affiliated**	**8,841,296**	**-**	**(30,767,763)**	**80,288,672**
4470150		Transm. Rev.-Dedic. Whlsl/Muni	98,639	0	(1,275,738)	1,374,376
4470206		PJM Trans loss credits-OSS	26,691	0	26,691	0
4470209		PJM transm loss charges-OSS	(77,079)	0	(77,079)	0
4561005		PJM Point to Point Trans Svc	1,172,191	0	1,172,191	0
4561006		PJM Trans Owner Admin Rev	45,090	0	0	45,090
4561007		PJM Network Integ Trans Svc	5,505,565	0	0	5,505,565
4561019		Oth Elec Rev Trans Non Affil	26,535	0	0	26,535
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	1,382	0	0	1,382
4561029		PJM NITS Revenue Whsl Cus-NAff	1,231,497	0	0	1,231,497
4561030		PJM TO Serv Rev Whls Cus-NAff	4,609	0	0	4,609
4561058		NonAffil PJM Trans Enhncmt Rev	859,033	0	0	859,033
4561061		NAff PJM RTEP Rev for Whsl-FR	26,251	0	0	26,251
4561064		PROVISION RTO Rev WhslCus-NAf	68,568	0	0	68,568

American Electric Power

INCOME STATEMENT

IS8016
YTD Jun 2024
07/26/2024 13:14

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Jun 2024	Kentucky Power Company - Distribution 110 Actual YTD Jun 2024	Kentucky Power Company - Generation 117 Actual YTD Jun 2024	Kentucky Power Company - Transmission 180 Actual YTD Jun 2024
4561065		PROVISION RTO Rev - NonAff	302,370	0	(1)	302,371
	A	**Revenue - Transmission-NonAffiliated**	**9,291,343**	**-**	**(153,935)**	**9,445,278**
		Revenue - Transmission	**18,132,639**	**-**	**(30,921,698)**	**89,733,950**
4470151		Trading Auction Sales Affil	114,213	0	114,213	0
	B	**Revenue - Resale-Affiliated**	**114,213**	**-**	**114,213**	**-**
4470010		Sales for Resale-Bookout Purch	(19)	0	(19)	0
4470027		Whsal/Muni/Pb Ath Fuel Rev	1,303,283	0	1,303,283	0
4470033		Whsal/Muni/Pub Auth Base Rev	774,505	0	774,505	0
4470082		Financial Electric Realized	(3,102)	0	(3,102)	0
4470089		PJM Energy Sales Margin	819,355	0	819,355	0
4470098		PJM Oper.Reserve Rev-OSS	(14,107)	0	(14,107)	0
4470100		PJM FTR Revenue-OSS	71,459	0	71,459	0
4470103		PJM Energy Sales Cost	5,215,148	0	5,215,148	0
4470110		PJM TO Admin. Exp.-NonAff.	4	0	4	0
4470115		PJM Meter Corrections-OSS	(8,697)	0	(8,697)	0
4470116		PJM Meter Corrections-LSE	(195,828)	0	(195,828)	0
4470126		PJM Incremental Imp Cong-OSS	(78,824)	0	(78,824)	0
4470175		OSS Sharing Reclass - Retail	3,144,172	0	3,144,172	0
4470176		OSS Sharing Reclass-Reduction	(3,144,172)	0	(3,144,172)	0
4470215		PJM 30m Suppl Reserve CH OSS	2,731	0	2,731	0
4470220		PJM Regulation - OSS	2,302,047	0	2,302,047	0
4470221		PJM Spinning Reserve - OSS	23,652	0	23,652	0
5550080		PJM Hourly Net Purch.-FERC	(2,554,476)	0	(2,554,476)	0
	A	**Revenue - Resale-NonAffiliated**	**7,657,131**	**-**	**7,657,131**	**-**
	A	**Revenue - Resale-Realized**	**-**	**-**	**-**	**-**
	A	**Revenue - Resale-Risk Mgmt MTM**	**-**	**-**	**-**	**-**
	A	**Revenue - Resale-Risk Mgmt Activities**	**-**	**-**	**-**	**-**
		Revenue - Sales for Resale	**7,771,344**	**-**	**7,771,344**	**-**
4470074		Sale for Resale-Aff-Trnf Price	0	0	208,795,726	0
4540001		Rent From Elect Property - Af	581,082	459,022	0	249,264
	B	**Revenue - Other Ele-Affilliated**	**581,082**	**459,022**	**208,795,726**	**249,264**
4500000		Forfeited Discounts	412,573	412,573	0	0
4510001		Misc Service Rev - Nonaffil	74,353	73,909	0	444
4540002		Rent From Elect Property-NAC	1,957,160	1,550	1,936,335	19,275
4540005		Rent from Elec Prop-Pole Attch	2,498,576	2,494,717	0	3,860
4560007		Oth Elect Rev - DSM Program	295,823	295,823	0	0
5010040		Gas Procuremnt Sales Net	(1,140,697)	0	(1,140,697)	0
		Revenue - Other Ele-NonAffilliated	**4,097,789**	**3,278,572**	**795,638**	**23,579**
		Revenue - Gas	**-**	**-**	**-**	**-**
4118002		Comp. Allow Gains Title IV SO2	14	14	0	0
		Gain/(Loss) on Allowances	**14**	**14**	**-**	**-**
	A	**Revenue - Other Ele-NonAffilliated**	**4,097,803**	**3,278,586**	**795,638**	**23,579**
		Revenue - Other Opr Electric	**4,678,885**	**3,737,608**	**209,591,364**	**272,843**
	D	**Revenue Merchandising & Contract Work**	**-**	**-**	**-**	**-**
	C	**Revenues Non-Utility Operations - Affiliated**	**-**	**-**	**-**	**-**
4170004		Rev from Non-Util Oper NonAfil	165,275	165,275	0	0
	D	**Revenues Non-Utility Operations - NonAffiliated**	**165,275**	**165,275**	**-**	**-**

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Filing Requirements
Exhibit R
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American Electric Power

IS8016 YTD Jun 2024 07/26/2024 13:14	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024
	Revenues from Non-Utility Operations	**165,275**	**165,275**	**-**	**-**
C	**Non-Operating Rental Income - Affiliated**	**-**	**-**	**-**	**-**
4180001	Non-Operatng Rental Income	400	400	0	0
4180005	Non-Opratng Rntal Inc-Depr	(3,335)	0	0	(3,335)
D	**Non-Operating Rental Income - NonAffiliated**	**(2,935)**	**400**	**-**	**(3,335)**
	Non-Operating Rental Income	**(2,935)**	**400**	**-**	**(3,335)**
C	**Non-Operating Misc Income -Affiliated**	**-**	**-**	**-**	**-**
4210002	Misc Non-Op Inc-NonAsc-Rents	962	288	505	170
4210007	Misc Non-Op Inc - NonAsc - Oth	6,427	678	5,750	0
D	**Non-Operating Misc Income - NonAffiliated**	**7,390**	**965**	**6,255**	**170**
	Non-Operating Misc Income	**7,390**	**965**	**6,255**	**170**
4540004	Rent From Elect Prop-ABD-Nonaf	(16,326)	(16,326)	0	0
4560015	Other Electric Revenues - ABD	335,974	332,974	0	3,000
D	**Associated Business Development Income**	**319,648**	**316,648**	**-**	**3,000**
	Revenue - Other Opr - Other	**489,378**	**483,289**	**6,255**	**(165)**
=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	**-**	**-**	**-**	**-**
=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***489,378***	***483,289***	***6,255***	***(165)***
	Revenue - Other Operating	**5,168,263**	**4,220,897**	**209,597,619**	**272,678**
4491002	Prov Rate Refund-Nonaffiliated	(101,351)	0	0	(101,351)
4491003	Prov Rate Refund - Retail	(23,079)	0	0	(23,079)
A	**Provision for Rate Refund - NonAffiliated**	**(124,430)**	**-**	**-**	**(124,430)**
4491004	Prov Rate Refund - Affiliated	(679,515)	0	0	(679,515)
B	**Provision for Rate Refund - Affiliated**	**(679,515)**	**-**	**-**	**(679,515)**
	Provision for Rate Refund	**(803,945)**	**-**	**-**	**(803,945)**
A	**Revenue - Power Sales**	**-**	**-**	**-**	**-**
	TOTAL OPERATING REVENUES	**346,319,992**	**322,636,930**	**184,082,922**	**89,202,683**
=(A)	*Memo: G/T/D Revenue*	*336,973,538*	*321,694,620*	*5,934,491*	*9,344,427*
=(B)	*Memo: Other Affiliated Revenue*	*8,857,075*	*459,022*	*178,142,176*	*79,858,421*
=(C)	*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
=(D)	*Memo: Revenue-Oth Opr-Oth Nor*	*489,378*	*483,289*	*6,255*	*(165)*
	Memo: Total Operating Revenues	*346,319,992*	*322,636,930*	*184,082,922*	*89,202,683*
=(E)=(B)+(C)	*Memo: Affiliated Revenue*	***8,857,075***	***459,022***	***178,142,176***	***79,858,421***
=(F)=(D)+(A)	*Memo: Non-Affiliated Revenue*	***337,462,916***	***322,177,908***	***5,940,746***	***9,344,262***
	Memo: Total Operating Revenues	***346,319,992***	***322,636,930***	***184,082,922***	***89,202,683***
	FUEL EXPENSES				
5010000	Fuel	3,075,236	2	3,075,232	1
5010001	Fuel Consumed	38,287,181	0	38,287,181	0
5010003	Fuel - Procure Unload & Handle	1,495,328	0	1,495,328	0
5010012	Ash Sales Proceeds	8,544	0	8,544	0
5010013	Fuel Survey Activity	49,281	0	49,281	0
5010019	Fuel Oil Consumed	1,812,453	0	1,812,453	0
5010020	Nat Gas Consumed Steam	17,131,281	0	17,131,281	0
5010021	Transp Gas Consumed Steam	517,265	0	517,265	0
5010027	Gypsum handling/disposal costs	681,066	0	681,066	0
5010028	Gypsum Sales Proceeds	(669,523)	0	(669,523)	0

KPSC Case No. 2025-00257
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Filing Requirements
Exhibit R
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American Electric Power

INCOME STATEMENT

IS8016
YTD Jun 2024
07/26/2024 13:14

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Jun 2024	Kentucky Power Company - Distribution 110 Actual YTD Jun 2024	Kentucky Power Company - Generation 117 Actual YTD Jun 2024	Kentucky Power Company - Transmission 180 Actual YTD Jun 2024
5010034	Gas Transp Res Fees-Steam	3,149,567	0	3,149,567	0
	Fuel Expense Total	**65,537,678**	**2**	**65,537,674**	**1**
5010005	Fuel - Deferred	3,875,937	0	3,875,937	0
	Deferred Fuel Expense	**3,875,937**	**-**	**3,875,937**	**-**
	Over Under Fuel Expense				
	Fuel for Electric Generation	**69,413,616**	**2**	**69,413,612**	**1**
	Fuel from Affiliates for Electric Generation	**-**	**-**	**-**	**-**
5090000	Allow Consum Title IV SO2	12,968	0	12,968	0
5090009	Allow Consumpt CSAPR SO2	62	0	62	0
5570009	Other Pwr Exp- REC's - RETAIL	446	0	446	0
	Allowances - Consumption	**13,477**	**-**	**13,477**	**-**
5020002	Urea Expense	666,007	0	666,007	0
5020004	Lime-Related Expenses	875,452	0	875,452	0
	Emissions Control - Chemicals	**1,541,459**	**-**	**1,541,459**	**-**
	Total Fuel for Electric Generation	**70,968,552**	**2**	**70,968,548**	**1**
	Memo: NonAff Fuel/Allow/Emissions	***70,968,552***	***2***	***70,968,548***	***1***
5550004	Purchased Power-Pool Capacity	373,078	0	373,078	0
5550029	Purch Power-Assoc-Trnsfr Price	0	208,795,726	0	0
	Purchased Electricity from AEP - Affiliates	**373,078**	**208,795,726**	**373,078**	**-**
5550001	Purch Pwr-NonTrading-Nonassoc	45,340,287	0	45,340,287	0
5550023	Purch Power Capacity -NA	220,058	0	220,058	0
5550039	PJM Inadvertent Mtr Res-OSS	1,538	0	1,538	0
5550040	PJM Inadvertent Mtr Res-LSE	22,786	0	22,786	0
5550074	PJM Reactive-Charge	1,847,369	0	1,847,369	0
5550075	PJM Reactive-Credit	(717,438)	0	(717,438)	0
5550076	PJM Black Start-Charge	525,284	0	525,284	0
5550078	PJM Regulation-Charge	304,407	0	304,407	0
5550079	PJM Regulation-Credit	(9,415)	0	(9,415)	0
5550083	PJM Spinning Reserve-Charge	219,150	0	219,150	0
5550084	PJM Spinning Reserve-Credit	(13,998)	0	(13,998)	0
5550123	PJM OpRes-LSE-Charge	821,691	0	820,365	1,326
5550124	PJM Implicit Congestion-LSE	2,475,133	0	2,475,133	0
5550132	PJM FTR Revenue-LSE	(3,770,708)	0	(3,770,708)	0
5550137	PJM OpRes-LSE-Credit	(36,064)	0	(36,064)	0
5550153	PurchPower-Rockport Def-NonAff	152,680	0	152,680	0
5550326	PJM Transm Loss Charges - LSE	2,764,770	0	2,764,770	0
5550327	PJM Transm Loss Credits-LSE	(1,044,887)	0	(1,044,887)	0
5550328	PJM FC Penalty Credit	(2,395)	0	(2,395)	0
	Purchased Electricity for Resale - NonAffiliated	**49,100,248**	**-**	**49,098,922**	**1,326**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**
	Purchased Gas for Resale - NonAffiliated	**-**	**-**	**-**	**-**
	Total Purchased Power	**49,473,326**	**208,795,726**	**49,472,000**	**1,326**
	GROSS MARGIN	**225,878,114**	**113,841,202**	**63,642,374**	**89,201,356**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	2,337,085	(22,310)	2,354,860	4,536
5020000	Steam Expenses	790,188	0	790,188	0

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INCOME STATEMENT

IS8016
YTD Jun 2024
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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Jun 2024	Kentucky Power Company - Distribution 110 Actual YTD Jun 2024	Kentucky Power Company - Generation 117 Actual YTD Jun 2024	Kentucky Power Company - Transmission 180 Actual YTD Jun 2024
5050000	Electric Expenses	18,281	0	18,281	0
5060000	Misc Steam Power Expenses	3,638,706	61,106	3,573,756	3,844
5060002	Misc Steam Power Exp-Assoc	26,754	0	26,754	0
5060004	NSR Settlement Expense	10,130	0	10,130	0
5060011	BSRR O/U Recovery-Oper Costs	367	0	367	0
	Steam Generation Op Exp	**6,821,511**	**38,795**	**6,774,336**	**8,380**
	Nuclear Generation Op Exp	**-**	**-**	**-**	**-**
	Hydro Generation Op Exp	**-**	**-**	**-**	**-**
5560000	Sys Control & Load Dispatching	30,871	0	30,871	0
5570000	Other Expenses	458,059	0	458,059	0
5570007	Other Pwr Exp - Wholesale RECs	245	245	0	0
5570010	OH Auction Exp - Incremental	6	0	6	0
5757000	PJM Admin-MAM&SC- OSS	32,264	0	32,264	0
5757001	PJM Admin-MAM&SC- Internal	732,040	0	732,040	0
	Other Generation Op Exp	**1,253,484**	**245**	**1,253,239**	**-**
5600000	Oper Supervision & Engineering	1,090,897	30,313	11,780	1,048,804
5612000	Load Dispatch-Mntr&Op TransSys	188,884	2,496	332	186,057
5614000	PJM Admin-SSC&DS-OSS	39,320	0	39,320	0
5614001	PJM Admin-SSC&DS-Internal	730,572	0	730,572	0
5614009	GreenHat Settlement	3,535	0	3,535	0
5615000	Reliability,Plng&Stds Develop	34,565	779	104	33,681
5618000	PJM Admin-RP&SDS-OSS	11,401	0	11,401	0
5618001	PJM Admin-RP&SDS- Internal	239,479	0	239,479	0
5620001	Station Expenses - Nonassoc	109,810	(0)	(1)	109,812
5630000	Overhead Line Expenses	13,605	(0)	(0)	13,606
5650002	Transmssn Elec by Others-NAC	47,706	0	47,706	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	40,679,613	0	0
5650012	PJM Trans Enhancement Charge	1,038,287	0	1,038,287	0
5650015	PJM TO Serv Exp - Aff	83,581	0	83,581	0
5650016	PJM NITS Expense - Affiliated	37,119,876	0	37,119,876	0
5650019	Affil PJM Trans Enhncement Exp	2,749,495	0	2,749,495	0
5650020	PROVISION RTO Affl Expense	(2,938,297)	0	(2,938,297)	0
5650021	PJM NITS Expense - Non-Affilia	433,230	0	433,230	0
5650023	Amort of PROVISION RTO Expense	27,405	0	27,405	0
5660000	Misc Transmission Expenses	807,184	116,733	1,812	688,639
5660009	PJM OATT LSE Over-Under Adjust	1,248,885	0	1,248,885	0
5660011	Misc Transm Exp - Affiliate	1,824	0	0	1,824
5670002	Rents - Associated	0	0	0	127,205
	Transmission Op Exp	**43,081,245**	**40,829,933**	**40,848,503**	**2,209,628**
5800000	Oper Supervision & Engineering	433,786	432,400	412	1,007
5820000	Station Expenses	174,178	173,284	16	879
5830000	Overhead Line Expenses	150,424	150,601	(1)	14
5840000	Underground Line Expenses	172,773	172,861	67	(154)
5850000	Street Lighting & Signal Sys E	16,335	16,337	0	0
5860000	Meter Expenses	746,318	746,928	35	45
5870000	Customer Installations Exp	112,799	112,887	3	(38)
5880000	Miscellaneous Distribution Exp	4,193,970	4,189,655	500	4,151

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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Jun 2024	Kentucky Power Company - Distribution 110 Actual YTD Jun 2024	Kentucky Power Company - Generation 117 Actual YTD Jun 2024	Kentucky Power Company - Transmission 180 Actual YTD Jun 2024
5890001	Rents - Nonassociated	448,987	448,987	0	0
5890002	Rents - Associated	54,557	54,557	0	0
	Distribution Op Exp	**6,504,128**	**6,498,497**	**1,031**	**5,903**
9010000	Supervision - Customer Accts	4,064	4,048	3	12
9020000	Meter Reading Expenses	16,049	16,049	0	0
9020002	Meter Reading - Regular	151,760	151,816	0	0
9020003	Meter Reading - Large Power	18,678	18,678	0	0
9030000	Cust Records & Collection Exp	152,900	151,035	(2)	1,867
9030001	Customer Orders & Inquiries	1,557,350	1,557,104	73	196
9030002	Manual Billing	6,260	6,230	16	15
9030003	Postage - Customer Bills	300,088	300,088	0	0
9030004	Cashiering	27,601	27,601	0	0
9030005	Collection Agents Fees & Exp	1,271	1,271	0	0
9030006	Credit & Oth Collection Activi	349,222	349,476	0	0
9030007	Collectors	176,789	176,789	0	0
9030009	Data Processing	17,609	17,604	5	5
9040007	Uncoll Accts - Misc Receivable	7,570	7,476	6	88
9050000	Misc Customer Accounts Exp	11,017	11,017	0	0
9070000	Supervision - Customer Service	30,424	30,431	(2)	(2)
9080000	Customer Assistance Expenses	662,812	662,835	0	0
9080009	Cust Assistance Expense - DSM	314,493	314,495	0	0
9100000	Misc Cust Svc&Informational Ex	3,115	1,461	850	804
	Customer Service and Information Op Exp	**3,809,071**	**3,805,504**	**949**	**2,986**
9120000	Demonstrating & Selling Exp	5,455	5,455	0	0
9120003	Demo & Selling Exp - Area Dev	20	20	0	0
9130001	Advertising Exp - Residential	80	72	7	1
	Sales Expenses	**5,555**	**5,547**	**7**	**1**
	Memo: Insurance (9240 9250)	**1,604,681**	**884,385**	**580,969**	**139,327**
9200000	Administrative & Gen Salaries	6,606,849	3,115,793	2,441,499	1,049,565
9210001	Off Supl & Exp - Nonassociated	424,800	306,272	86,532	32,015
9210003	Office Supplies & Exp - Trnsf	141	51	62	28
9210021	EMP TRAVEL - Airfare	37	18	14	4
9210022	MEALS & ENT-100 Pct DEDUCTIBLE	71	23	37	11
9210023	EMP TRAVEL-MILEAGE	468	235	144	88
9210024	EMP TRAVEL-PARKING	10	5	4	1
9210025	MEALS & ENT-50 Pct DEDUCTIBLE	35	21	12	2
9210026	EMP TRAVEL-CAR RENTAL	16	8	6	2
9210027	EMP TRAVEL-TAXI AND SHUTTLE	3	1	1	0
9210028	EMP TRAVEL-HOTEL & LODGING	469	188	210	72
9210030	EMP TRAVEL-OTHER	43	39	3	0
9210031	SAFETY EQUIPMENT AND SUPPLIES	7	2	4	1
9210032	FUEL	3	2	1	0
9210033	FOOD SERVICE-CATERING	5	2	2	1
9210034	In-House Training & Seminars	52	0	0	52
9210037	OEM/TECHNICAL TRAINING	23	0	0	23
9210040	DUES-BUSINESS/PROFESSIONAL	3	1	1	1
9220000	Administrative Exp Trnsf - Cr	(93,074)	(93,074)	0	0

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IS8016 YTD Jun 2024 07/26/2024 13:14	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024
9220001	Admin Exp Trnsf to Cnstrction	(250,919)	(250,919)	0	0
9220004	Admin Exp Trnsf to ABD	92	92	0	0
9220005	Overhead Loadings	(347,462)	(232,675)	(98,913)	(15,874)
9230001	Outside Svcs Empl - Nonassoc	1,553,044	376,138	569,841	607,065
9230003	AEPSC Billed to Client Co	149,185	46,059	38,202	64,925
9230034	SRV-SOFTWARE LICENSING	13,987	10,269	3,601	117
9230035	Development Project Expense	116	0	0	116
9240000	Property Insurance	591,340	143,141	347,394	100,805
9250000	Injuries and Damages	883,273	614,934	231,234	37,105
9250002	Emp Accdent Prvntion-Adm Exp	42	15	13	14
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	213,252	202,389	9,344	1,518
9250007	Prsnal Injries&Prop Dmage-Pub	8,112	0	8,112	0
9250010	Frg Ben Loading - Workers Comp	(91,339)	(76,095)	(15,128)	(116)
9260000	Employee Pensions & Benefits	1,272	1,272	0	0
9260001	Edit & Print Empl Pub-Salaries	6	6	0	0
9260002	Pension & Group Ins Admin	14,508	6,665	7,619	224
9260003	Pension Plan	1,069,464	717,141	344,072	8,250
9260004	Group Life Insurance Premiums	71,022	45,298	25,360	365
9260005	Group Medical Ins Premiums	2,504,574	1,708,103	775,231	21,241
9260007	Group L-T Disability Ins Prem	261,924	157,355	104,332	237
9260009	Group Dental Insurance Prem	88,274	60,454	27,001	818
9260010	Training Administration Exp	6,625	4,155	2,159	311
9260012	Employee Activities	7,245	5,684	1,412	149
9260021	Postretirement Benefits - OPEB	46,203	25,162	20,403	639
9260027	Savings Plan Contributions	924,235	608,254	309,197	6,784
9260036	Deferred Compensation	4,285	4,285	0	0
9260037	Supplemental Pension	12,426	12,396	30	0
9260050	Frg Ben Loading - Pension	(499,643)	(430,539)	(62,056)	(7,048)
9260051	Frg Ben Loading - Grp Ins	(1,368,606)	(1,177,742)	(173,069)	(17,794)
9260052	Frg Ben Loading - Savings	(397,941)	(337,649)	(54,025)	(6,267)
9260053	Frg Ben Loading - OPEB	(44,198)	(36,532)	(6,890)	(776)
9260055	IntercoFringeOffset- Don't Use	(251,619)	(251,619)	0	0
9260058	Frg Ben Loading - Accrual	(27,534)	(21,132)	(6,128)	(274)
9260060	Amort-Post Retirerment Benefit	108,310	64,791	35,603	7,916
9270000	Franchise Requirements	79,905	79,905	0	0
9280000	Regulatory Commission Exp	2,691	1,203	733	755
9280001	Regulatory Commission Exp-Adm	3	0	0	3
9280002	Regulatory Commission Exp-Case	1,904,970	986,561	425,859	492,552
9280005	Reg Com Exp-FERC Trans Cases	8,640	116	134	8,390
9280006	State Publ Serv CommissionFees	474,603	474,603	0	0
9301000	General Advertising Expenses	9,064	4,080	2,583	2,401
9301001	Newspaper Advertising Space	20,000	9,047	5,530	5,423
9301003	TV Station Advertising Time	18,415	8,354	5,222	4,839
9301012	Public Opinion Surveys	12,539	12,538	1	1
9301015	Other Corporate Comm Exp	5,132	5,132	0	0
9302000	Misc General Expenses	182,503	73,170	69,503	39,829
9302003	Corporate & Fiscal Expenses	43,787	26,597	13,759	3,431

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INCOME STATEMENT

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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Jun 2024	Kentucky Power Company - Distribution 110 Actual YTD Jun 2024	Kentucky Power Company - Generation 117 Actual YTD Jun 2024	Kentucky Power Company - Transmission 180 Actual YTD Jun 2024
9302004	Research, Develop&Demonstr Exp	557	201	258	98
9310001	Rents - Real Property	4,800	4,800	0	0
9310002	Rents - Personal Property	26,633	21,902	4,257	474
	Administration & General	**14,987,756**	**7,036,954**	**5,500,322**	**2,450,510**
4111005	Accretion Expense	391,634	7,306	384,328	0
	Accretion	**391,634**	**7,306**	**384,328**	**-**
4116000	Gain From Disposition of Plant	(7,257)	(7,257)	0	0
	Loss/(Gain) on Utility Plant	**(7,257)**	**(7,257)**	**-**	**-**
9302006	Assoc Bus Dev - Materials Sold	116,070	116,063	0	6
9302007	Assoc Business Development Exp	113,680	93,816	106	19,763
	Associated Business Development Expenses	**229,750**	**209,879**	**106**	**19,770**
	Gain on Disposition of Property	**-**	**-**	**-**	**-**
4212000	Loss on Dspsition of Property	174	0	174	0
	Loss on Disposition of Property	**174**	**-**	**174**	**-**
	Loss(Gain) of Sale of Property	**174**	**-**	**174**	**-**
4265009	Factored Cust A/R Exp - Affil	1,608,107	1,608,107	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	1,147,825	1,147,825	0	0
	Opr Exp and Factored A/R	**2,755,932**	**2,755,932**	**-**	**-**
	Water Heaters	**-**	**-**	**-**	**-**
4040007	Cloud Implement - Amort Plant	209,327	147,338	39,483	22,507
4265004	Social & Service Club Dues	24,334	5,645	18,237	452
4265007	Regulatory Expenses	2,167	981	608	578
	Expense of Non-Utility Operation	**235,828**	**153,964**	**58,327**	**23,537**
4210009	Misc Non-Op Exp - NonAssoc	16,698	16,618	29	50
	Misc NonOp Expenses - NonAssoc	**16,698**	**16,618**	**29**	**50**
4261000	Donations	791,988	783,630	4,592	3,766
	Donation Contributions	**791,988**	**783,630**	**4,592**	**3,766**
4263001	Penalties	314	211	98	5
	Provision for Penalties	**314**	**211**	**98**	**5**
4264000	Civic and Political Activity	98,471	53,436	22,992	22,046
4264001	Non-deduct Lobbying per IRS	14,223	4,883	6,467	2,873
	Civic & Political Activities	**112,695**	**58,319**	**29,459**	**24,919**
4265002	Other Deductions - Nonassoc	307,674	295,602	8,245	3,827
	Other Deductions	**307,674**	**295,602**	**8,245**	**3,827**
	Shutdown Coal Company Expenses	**-**	**-**	**-**	**-**
	All Other Operational Expenses	**4,221,129**	**4,064,276**	**100,750**	**56,105**
	Operational Expenses	**81,298,179**	**62,489,680**	**54,863,745**	**4,753,282**
5100000	Maint Supv & Engineering	912,310	0	912,310	0
5110000	Maintenance of Structures	629,143	0	629,143	0
5120000	Maintenance of Boiler Plant	6,540,283	0	6,540,283	0
5120034	BSDR O/U Recovery - Maint Cost	(5,997)	0	(5,997)	0
5120037	KY Steam Maint O/U	(313,321)	0	(313,321)	0
5130000	Maintenance of Electric Plant	2,088,417	0	2,088,417	0
5140000	Maintenance of Misc Steam Plt	817,678	0	817,678	0
5140025	Maint MiscStmPlt Environmental	(14)	0	(14)	0
	Steam Generation Maintenance	**10,668,500**	**-**	**10,668,500**	**-**

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IS8016 YTD Jun 2024 07/26/2024 13:14	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024
	Nuclear Generation Maintenance	**-**	**-**	**-**	**-**
	Hydro Generation Maintenance	**-**	**-**	**-**	**-**
	Other Generation Maintenance	**-**	**-**	**-**	**-**
5680000	Maint Supv & Engineering	14,974	908	447	13,619
5690000	Maintenance of Structures	28,417	0	0	28,417
5691000	Maint of Computer Hardware	2,466	17	(13)	2,462
5692000	Maint of Computer Software	108,511	7,803	3,974	96,734
5693000	Maint of Communication Equip	4,716	0	0	4,716
5700000	Maint of Station Equipment	298,202	1,765	0	296,437
5710000	Maintenance of Overhead Lines	2,132,645	4	9	2,132,635
5720000	Maint of Underground Lines	207	0	0	207
5730000	Maint of Misc Trnsmssion Plt	709	43	4	662
	Transmission Maintenance	**2,590,846**	**10,540**	**4,422**	**2,575,887**
5900000	Maint Supv & Engineering	9,233	9,180	17	34
5910000	Maintenance of Structures	8,119	8,095	0	24
5920000	Maint of Station Equipment	620,448	617,150	0	3,298
5930000	Maintenance of Overhead Lines	17,568,449	17,571,539	105	467
5930001	Tree and Brush Control	217,029	217,066	0	0
5940000	Maint of Underground Lines	11,676	11,682	0	0
5950000	Maint of Lne Trnf,Rglators&Dvi	11,092	11,099	0	0
5960000	Maint of Strt Lghtng & Sgnal S	5,532	5,534	0	0
5970000	Maintenance of Meters	16,978	16,961	8	22
5980000	Maint of Misc Distribution Plt	13,198	13,196	1	2
	Distribution Maintenance	**18,481,756**	**18,481,503**	**131**	**3,846**
9350000	Maintenance of General Plant	14,503	9,667	4,836	0
9350001	Maint of Structures - Owned	437,835	433,851	2,289	1,694
9350002	Maint of Structures - Leased	868	547	221	99
9350012	Maint of Data Equipment	2,283	1,708	574	0
9350013	Maint of Cmmncation Eq-Unall	631,970	606,019	26,359	0
9350015	Maint of Office Furniture & Eq	487,291	252,828	234,463	0
9350023	Site Communications Services	98	72	26	0
9350024	Maint of DA-AMI Comm Equip	869	831	11	27
	Administration & General Maintenance	**1,575,717**	**1,305,525**	**268,781**	**1,820**
	All Other Maintenance Expenses	**-**	**-**	**-**	**-**
	Maintenance Expenses	**33,316,819**	**19,797,567**	**10,941,834**	**2,581,553**
	Total Operational and Maintenance Expenses	**114,614,998**	**82,287,248**	**65,805,579**	**7,334,835**
4040001	Amort. of Plant	4,868,165	2,418,512	1,698,834	750,820
4060001	Amort of Plt Acq Adj	19,308	0	0	19,308
	DDA Amortization	**4,887,473**	**2,418,512**	**1,698,834**	**770,128**
4073000	Regulatory Debits	(0)	0	(0)	0
4073014	Regulatory Debit - BSDR	266,716	0	266,716	0
	DDA Regulatory Debits	**266,715**	**-**	**266,715**	**-**
4074000	Regulatory Credits	(4,238,861)	0	(4,238,861)	0
4074025	PPA RIDER Over/Under	259,138	0	259,138	0
	DDA Regulatory Credits	**(3,979,723)**	**-**	**(3,979,723)**	**-**
	Amortization	**1,174,466**	**2,418,512**	**(2,014,174)**	**770,128**

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INCOME STATEMENT

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Layout: IS8016

17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol IS8016 Actual YTD Jun 2024	Kentucky Power Company - Distribution 110 Actual YTD Jun 2024	Kentucky Power Company - Generation 117 Actual YTD Jun 2024	Kentucky Power Company - Transmission 180 Actual YTD Jun 2024
4030001	Depreciation Exp	52,603,354	22,254,518	18,513,706	11,835,130
4030029	Over/Undr Depr Exp Var Riders	(1,973,322)	0	(1,973,322)	0
	DDA Depreciation	**50,630,032**	**22,254,518**	**16,540,384**	**11,835,130**
	DDA STP Nuclear Decommissioning	**-**	**-**	**-**	**-**
4031001	Depr - Asset Retirement Oblig	253,923	4,721	249,202	0
	DDA Asset Retirement Obligation	**253,923**	**4,721**	**249,202**	**-**
	DDA Removal Costs	**-**	**-**	**-**	**-**
	Depreciation	**50,883,955**	**22,259,239**	**16,789,586**	**11,835,130**
	Depreciation and Amortization	**52,058,420**	**24,677,751**	**14,775,412**	**12,605,258**
	Franchise Taxes	**-**	**-**	**-**	**-**
408100624	State Gross Receipts Tax	9,896	0	9,896	0
	Revenue-kWhr Taxes	**9,896**	**-**	**9,896**	**-**
4081002	FICA	1,825,556	1,237,315	577,264	10,977
4081003	Federal Unemployment Tax	12,639	7,773	4,774	92
4081007	State Unemployment Tax	22,414	7,847	14,485	83
4081033	Fringe Benefit Loading - FICA	(737,793)	(626,822)	(99,707)	(11,264)
4081034	Fringe Benefit Loading - FUT	(3,648)	(3,116)	(470)	(62)
4081035	Fringe Benefit Loading - SUT	(4,010)	(2,427)	(1,440)	(144)
	Payroll Taxes	**1,115,158**	**620,570**	**494,907**	**(319)**
408102022	State Business Occup Taxes	(28,789)	0	(28,789)	0
408102023	State Business Occup Taxes	8,974	0	8,974	0
408102024	State Business Occup Taxes	3,684,939	0	3,684,939	0
	Capacity Taxes	**3,665,124**	**-**	**3,665,124**	**-**
408100521	Real Personal Property Taxes	832,990	778,009	7	54,974
408100522	Real Personal Property Taxes	1,560,200	0	1,560,200	0
408100523	Real Personal Property Taxes	10,429,500	5,758,398	1,075,314	3,595,788
408102924	Real-Pers Prop Tax-Cap Leases	306,606	289,614	9,780	7,212
408103624	Real Prop Tax-Cap Leases	6,804	6,804	0	0
408200523	Real Personal Property Taxes	35,798	80	34,953	765
	Property Taxes	**13,171,898**	**6,832,905**	**2,680,254**	**3,658,739**
	Regulatory Fees	**-**	**-**	**-**	**-**
408101423	Federal Excise Taxes	725	0	725	0
408101424	Federal Excise Taxes	1,146	0	1,146	0
	Production Taxes	**1,871**	**-**	**1,871**	**-**
408101923	State Sales and Use Taxes	1,530	1,530	0	0
408101924	State Sales and Use Taxes	26,467	6,670	19,797	0
	Miscellaneous Taxes	**27,997**	**8,200**	**19,797**	**-**
	Other Non-Income Taxes	**29,868**	**8,200**	**21,668**	**-**
	Taxes Other Than Income Taxes	**17,991,944**	**7,461,675**	**6,871,847**	**3,658,421**
	TOTAL OPERATING EXPENSES	**184,665,362**	**114,426,674**	**87,452,838**	**23,598,513**
	Memo: SEC Total Operating Expenses	**305,107,240**	**323,222,402**	**207,893,386**	**23,599,841**
	OPERATING INCOME	**41,212,752**	**(585,472)**	**(23,810,464)**	**65,602,842**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	91,630	4,285	87,345	0

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American Electric Power

IS8016 YTD Jun 2024 07/26/2024 13:14	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024
	Interest & Dividend NonAffiliated	**91,630**	**4,285**	**87,345**	**-**
4190005	Interest Income - Assoc CBP	157	157	0	0
	Interest & Dividend Affiliated	**157**	**157**	**-**	**-**
	Total Interest & Dividend Income	**91,787**	**4,441**	**87,345**	**-**
	Interest & Dividend Carrying Charge	**-**	**-**	**-**	**-**
	Memo: Total Interest & Dividend Income w/ Carrying	**91,787**	**4,441**	**87,345**	**-**
9260042	SERP Pension - Non-Service	(1,930)	(1,922)	(8)	0
9260043	OPEB - Non-Service	1,349,419	522,041	785,169	42,209
9260062	Pension Plan - Non-Service	2,051,804	540,309	1,546,899	(35,403)
	Other Components of Net Periodic Pension	**3,399,293**	**1,060,428**	**2,332,060**	**6,805**
4191000	Allw Oth Fnds Usd Drng Cnstr	1,201,273	299,424	272,959	628,890
	AFUDC	**1,201,273**	**299,424**	**272,959**	**628,890**
	Gain on Disposition of Equity Investments	**-**	**-**	**-**	**-**
	Interest LTD FMB	**-**	**-**	**-**	**-**
4270002	Int on LTD - Install Pur Contr	(1,527,500)	(1,527,500)	0	0
	Interest LTD IPC	**(1,527,500)**	**(1,527,500)**	**-**	**-**
4300001	Interest Exp - Assoc Non-CBP	(661,250)	(661,250)	0	0
	Interest LTD Notes Payable - Affiliated	**(661,250)**	**(661,250)**	**-**	**-**
	Interest LTD Notes Payable - NonAffiliated	**-**	**-**	**-**	**-**
	Interest LTD Debentures	**-**	**-**	**-**	**-**
4270006	Int on LTD - Sen Unsec Notes	(28,784,375)	(28,784,375)	0	0
	Interest LTD Senior Unsecured	**(28,784,375)**	**(28,784,375)**	**-**	**-**
	Interest LTD Other - Affil	**-**	**-**	**-**	**-**
4270005	Int on LTD - Other LTD	(4,830,157)	(4,830,157)	0	0
	Interest LTD Other - NonAffil	**(4,830,157)**	**(4,830,157)**	**-**	**-**
	Interest on Long-Term Debt	**(35,803,282)**	**(35,803,282)**	**-**	**-**
4300003	Int to Assoc Co - CBP	(1,831,228)	21,246,363	(29,274,530)	6,196,940
	Interest STD - Affil	**(1,831,228)**	**21,246,363**	**(29,274,530)**	**6,196,940**
4310007	Lines Of Credit	(349,977)	(156,304)	(127,050)	(66,623)
	Interest STD - NonAffil	**(349,977)**	**(156,304)**	**(127,050)**	**(66,623)**
	Interest on Short Term Debt	**(2,181,204)**	**21,090,059**	**(29,401,580)**	**6,130,317**
4280002	Amrtz Debt Dscnt&Exp-Instl Pur	(85,570)	(85,570)	0	0
4280003	Amrtz Debt Dscnt&Exp-N/P	(7,101)	(7,101)	0	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	(299,521)	(299,521)	0	0
	Amort of Debt Disc. Prem & Exp	**(392,192)**	**(392,192)**	**-**	**-**
4281004	Amrtz Loss Rcquired Debt-Dbnt	(16,825)	(16,825)	0	0
	Amort Loss on Reacquired Debt	**(16,825)**	**(16,825)**	**-**	**-**
	Amort Gain on Reacquired Debt	**-**	**-**	**-**	**-**
	Other Interest - Fuel Recovery	**-**	**-**	**-**	**-**
4310001	Other Interest Expense	5,144,066	12,671	5,124,676	6,719
4310002	Interest on Customer Deposits	(1,008,125)	(1,008,125)	0	0
9310005	Int on Regulated Fin Leases	(5,846)	0	0	0
	Other Interest - NonAffil	**4,130,094**	**(995,455)**	**5,124,676**	**6,719**
	Other Interest Expense - Affil	**-**	**-**	**-**	**-**
	Interest Rate Hedge Unrealized (Gain)/Loss	**-**	**-**	**-**	**-**

American Electric Power

INCOME STATEMENT

IS8016
YTD Jun 2024
07/26/2024 13:14

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Jun 2024	Kentucky Power Company - Distribution 110 Actual YTD Jun 2024	Kentucky Power Company - Generation 117 Actual YTD Jun 2024	Kentucky Power Company - Transmission 180 Actual YTD Jun 2024
4320000	Allw Brrwed Fnds Used Cnstr-Cr	1,725,872	449,395	388,782	887,695
	AFUDC-Borrowed Funds	**1,725,872**	**449,395**	**388,782**	**887,695**
	Total Interest Charges	**(32,537,538)**	**(15,668,299)**	**(23,888,123)**	**7,024,730**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**13,367,567**	**(14,889,478)**	**(45,006,222)**	**73,263,267**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	5,890,512	(4,709,562)	(6,181,472)	16,781,546
4092001	Inc Tax, Oth Inc&Ded-Federal	(163,911)	(128,369)	(34,414)	(1,127)
	Federal Current Income Tax	**5,726,601**	**(4,837,931)**	**(6,215,887)**	**16,780,419**
4101001	Prov Def I/T Util Op Inc-Fed	12,160,610	5,198,285	8,227,663	(1,265,339)
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(15,353,891)	(2,574,146)	(11,590,953)	(1,188,792)
	Federal Deferred Income Tax	**(3,193,282)**	**2,624,139**	**(3,363,290)**	**(2,454,131)**
	Federal Investment Tax Credits	**-**	**-**	**-**	**-**
	Federal Income Taxes	**2,533,319**	**(2,213,792)**	**(9,579,176)**	**14,326,288**
409100223	Income Taxes UOI - State	(105,969)	(1,360,172)	(1,369,218)	2,623,421
409200223	Inc Tax Oth Inc Ded - State	(41,137)	(32,217)	(8,637)	(283)
	State Current Income Tax	**(147,106)**	**(1,392,388)**	**(1,377,855)**	**2,623,138**
4111002	Prv Def I/T-Cr UtilOpInc-State	(188,630)	0	(188,630)	0
	State Deferred Income Tax	**(188,630)**	**-**	**(188,630)**	**-**
	State Investment Tax Credits	**-**	**-**	**-**	**-**
	State Income Taxes	**(335,736)**	**(1,392,388)**	**(1,566,485)**	**2,623,138**
	Local Current Income Tax	**-**	**-**	**-**	**-**
	Local Deferred Income Tax	**-**	**-**	**-**	**-**
	Local Investment Tax Credits	**-**	**-**	**-**	**-**
	Local Income Taxes	**-**	**-**	**-**	**-**
	Foreign Current Income Tax	**-**	**-**	**-**	**-**
	Foreign Deferred Income Tax	**-**	**-**	**-**	**-**
	Foreign Investment Tax Credits	**-**	**-**	**-**	**-**
	Foreign Income Taxes	**-**	**-**	**-**	**-**
	Total Income Taxes	**2,197,584**	**(3,606,181)**	**(11,145,662)**	**16,949,426**
	Equity Earnings of Subs	**-**	**-**	**-**	**-**
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	**11,169,984**	**(11,283,297)**	**(33,860,560)**	**56,313,841**
	Discontinued Operations (Net of Taxes)	**-**	**-**	**-**	**-**
	Cumulative Effect of Accounting Changes	**-**	**-**	**-**	**-**
	Extraordinary Income / (Expenses)	**-**	**-**	**-**	**-**
	NET INCOME	**11,169,984**	**(11,283,297)**	**(33,860,560)**	**56,313,841**
	Minority Interest	**-**	**-**	**-**	**-**
	Preferred Stock Dividend Subs	**-**	**-**	**-**	**-**
	Earnings to Common Shareholders	**11,169,984**	**(11,283,297)**	**(33,860,560)**	**56,313,841**
	NET INCOME (LOSS) NODE before PS	**11,169,984**	**(11,283,297)**	**(33,860,560)**	**56,313,841**
	Double Check on Net Income Node after PS	0	(0)	-	-

BS8216 YTD Jun 2024 07/26/2024 13:23	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024
	ASSETS				
	Cash and Cash Equivalents	**828,657**	**828,657**	**0**	**0**
	Other Cash Deposits	**39,370**	**17,496**	**21,256**	**618**
	Customers	14,953,552	12,249,101	677,225	2,027,226
	Accrued Unbilled Revenues	4,379,681	4,379,681	0	0
	Miscellaneous Accounts Receivable	18,028,851	3,731,394	56,283,231	17,166,558
	Allowances for Uncollectible Accounts	(349)	(258)	(5)	(87)
	Accounts Receivable	**37,361,735**	**20,359,917**	**56,960,452**	**19,193,698**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**94,095,858**	**6,658,623**	**84,293,077**	**3,144,158**
	Risk Management Contracts - Current	**11,099,455**	**2,413**	**11,097,042**	**0**
	Margin Deposits	**6,118,986**	**25,980**	**6,093,006**	**0**
	Unrecovered Fuel - Current	**6,811,867**	**0**	**6,811,867**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**2,447,042**	**2,078,671**	**304,268**	**64,103**
	TOTAL CURRENT ASSETS	**158,802,971**	**29,971,757**	**165,580,968**	**22,402,577**
	Electric Production	**1,263,205,648**	**1,281,800,131**	**1,299,241,525**	**865,268,275**
	Electric Transmission	**860,880,226**	**0**	**0**	**0**
	Electric Distribution	**1,148,776,436**	**0**	**0**	**0**
	General Property, Plant and Equipment	**174,605,156**	**83,276**	**(45,138)**	**1,119,396**
	Construction Work-in-Progress	**175,397,974**	**58,490,694**	**22,842,928**	**94,064,352**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,622,865,438**	**1,340,374,101**	**1,322,039,315**	**960,452,022**
	less: Accumulated Depreciation and Amortization	**(1,230,538,719)**	**(326,146,893)**	**(640,894,850)**	**(263,496,976)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,392,326,719**	**1,014,227,208**	**681,144,465**	**696,955,046**
	Net Regulatory Assets	**596,289,221**	**129,941,150**	**457,590,694**	**8,757,376**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**140,539**	**0**	**140,539**	**0**
	Employee Benefits and Pension Assets	**25,855,802**	**13,566,379**	**11,528,963**	**760,459**
	Other Non Current Assets	**39,437,925**	**10,893,958**	**23,553,929**	**4,990,037**
	TOTAL OTHER NON-CURRENT ASSETS	**661,723,486**	**154,401,487**	**492,814,126**	**14,507,873**
	TOTAL ASSETS	**3,212,853,176**	**1,198,600,453**	**1,339,539,559**	**733,865,496**
	LIABILITIES				
	Accounts Payable	**80,615,936**	**83,726,756**	**44,886,949**	**11,154,562**
	Advances from Affiliates	**67,816,420**	**(741,401,284)**	**1,055,100,732**	**(245,883,028)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**215,000,000**	**215,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	3,356,062	0	3,356,062	0
2440021	S/T Liability MTM Collateral	(194,835)	0	(194,835)	0
	Risk Management Liabilities - MTM	3,161,227	0	3,161,227	0
	Risk Management Liabilities	**3,161,227**	**0**	**3,161,227**	**0**
	Accrued Taxes	**40,220,405**	**4,132,082**	**(28,282,241)**	**64,370,565**

BS8216 YTD Jun 2024 07/26/2024 13:23	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024
	Memo: Property Taxes	43,972,701	22,584,304	6,573,562	14,814,835
	Accrued Interest	**11,956,039**	**11,956,039**	**0**	**0**
	Risk Management Collateral	496,705	0	496,705	0
	Utility Customer Deposits	37,667,837	37,667,837	0	0
	Deposits - Customer and Collateral	**38,164,542**	**37,667,837**	**496,705**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	126,856	48,706	78,149	0
	Obligations under Operating Leases - Current	259,714	128,378	61,367	69,970
	Tax Collections Payable	2,178,818	2,178,818	0	0
	Revenue Refunds - Accrued	502,012	0	145,673	356,339
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	513,442	450,022	58,688	4,732
	Accrued Rents	0	0	0	0
	Accrued ICP	987,163	905,741	77,023	4,400
	Accrued Vacations	2,719,243	2,429,838	266,680	22,726
	Misc Employee Benefits	1,188,118	1,001,367	185,604	1,147
	Payroll Deductions	101,860	90,175	10,421	1,264
	Severance / SEI	2,624,660	2,357,483	267,177	0
	Accrued Workers Compensation	234,282	201,235	33,047	0
2530022	Customer Advance Receipts	2,803,072	2,803,072	0	0
	Customer Advance	2,803,072	2,803,072	0	0
2420511	Control Cash Disburse Account	2,014,181	2,014,181	0	0
	Control Cash Disbursement Account	2,014,181	2,014,181	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	118,665	0	118,665	0
2300002	ARO - Current	1,442,506	0	1,442,506	0
2420088	Econ. Development Fund Curr	442,980	442,980	0	0
2420512	Unclaimed Funds	19,358	19,358	0	0
2420542	Acc Cash Franchise Req	94,920	94,920	0	0
242059224	Sales Use Tax - Leased Equip	626	626	0	0
2420643	Accrued Audit Fees	84,528	35,547	31,923	17,059
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	579,151	577,842	0	1,309
2530112	Other Deferred Credits-Curr	218,804	217,754	1,050	0
2530124	Contr In Aid of Constr Advance	104,156	104,156	0	0
	Misc Current and Accrued Liabilities	3,106,377	1,493,866	1,594,143	18,368
	Current Other and Accrued Liabilities	18,973,228	15,925,797	2,638,455	408,976
	Other Current Liabilities	**19,359,798**	**16,102,881**	**2,777,971**	**478,945**
	TOTAL CURRENT LIABILITIES	**476,294,367**	**(372,815,689)**	**1,078,141,343**	**(169,878,955)**
	Long-Term Debt - Affiliated	**25,000,000**	**25,000,000**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,060,755,231**	**1,060,755,231**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(626,500)**	**(626,500)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,060,128,731*	*1,060,128,731*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	459,532	2,095	457,437	0
2440022	L/T Liability MTM Collateral	(2,095)	(2,095)	0	0
	Long-Term Risk Management Liabilities - MTM	457,437	0	457,437	0

BS8216 YTD Jun 2024 07/26/2024 13:23	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024	YTD Jun 2024
	Long-Term Risk Management Liabilities	**457,437**	**0**	**457,437**	**0**
	Deferred Income Taxes	**473,983,364**	**166,678,577**	**218,227,967**	**89,076,821**
	Deferred Investment Tax Credits	**(0)**	**0**	**(0)**	**0**
	Regulatory Liabilities and Deferred Credits	**109,089,042**	**80,695,347**	**(3,374,261)**	**31,767,955**
	Memo - Reg Liab and Def ITC	*109,089,042*	*80,695,347*	*(3,374,261)*	*31,767,955*
	Asset Retirement Obligation	**85,667,698**	**208,370**	**85,459,328**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**7,948,492**	**11,204,307**	**(5,005,437)**	**1,749,623**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redempt	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	744,740	572,514	172,226	0
	Obligations Under Operating Leases	1,682,726	1,162,932	204,314	315,480
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	92,099	92,099	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	33,150	33,150	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	518	0	0	518
2530175	Legal Contingencies	(1,953)	(1,953)	0	0
2530185	O\U Accounting of ExpensesT	6,917	0	6,917	0
2530188	Long Term Assoc AP	4,135,307	0	0	4,135,307
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	4,258,555	31,197	6,917	4,220,441
	Total Other Deferred Credits	4,350,653	123,296	6,917	4,220,441
	Accumulated Provisions - Rate Refund	749,624	0	0	749,624
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**7,527,743**	**1,858,741**	**383,457**	**5,285,545**
	TOTAL NON-CURRENT LIABILITIES	**1,769,802,507**	**1,345,774,073**	**296,148,491**	**127,879,943**
	TOTAL LIABILITIES	**2,246,096,875**	**972,958,384**	**1,374,289,834**	**(41,999,012)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**527,602,081**	**106,025,371**	**336,884,757**	**84,691,953**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**388,704,221**	**97,212,648**	**(381,922,635)**	**673,414,208**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**966,756,302**	**225,642,069**	**(34,750,275)**	**775,864,508**
	Memo: Total Equity	966,756,302	225,642,069	(34,750,275)	775,864,508
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,212,853,176**	**1,198,600,453**	**1,339,539,559**	**733,865,496**

BS8216 YTD Jun 2023 07/10/2023 21:06	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jun 2023	YTD Jun 2023	YTD Jun 2023	YTD Jun 2023
	ASSETS				
	Cash and Cash Equivalents	**1,980,338**	**1,980,338**	**0**	**0**
	Other Cash Deposits	**55,764**	**22,325**	**32,470**	**969**
	Customers	40,179,560	39,221,173	445,017	513,369
	Accrued Unbilled Revenues	13,295,109	13,295,109	0	0
	Miscellaneous Accounts Receivable	43,053,405	7,104,886	65,736,649	14,521,770
	Allowances for Uncollectible Accounts	(635,701)	(635,644)	0	(58)
	Accounts Receivable	**95,892,373**	**58,985,525**	**66,181,666**	**15,035,081**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**82,930,439**	**7,928,261**	**71,917,732**	**3,084,447**
	Risk Management Contracts - Current	**5,570,128**	**0**	**5,570,128**	**0**
	Margin Deposits	**637,746**	**0**	**637,746**	**0**
	Unrecovered Fuel - Current	**4,021,403**	**0**	**4,021,403**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**2,068,843**	**1,787,050**	**225,549**	**56,245**
	TOTAL CURRENT ASSETS	**193,157,033**	**70,703,499**	**148,586,693**	**18,176,742**
	Electric Production	**1,241,535,413**	**1,216,316,414**	**1,280,574,217**	**818,720,250**
	Electric Transmission	**815,225,376**	**0**	**0**	**0**
	Electric Distribution	**1,088,096,633**	**0**	**0**	**0**
	General Property, Plant and Equipment	**171,980,339**	**83,276**	**24,208**	**1,119,396**
	Construction Work-in-Progress	**148,315,114**	**56,288,905**	**17,177,692**	**74,848,517**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,465,152,875**	**1,272,688,595**	**1,297,776,117**	**894,688,163**
	less: Accumulated Depreciation and Amortization	**(1,177,946,276)**	**(312,935,992)**	**(615,285,963)**	**(249,724,321)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,287,206,598**	**959,752,602**	**682,490,153**	**644,963,843**
	Net Regulatory Assets	**506,341,711**	**122,013,761**	**379,054,973**	**5,272,978**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Assets	**21,459,838**	**11,262,470**	**9,672,489**	**524,879**
	Other Non Current Assets	**25,957,038**	**7,889,009**	**14,968,735**	**3,099,294**
	TOTAL OTHER NON-CURRENT ASSETS	**553,758,588**	**141,165,240**	**403,696,198**	**8,897,151**
	TOTAL ASSETS	**3,034,122,219**	**1,171,621,341**	**1,234,773,044**	**672,037,735**
	LIABILITIES				
	Accounts Payable	**89,587,032**	**70,522,344**	**45,266,414**	**18,108,175**
	Advances from Affiliates	**144,219,975**	**(639,978,786)**	**949,557,308**	**(165,358,547)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**425,000,000**	**425,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	1,205,317	0	1,205,317	0
2440021	S/T Liability MTM Collateral	(1,022,519)	0	(1,022,519)	0
	Risk Management Liabilities - MTM	182,798	0	182,798	0
	Risk Management Liabilities	**182,798**	**0**	**182,798**	**0**

BS8216 YTD Jun 2023 07/10/2023 21:06	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
18A V2099-01-01	Layout : BS8216 Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jun 2023	YTD Jun 2023	YTD Jun 2023	YTD Jun 2023
	Accrued Taxes	**27,300,965**	**11,725,716**	(9,968,593)	**25,543,842**
	Memo: Property Taxes	25,719,800	15,150,806	5,198,174	5,370,820
	Accrued Interest	**8,228,801**	**8,228,801**	**0**	**0**
	Risk Management Collateral	209,262	0	209,262	0
	Utility Customer Deposits	40,004,159	40,004,159	0	0
	Deposits - Customer and Collateral	**40,213,421**	**40,004,159**	**209,262**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	76,551	0	76,551	0
	Obligations under Operating Leases - Current	121,801	58,725	58,919	4,157
	Tax Collections Payable	1,970,869	1,970,869	0	0
	Revenue Refunds - Accrued	117,274	0	117,274	(0)
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	492,288	432,326	56,350	3,613
	Accrued Rents	0	0	0	0
	Accrued ICP	1,297,620	1,203,807	88,893	4,919
	Accrued Vacations	2,758,500	2,394,164	342,519	21,816
	Misc Employee Benefits	1,598,831	815,735	781,587	1,509
	Payroll Deductions	122,150	95,286	25,382	1,482
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	217,693	192,601	25,092	0
2530022	Customer Advance Receipts	3,821,317	3,821,317	0	0
	Customer Advance	3,821,317	3,821,317	0	0
2420511	Control Cash Disburse Account	2,608,402	2,608,402	0	0
	Control Cash Disbursement Account	2,608,402	2,608,402	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	111,171	0	111,171	0
2300002	ARO - Current	29,797	0	29,797	0
2420088	Econ. Development Fund Curr	308,232	308,232	0	0
2420512	Unclaimed Funds	7,541	7,541	0	0
2420542	Acc Cash Franchise Req	87,182	87,182	0	0
2420643	Accrued Audit Fees	87,383	36,046	33,940	17,397
2420656	Federal Mitigation Accru (NSR)	244,045	0	244,045	0
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	406,494	405,552	0	943
2530112	Other Deferred Credits-Curr	112,768	112,768	0	0
2530124	Contr In Aid of Constr Advance	209,683	209,683	0	0
2530177	Deferred Rev-Bonus Lease Curr	17,076	0	17,076	0
	Misc Current and Accrued Liabilities	1,622,056	1,167,688	436,028	18,340
	Current Other and Accrued Liabilities	16,627,000	14,702,195	1,873,126	51,680
	Other Current Liabilities	**16,825,352**	**14,760,920**	**2,008,595**	**55,837**
	TOTAL CURRENT LIABILITIES	**751,558,343**	(69,736,847)	**987,255,785**	(121,650,694)
	Long-Term Debt - Affiliated	**25,000,000**	**25,000,000**	**0**	**0**
	Long-Term Debt - Non Affiliated	**753,363,918**	**753,363,918**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**0**	**0**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*753,363,918*	*753,363,918*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	201	0	201	0

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BS8216 YTD Jun 2023 07/10/2023 21:06	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jun 2023	YTD Jun 2023	YTD Jun 2023	YTD Jun 2023
2440022	L/T Liability MTM Collateral	(201)	0	(201)	0
	Long-Term Risk Management Liabilities - MTM	(0)	0	(0)	0
	Long-Term Risk Management Liabilities	**(0)**	**0**	**(0)**	**0**
	Deferred Income Taxes	**457,475,952**	**153,281,194**	**217,020,045**	**87,174,713**
	Deferred Investment Tax Credits	**(0)**	**0**	**(0)**	**0**
	Regulatory Liabilities and Deferred Credits	**88,759,970**	**60,888,095**	**2,031,725**	**25,840,150**
	Memo - Reg Liab and Def ITC	*88,759,969*	*60,888,095*	*2,031,725*	*25,840,150*
	Asset Retirement Obligation	**18,502,832**	**194,113**	**18,308,719**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**7,967,329**	**10,707,132**	**(4,290,184)**	**1,550,380**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redemption	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	250,376	0	250,376	0
	Obligations Under Operating Leases	439,847	203,299	236,548	0
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	98,683	98,683	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	46,791	46,791	0	0
2530101	MACSS Unidentified EDI Cash	1,375	1,375	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	1,406	0	0	1,406
2530185	O\U Accounting of ExpensesT	1,095	0	1,095	0
2530188	Long Term Assoc AP	2,203,456	0	611,274	1,592,182
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	2,338,738	48,166	612,369	1,678,204
	Total Other Deferred Credits	2,437,422	146,849	612,369	1,678,204
	Accumulated Provisions - Rate Refund	1,583,662	0	37,950	1,545,712
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**4,711,307**	**350,148**	**1,137,243**	**3,223,916**
	TOTAL NON-CURRENT LIABILITIES	**1,355,781,307**	**1,003,784,600**	**234,207,549**	**117,789,158**
	TOTAL LIABILITIES	**2,107,339,650**	**934,047,753**	**1,221,463,333**	**(3,861,536)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,235,187**	**106,025,371**	**336,070,072**	**84,139,743**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**350,097,382**	**109,144,167**	**(333,047,964)**	**574,001,180**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**926,782,569**	**237,573,587**	**13,309,711**	**675,899,270**
	Memo: Total Equity	926,782,569	237,573,587	13,309,711	675,899,270
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,034,122,219**	**1,171,621,341**	**1,234,773,044**	**672,037,735**

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KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - June, 2024

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		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,276,923,610.03	8,179,373.56	(8,322,946.06)	0.00	0.00	1,276,780,037.53
101/106	CLOUD GENERATION	381,874.02	30,844.20	0.00	0.00	0.00	412,718.22
	TOTAL PRODUCTION	**1,277,305,484.05**	**8,210,217.76**	**(8,322,946.06)**	**0.00**	**0.00**	**1,277,192,755.75**
101/106	TRANSMISSION	842,600,699.05	24,160,909.95	(1,493,334.44)	0.00	0.00	865,268,274.56
101/106	CLOUD TRANSMISSION	201,394.70	52,476.90	0.00	0.00	0.00	253,871.60
101/106	DISTRIBUTION	1,249,889,192.92	38,108,078.74	(7,645,844.61)	0.00	0.00	1,280,351,427.05
101/106	CLOUD DISTRIBUTION	1,618,196.01	231,977.79	0.00	0.00	0.00	1,850,173.80
	TOTAL (ACCOUNTS 101 & 106)	**3,371,614,966.73**	**70,763,661.14**	**(17,462,125.11)**	**0.00**	**0.00**	**3,424,916,502.76**
1011001/12	CAPITAL LEASES	1,080,445.85	0.00	0.00	143,751.65	0.00	1,224,197.50
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**3,372,695,412.58**	**70,763,661.14**	**(17,462,125.11)**	**143,751.65**	**0.00**	**3,426,140,700.26**
1050001	PLANT HELD FOR FUTURE USE	801,671.21	0.00	0.00	0.00	0.00	801,671.21
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEGINNING BALANCE	159,612,262.17					
107000X	ADDITIONS		85,389,724.20				
107000X	TRANSFERS		(69,604,012.86)				
107000X	ENDING BALANCE		15,785,711.34				175,397,973.51
107000X	**CLOUD CONSTRUCTION WIP:**						
107000X	BEGINNING BALANCE	1,540,647.27					
107000X	ADDITIONS		565,389.91				
107000X	TRANSFERS		(315,298.89)				
107000X	ENDING BALANCE		250,091.02				1,790,738.29
	TOTAL ELECTRIC UTILITY PLANT	**3,534,649,993.23**	**86,799,463.50**	**(17,462,125.11)**	**143,751.65**	**0.00**	**3,604,131,083.27**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	571,711.48	0.00	(69,345.76)	0.00	0.00	502,365.72
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1210003	NONUTILITY PROPERTY-WIP						
	BEGINNING BALANCE	0.00					
	ADDITIONS		0.00				
	TRANSFERS		0.00				
	ENDING BALANCE		0.00				0.00
1210016	NONUTILITY PROPERTY-CCNC	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	655,168.37	0.00	0.00	0.00	0.00	655,168.37
	TOTAL NONUTILITY PLANT	**1,226,879.85**	**0.00**	**(69,345.76)**	**0.00**	**0.00**	**1,157,534.09**

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KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - June, 2024

Final

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		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
.	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	623,339,018.27	18,781,276.84	(6,660,191.19)	(3,837,216.09)	(4,118,311.49)	627,504,576.34
1080001/11	TRANSMISSION	284,929,166.47	11,835,129.99	(979,767.51)	(49,681.83)	0.00	295,734,847.12
1080001/11	DISTRIBUTION	376,851,080.91	22,259,653.30	(5,904,374.07)	(2,308,749.51)	(152,964.97)	390,744,645.66
1080013	PRODUCTION	(4,098,119.71)	0.00	0.00	0.00	4,098,119.71	0.00
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(151,934.59)	0.00	0.00	0.00	151,934.59	0.00
	RETIREMENT WORK IN PROGRESS	(13,358,319.70)	0.00	0.00	(5,801,369.17)	6,195,647.43	(12,964,041.44)
	TOTAL (108X accounts)	**1,267,510,891.66**	**52,876,060.13**	**(13,544,332.77)**	**(11,997,016.60)**	**6,174,425.27**	**1,301,020,027.69**
	NUCLEAR					0.00	
1110001	PRODUCTION	12,296,619.11	1,790,124.66	(1,662,754.87)	0.00	0.00	12,423,988.90
1110007	CLOUD IMPLEMENT COST PRODUCTI	103,001.61	39,482.51	0.00	0.00	0.00	142,484.12
1110001	TRANSMISSION	4,150,582.38	790,089.61	(513,566.93)	0.00	0.00	4,427,105.06
1110007	CLOUD IMPLEMENT COST TRANSMIS	36,477.38	22,507.39	0.00	0.00	0.00	58,984.77
1110001	DISTRIBUTION	14,363,824.54	2,475,431.78	(1,741,470.54)	0.00	0.00	15,097,785.78
1110007	CLOUD IMPLEMENT COST DISTRIBUT	417,883.25	147,337.58	0.00	0.00	0.00	565,220.83
	TOTAL (111X accounts)	**31,368,388.27**	**5,264,973.53**	**(3,917,792.34)**	**0.00**	**0.00**	**32,715,569.46**
1011006	CAPITAL LEASES	291,805.66	0.00	0.00	0.00	59,750.86	351,556.52
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**1,299,171,085.59**	**58,141,033.66**	**(17,462,125.11)**	**(11,997,016.60)**	**6,234,176.13**	**1,334,087,153.67**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	172,262.12	3,334.89	(69,345.76)	69,987.88	0.00	176,239.13
1220002	Depr&Amrt of Nonutl Prop-Leasd	0.00	0.00	0.00	0.00	0.00	0.00
1220003	Depr&Amrt of Nonutl Prop-WIP	69,987.88	0.00	0.00	0.00	(69,987.88)	0.00
1220004	Depletion - Owned	0.00	0.00	0.00	0.00	0.00	0.00
1240027	Other Property - RWIP	35,121.36	0.00	0.00	0.00	0.00	35,121.36
1240028	Other Property - Retirement	(46,947.27)	0.00	0.00	0.00	0.00	(46,947.27)
	TOTAL NONUTILITY PLANT	**230,424.09**	**3,334.89**	**(69,345.76)**	**69,987.88**	**(69,987.88)**	**164,413.22**

U.S. Department of Energy
Energy Information Administration
Form EIA-826

Monthly Electric Utility Sales and Revenue Report with State Distributions – 2024

Form Approval
OMB NO.1905-0129
(Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**

Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650.

Utility Name: Kentucky Power Company **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan___ Feb___ Mar___ Apr___ May___ Jun_X_ Jul___ Aug___ Sep___ Oct___ Nov___ Dec__ , 2024

Contact Person: Sandra Vargo	**Phone number: 614-716-2671**
Email: slvargo@aep.com	**Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	18,864	14,833	14,196	-	47,893
	b. Megwatthours	126,450	117,571	178,045	-	422,066
	c. Number of consumers	130,581	30,650	964	-	162,195
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					

Note:

KPSC Case No. 2025-00257
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August 29th, 2024

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed July 2024 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:	
1-12	Income Statement
1-3	Details of Operating Revenues
5-10	Operating Expenses – Functional Expenses
12	Detail Statement of Taxes
Balance Sheet:	
13	Balance Sheet – Assets & Other Debits
13-15	Balance Sheet – Liabilities & Other Credits
14-15	Deferred Credits
15	Statement of Retained Earnings
Utility Property:	
16-17	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Digitally signed by Brian J. Frantz
DN: cn=Brian J. Frantz, c=US, o=AEP, ou=Corporate Accounting, email=bjfrantz@aep.com
Reason: I have reviewed this document
Date: 2024.08.29 12:46:40 -04'00'

Brian J Frantz
Director - Corporate Accounting

American Electric Power

INCOME STATEMENT

IS8016
YTD Jul 2024
08/08/2024 00:02

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Jul 2024	Kentucky Power Company - Distribution 110 Actual YTD Jul 2024	Kentucky Power Company - Generation 117 Actual YTD Jul 2024	Kentucky Power Company - Transmission 180 Actual YTD Jul 2024
		REVENUES				
4400001		Residential Sales-W/Space Htg	84,585,920	84,585,920	0	0
4400002		Residential Sales-W/O Space Ht	37,823,274	38,588,527	(765,253)	0
4400005		Residential Fuel Rev	42,991,802	42,991,802	0	0
	A	**Revenue - Residential Sales**	**165,400,995**	**166,166,248**	**(765,253)**	**-**
4420001		Commercial Sales	57,420,054	58,024,209	(604,155)	0
4420006		Sales to Pub Auth - Schools	9,053,171	9,053,171	0	0
4420007		Sales to Pub Auth - Ex Schools	11,428,004	11,428,004	0	0
4420013		Commercial Fuel Rev	31,653,021	31,653,021	0	0
	A	**Revenue - Commercial Sales**	**109,554,249**	**110,158,404**	**(604,155)**	**-**
	B	**Revenue - Industrial Sales - Affiliated**	**-**	**-**	**-**	**-**
4420002		Industrial Sales (Excl Mines)	41,761,943	42,651,629	(889,686)	0
4420004		Ind Sales-NonAffil(Incl Mines)	10,666,467	10,666,467	0	0
4420016		Industrial Fuel Rev	43,676,231	43,676,231	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**96,104,641**	**96,994,327**	**(889,686)**	**-**
		Revenue - Industrial Sales	**96,104,641**	**96,994,327**	**(889,686)**	**-**
	A	**Revenue - Gas Products Sales**	**-**	**-**	**-**	**-**
	A	**Revenue - Gas Transportation & Storage Sales**	**-**	**-**	**-**	**-**
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	**-**	**-**	**-**	**-**
4440000		Public Street/Highway Lighting	1,046,386	1,049,928	(3,542)	0
4440002		Public St & Hwy Light Fuel Rev	186,009	186,009	0	0
	A	**Revenue - Other Retail Sales**	**1,232,395**	**1,235,937**	**(3,542)**	**-**
	B	**Revenue - Other Retail Sales - Affiliated**	**-**	**-**	**-**	**-**
		Revenue - Retail Sales	**372,292,280**	**374,554,916**	**(2,262,636)**	**-**
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	48,317,649
4561033		PJM NITS Revenue - Affiliated	42,907,889	0	0	42,907,889
4561034		PJM TO Adm. Serv Rev - Aff	147,703	0	0	147,703
4561035		PJM Affiliated Trans NITS Cost	(35,366,726)	0	(35,366,726)	0
4561036		PJM Affiliated Trans TO Cost	(98,292)	0	(98,292)	0
4561059		Affil PJM Trans Enhancmnt Rev	911,770	0	0	911,770
4561060		Affil PJM Trans Enhancmnt Cost	(751,524)	0	(751,524)	0
4561062		PROVISION RTO Cost - Affi	365,856	0	365,856	0
4561063		PROVISION RTO Rev Affiliated	2,266,649	0	0	2,266,649
	B	**Revenue - Transmission-Affiliated**	**10,383,324**	**-**	**(35,850,687)**	**94,551,660**
4470150		Transm. Rev.-Dedic. Whlsl/Muni	107,452	0	(1,500,647)	1,608,099
4470206		PJM Trans loss credits-OSS	59,126	0	59,126	0
4470209		PJM transm loss charges-OSS	(144,514)	0	(144,514)	0
4561005		PJM Point to Point Trans Svc	1,376,476	0	1,376,476	0
4561006		PJM Trans Owner Admin Rev	52,575	0	0	52,575
4561007		PJM Network Integ Trans Svc	6,443,824	0	0	6,443,824
4561019		Oth Elec Rev Trans Non Affil	31,379	0	0	31,379
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	2,535	0	0	2,535
4561029		PJM NITS Revenue Whsl Cus-NAff	1,441,290	0	0	1,441,290
4561030		PJM TO Serv Rev Whls Cus-NAff	5,436	0	0	5,436
4561045		PJM Non-Aff Gen IPP Rev	1,911	0	0	1,911
4561058		NonAffil PJM Trans Enhncmt Rev	1,002,213	0	0	1,002,213
4561061		NAff PJM RTEP Rev for Whsl-FR	30,627	0	0	30,627
4561064		PROVISION RTO Rev WhslCus-NAf	76,209	0	0	76,209
4561065		PROVISION RTO Rev - NonAff	334,286	0	(1)	334,287

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American Electric Power

INCOME STATEMENT

IS8016 YTD Jul 2024 08/08/2024 00:02			Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
		Layout: IS8016				
17A V2099-01-01		Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024
	A	**Revenue - Transmission-NonAffiliated**	**10,820,824**	**-**	**(209,560)**	**11,030,384**
		Revenue - Transmission	**21,204,148**	**-**	**(36,060,247)**	**105,582,044**
	B	**Revenue - Resale-Affiliated**	**-**	**-**	**-**	**-**
4470010		Sales for Resale-Bookout Purch	(19)	0	(19)	0
4470027		Whsal/Muni/Pb Ath Fuel Rev	1,507,979	0	1,507,979	0
4470033		Whsal/Muni/Pub Auth Base Rev	973,176	0	973,176	0
4470082		Financial Electric Realized	(3,298)	0	(3,298)	0
4470089		PJM Energy Sales Margin	734,467	0	734,467	0
4470098		PJM Oper.Reserve Rev-OSS	(27,068)	0	(27,068)	0
4470099		Capacity Cr. Net Sales	(20,520)	0	(20,520)	0
4470100		PJM FTR Revenue-OSS	139,766	0	139,766	0
4470103		PJM Energy Sales Cost	8,037,295	0	8,037,295	0
4470110		PJM TO Admin. Exp.-NonAff.	4	0	4	0
4470115		PJM Meter Corrections-OSS	(8,789)	0	(8,789)	0
4470116		PJM Meter Corrections-LSE	(196,551)	0	(196,551)	0
4470126		PJM Incremental Imp Cong-OSS	(289,677)	0	(289,677)	0
4470175		OSS Sharing Reclass - Retail	3,302,211	0	3,302,211	0
4470176		OSS Sharing Reclass-Reduction	(3,302,211)	0	(3,302,211)	0
4470215		PJM 30m Suppl Reserve CH OSS	2,731	0	2,731	0
4470220		PJM Regulation - OSS	2,865,799	0	2,865,799	0
4470221		PJM Spinning Reserve - OSS	32,941	0	32,941	0
5550080		PJM Hourly Net Purch.-FERC	(4,353,290)	0	(4,353,290)	0
	A	**Revenue - Resale-NonAffiliated**	**9,394,945**	**-**	**9,394,945**	**-**
	A	**Revenue - Resale-Realized**	**-**	**-**	**-**	**-**
	A	**Revenue - Resale-Risk Mgmt MTM**	**-**	**-**	**-**	**-**
	A	**Revenue - Resale-Risk Mgmt Activities**	**-**	**-**	**-**	**-**
		Revenue - Sales for Resale	**9,394,945**	**-**	**9,394,945**	**-**
4470074		Sale for Resale-Aff-Trnf Price	0	0	244,623,132	0
4540001		Rent From Elect Property - Af	674,434	535,526	0	287,313
	B	**Revenue - Other Ele-Affilliated**	**674,434**	**535,526**	**244,623,132**	**287,313**
4500000		Forfeited Discounts	488,130	488,130	0	0
4510001		Misc Service Rev - Nonaffil	87,021	86,503	0	518
4540002		Rent From Elect Property-NAC	2,194,977	1,725	2,173,977	19,275
4540005		Rent from Elec Prop-Pole Attch	2,916,861	2,912,366	0	4,495
4560007		Oth Elect Rev - DSM Program	318,852	318,852	0	0
5010040		Gas Procuremnt Sales Net	(1,140,697)	0	(1,140,697)	0
		Revenue - Other Ele-NonAffilliated	**4,865,143**	**3,807,575**	**1,033,280**	**24,288**
		Revenue - Gas	**-**	**-**	**-**	**-**
4118002		Comp. Allow Gains Title IV SO2	14	14	0	0
		Gain/(Loss) on Allowances	**14**	**14**	**-**	**-**
	A	**Revenue - Other Ele-NonAffilliated**	**4,865,158**	**3,807,590**	**1,033,280**	**24,288**
		Revenue - Other Opr Electric	**5,539,592**	**4,343,115**	**245,656,412**	**311,602**
	D	**Revenue Merchandising & Contract Work**	**-**	**-**	**-**	**-**
	C	**Revenues Non-Utility Operations - Affiliated**	**-**	**-**	**-**	**-**
4170004		Rev from Non-Util Oper NonAfil	194,481	194,481	0	0
	D	**Revenues Non-Utility Operations - NonAffiliated**	**194,481**	**194,481**	**-**	**-**
		Revenues from Non-Utility Operations	**194,481**	**194,481**	**-**	**-**
	C	**Non-Operating Rental Income - Affiliated**	**-**	**-**	**-**	**-**

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American Electric Power

INCOME STATEMENT

IS8016
YTD Jul 2024
08/08/2024 00:02

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Jul 2024	Kentucky Power Company - Distribution 110 Actual YTD Jul 2024	Kentucky Power Company - Generation 117 Actual YTD Jul 2024	Kentucky Power Company - Transmission 180 Actual YTD Jul 2024
4180001		Non-Operatng Rental Income	400	400	0	0
4180005		Non-Opratng Rntal Inc-Depr	(3,891)	0	0	(3,891)
	D	**Non-Operating Rental Income - NonAffiliated**	**(3,491)**	**400**	**-**	**(3,891)**
		Non-Operating Rental Income	**(3,491)**	**400**	**-**	**(3,891)**
	C	**Non-Operating Misc Income -Affiliated**	**-**	**-**	**-**	**-**
4210002		Misc Non-Op Inc-NonAsc-Rents	1,100	335	567	198
4210007		Misc Non-Op Inc - NonAsc - Oth	6,524	767	5,757	0
	D	**Non-Operating Misc Income - NonAffiliated**	**7,624**	**1,102**	**6,325**	**198**
		Non-Operating Misc Income	**7,624**	**1,102**	**6,325**	**198**
4540004		Rent From Elect Prop-ABD-Nonaf	1,674	1,674	0	0
4560015		Other Electric Revenues - ABD	347,718	344,718	0	3,000
	D	**Associated Business Development Income**	**349,392**	**346,392**	**-**	**3,000**
		Revenue - Other Opr - Other	**548,007**	**542,375**	**6,325**	**(693)**
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	***-***	***-***	***-***	***-***
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***548,007***	***542,375***	***6,325***	***(693)***
		Revenue - Other Operating	**6,087,598**	**4,885,490**	**245,662,736**	**310,909**
4491002		Prov Rate Refund-Nonaffiliated	(52,083)	0	0	(52,083)
4491003		Prov Rate Refund - Retail	(11,165)	0	0	(11,165)
	A	**Provision for Rate Refund - NonAffiliated**	**(63,248)**	**-**	**-**	**(63,248)**
4491004		Prov Rate Refund - Affiliated	(326,147)	0	0	(326,147)
	B	**Provision for Rate Refund - Affiliated**	**(326,147)**	**-**	**-**	**(326,147)**
		Provision for Rate Refund	**(389,395)**	**-**	**-**	**(389,395)**
	A	**Revenue - Power Sales**	**-**	**-**	**-**	**-**
		TOTAL OPERATING REVENUES	**408,589,577**	**379,440,406**	**216,734,799**	**105,503,558**
=(A)		*Memo: G/T/D Revenue*	*397,309,959*	*378,362,506*	*7,956,029*	*10,991,424*
=(B)		*Memo: Other Affiliated Revenue*	*10,731,611*	*535,526*	*208,772,445*	*94,512,826*
=(C)		*Memo: Revenue-Oth Opr-Oth Al*	-	-	-	-
=(D)		*Memo: Revenue-Oth Opr-Oth N*	*548,007*	*542,375*	*6,325*	*(693)*
		Memo: Total Operating Revenues	*408,589,577*	*379,440,406*	*216,734,799*	*105,503,558*
=(E)=(B)+(C)		*Memo: Affiliated Revenue*	***10,731,611***	***535,526***	***208,772,445***	***94,512,826***
=(F)=(D)+(A)		*Memo: Non-Affiliated Revenue*	***397,857,966***	***378,904,881***	***7,962,354***	***10,990,732***
		Memo: Total Operating Revenues	***408,589,577***	***379,440,406***	***216,734,799***	***105,503,558***
		FUEL EXPENSES				
5010000		Fuel	3,549,213	2	3,549,209	1
5010001		Fuel Consumed	48,686,221	0	48,686,221	0
5010003		Fuel - Procure Unload & Handle	1,943,695	0	1,943,695	0
5010012		Ash Sales Proceeds	10,674	0	10,674	0
5010013		Fuel Survey Activity	49,281	0	49,281	0
5010019		Fuel Oil Consumed	2,161,388	0	2,161,388	0
5010020		Nat Gas Consumed Steam	20,263,773	0	20,263,773	0
5010021		Transp Gas Consumed Steam	575,078	0	575,078	0
5010027		Gypsum handling/disposal costs	792,956	0	792,956	0
5010028		Gypsum Sales Proceeds	(790,066)	0	(790,066)	0
5010034		Gas Transp Res Fees-Steam	3,696,767	0	3,696,767	0
		Fuel Expense Total	**80,938,980**	**2**	**80,938,976**	**1**
5010005		Fuel - Deferred	475,218	0	475,218	0
		Deferred Fuel Expense	**475,218**	**-**	**475,218**	**-**

KPSC Case No. 2025-00257
Application - Section II
Filing Requirements
Exhibit R
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American Electric Power

IS8016 YTD Jul 2024 08/08/2024 00:02	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024
	Over Under Fuel Expense				
	Fuel for Electric Generation	**81,414,198**	**2**	**81,414,194**	**1**
	Fuel from Affiliates for Electric Generation	**-**	**-**	**-**	**-**
5090000	Allow Consum Title IV SO2	19,930	0	19,930	0
5090009	Allow Consumpt CSAPR SO2	96	0	96	0
5570009	Other Pwr Exp- REC's - RETAIL	446	0	446	0
	Allowances - Consumption	**20,472**	**-**	**20,472**	**-**
5020002	Urea Expense	773,607	0	773,607	0
5020004	Lime-Related Expenses	1,181,701	0	1,181,701	0
	Emissions Control - Chemicals	**1,955,308**	**-**	**1,955,308**	**-**
	Total Fuel for Electric Generation	**83,389,977**	**2**	**83,389,973**	**1**
	Memo: NonAff Fuel/Allow/Emissions	***83,389,977***	***2***	***83,389,973***	***1***
5550004	Purchased Power-Pool Capacity	373,078	0	373,078	0
5550029	Purch Power-Assoc-Trnsfr Price	0	244,623,132	0	0
	Purchased Electricity from AEP - Affiliates	**373,078**	**244,623,132**	**373,078**	**-**
5550001	Purch Pwr-NonTrading-Nonassoc	48,720,416	0	48,720,416	0
5550023	Purch Power Capacity -NA	411,515	0	411,515	0
5550039	PJM Inadvertent Mtr Res-OSS	4,347	0	4,347	0
5550040	PJM Inadvertent Mtr Res-LSE	43,693	0	43,693	0
5550074	PJM Reactive-Charge	2,125,630	0	2,125,630	0
5550075	PJM Reactive-Credit	(837,011)	0	(837,011)	0
5550076	PJM Black Start-Charge	620,248	0	620,248	0
5550078	PJM Regulation-Charge	368,860	0	368,860	0
5550079	PJM Regulation-Credit	(10,844)	0	(10,844)	0
5550083	PJM Sync & Non Sync-Charge	269,259	0	269,259	0
5550084	PJM Sync & Non Sync-Credit	(27,529)	0	(27,529)	0
5550123	PJM OpRes-LSE-Charge	892,987	0	891,661	1,326
5550124	PJM Implicit Congestion-LSE	4,142,487	0	4,142,487	0
5550132	PJM FTR Revenue-LSE	(4,508,527)	0	(4,508,527)	0
5550137	PJM OpRes-LSE-Credit	(36,069)	0	(36,069)	0
5550153	PurchPower-Rockport Def-NonAff	152,680	0	152,680	0
5550326	PJM Transm Loss Charges - LSE	3,452,463	0	3,452,463	0
5550327	PJM Transm Loss Credits-LSE	(1,364,164)	0	(1,364,164)	0
5550328	PJM FC Penalty Credit	(2,453)	0	(2,453)	0
	Purchased Electricity for Resale - NonAffiliated	**54,417,986**	**-**	**54,416,660**	**1,326**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**
8140000	Underground Storage Expenses	1,637	0	1,637	0
	Purchased Gas for Resale - NonAffiliated	**1,637**	**-**	**1,637**	**-**
	Total Purchased Power	**54,792,702**	**244,623,132**	**54,791,376**	**1,326**
	GROSS MARGIN	**270,406,898**	**134,817,272**	**78,553,450**	**105,502,230**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	2,741,202	(19,688)	2,755,530	5,361
5020000	Steam Expenses	906,231	0	906,231	0
5050000	Electric Expenses	24,964	0	24,964	0
5060000	Misc Steam Power Expenses	3,987,434	61,216	3,921,646	4,572
5060002	Misc Steam Power Exp-Assoc	30,879	0	30,879	0
5060004	NSR Settlement Expense	10,130	0	10,130	0
5060011	BSRR O/U Recovery-Oper Costs	367	0	367	0

American Electric Power

IS8016 YTD Jul 2024 08/08/2024 00:02	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024
	Steam Generation Op Exp	**7,701,208**	**41,528**	**7,649,747**	**9,933**
	Nuclear Generation Op Exp	**-**	**-**	**-**	**-**
	Hydro Generation Op Exp	**-**	**-**	**-**	**-**
5560000	Sys Control & Load Dispatching	36,672	0	36,672	0
5570000	Other Expenses	513,680	0	513,680	0
5570007	Other Pwr Exp - Wholesale RECs	245	245	0	0
5570010	OH Auction Exp - Incremental	6	0	6	0
5757000	PJM Admin-MAM&SC- OSS	43,947	0	43,947	0
5757001	PJM Admin-MAM&SC- Internal	849,641	0	849,641	0
	Other Generation Op Exp	**1,444,190**	**245**	**1,443,945**	**-**
5600000	Oper Supervision & Engineering	1,269,279	35,908	14,179	1,219,192
5612000	Load Dispatch-Mntr&Op TransSys	223,045	2,513	335	220,197
5614000	PJM Admin-SSC&DS-OSS	45,995	0	45,995	0
5614001	PJM Admin-SSC&DS-Internal	796,929	0	796,929	0
5614009	GreenHat Settlement	3,535	0	3,535	0
5615000	Reliability,Plng&Stds Develop	39,721	926	127	38,669
5618000	PJM Admin-RP&SDS-OSS	14,700	0	14,700	0
5618001	PJM Admin-RP&SDS- Internal	269,969	0	269,969	0
5620001	Station Expenses - Nonassoc	128,817	(0)	(1)	128,819
5630000	Overhead Line Expenses	14,246	2	0	14,243
5640000	Underground Line Expenses	16	0	0	16
5650002	Transmssn Elec by Others-NAC	56,321	0	56,321	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	48,317,649	0	0
5650012	PJM Trans Enhancement Charge	1,208,799	0	1,208,799	0
5650015	PJM TO Serv Exp - Aff	98,724	0	98,724	0
5650016	PJM NITS Expense - Affiliated	43,443,139	0	43,443,139	0
5650019	Affil PJM Trans Enhncement Exp	3,207,744	0	3,207,744	0
5650020	PROVISION RTO Affl Expense	(3,065,098)	0	(3,065,098)	0
5650021	PJM NITS Expense - Non-Affilia	505,577	0	505,577	0
5650023	Amort of PROVISION RTO Expense	31,973	0	31,973	0
5660000	Misc Transmission Expenses	850,505	117,564	2,175	730,766
5660009	PJM OATT LSE Over-Under Adjust	1,248,885	0	1,248,885	0
5660011	Misc Transm Exp - Affiliate	2,109	0	0	2,109
5670002	Rents - Associated	0	0	0	148,405
	Transmission Op Exp	**50,394,929**	**48,474,561**	**47,884,007**	**2,502,417**
5800000	Oper Supervision & Engineering	786,981	785,065	461	1,491
5820000	Station Expenses	292,763	291,146	18	1,600
5830000	Overhead Line Expenses	172,328	172,466	(1)	7
5840000	Underground Line Expenses	198,195	198,178	95	(77)
5850000	Street Lighting & Signal Sys E	21,978	21,981	0	0
5860000	Meter Expenses	859,282	859,980	40	60
5870000	Customer Installations Exp	126,621	126,717	1	(55)
5880000	Miscellaneous Distribution Exp	4,473,711	4,468,618	468	4,985
5890001	Rents - Nonassociated	522,574	522,574	0	0
5890002	Rents - Associated	56,006	56,006	0	0
	Distribution Op Exp	**7,510,438**	**7,502,730**	**1,082**	**8,010**
9010000	Supervision - Customer Accts	4,911	4,886	6	20
9020000	Meter Reading Expenses	21,963	21,963	0	0
9020002	Meter Reading - Regular	180,661	180,719	0	0

American Electric Power

IS8016 YTD Jul 2024 08/08/2024 00:02	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024
9020003	Meter Reading - Large Power	19,019	19,019	0	0
9030000	Cust Records & Collection Exp	178,181	176,054	(1)	2,128
9030001	Customer Orders & Inquiries	1,763,836	1,763,514	92	259
9030002	Manual Billing	6,856	6,825	16	15
9030003	Postage - Customer Bills	351,065	351,065	0	0
9030004	Cashiering	31,729	31,729	0	0
9030005	Collection Agents Fees & Exp	1,582	1,582	0	0
9030006	Credit & Oth Collection Activi	390,262	390,522	0	0
9030007	Collectors	197,788	197,788	0	0
9030009	Data Processing	20,707	20,695	5	5
9040007	Uncoll Accts - Misc Receivable	8,749	8,711	7	31
9050000	Misc Customer Accounts Exp	12,419	12,419	0	0
9070000	Supervision - Customer Service	34,050	34,063	(2)	(9)
9080000	Customer Assistance Expenses	763,058	763,085	0	0
9080009	Cust Assistance Expense - DSM	337,739	337,733	0	8
9100000	Misc Cust Svc&Informational Ex	3,779	1,763	1,031	985
	Customer Service and Information Op Exp	**4,328,352**	**4,324,134**	**1,155**	**3,442**
9120000	Demonstrating & Selling Exp	5,933	5,931	1	2
9120003	Demo & Selling Exp - Area Dev	28	28	0	0
9130001	Advertising Exp - Residential	80	72	7	1
	Sales Expenses	**6,041**	**6,030**	**8**	**2**
	Memo: Insurance (9240 9250)	**1,884,423**	**1,027,436**	**692,656**	**164,331**
9200000	Administrative & Gen Salaries	7,514,297	3,528,495	2,802,159	1,183,652
9210001	Off Supl & Exp - Nonassociated	382,881	258,106	84,943	39,861
9210003	Office Supplies & Exp - Trnsf	161	71	62	28
9210020	EMP RECOG - Over 100 Dollars	2	2	1	0
9210021	EMP TRAVEL - Airfare	37	18	14	4
9210022	MEALS & ENT-100 Pct DEDUCTIBLE	71	23	37	11
9210023	EMP TRAVEL-MILEAGE	483	245	149	89
9210024	EMP TRAVEL-PARKING	10	6	4	1
9210025	MEALS & ENT-50 Pct DEDUCTIBLE	38	23	13	2
9210026	EMP TRAVEL-CAR RENTAL	20	10	7	2
9210027	EMP TRAVEL-TAXI AND SHUTTLE	3	1	1	0
9210028	EMP TRAVEL-HOTEL & LODGING	489	201	216	72
9210030	EMP TRAVEL-OTHER	82	65	16	1
9210031	SAFETY EQUIPMENT AND SUPPLIES	7	2	4	1
9210032	FUEL	5	3	2	0
9210033	FOOD SERVICE-CATERING	5	2	2	1
9210034	In-House Training & Seminars	52	0	0	52
9210037	OEM/TECHNICAL TRAINING	23	0	0	23
9210040	DUES-BUSINESS/PROFESSIONAL	3	1	1	1
9210041	VEHICLE-LICENSE FEES	3	1	1	1
9220000	Administrative Exp Trnsf - Cr	(120,502)	(120,502)	(0)	(0)
9220001	Admin Exp Trnsf to Cnstrction	(286,161)	(286,161)	0	0
9220004	Admin Exp Trnsf to ABD	8	8	0	0
9220005	Overhead Loadings	(399,255)	(265,414)	(115,055)	(18,786)
9230001	Outside Svcs Empl - Nonassoc	1,811,221	456,588	669,595	685,039
9230003	AEPSC Billed to Client Co	(24,471)	(12,060)	(18,468)	6,056
9230031	SRV-OUTSIDE SERVICES (TECH)	56	19	26	11

American Electric Power

IS8016 YTD Jul 2024 08/08/2024 00:02	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024
9230034	SRV-SOFTWARE LICENSING	14,129	10,373	3,638	118
9230035	Development Project Expense	116	0	0	116
9240000	Property Insurance	691,085	166,076	408,174	116,834
9250000	Injuries and Damages	1,044,571	725,814	272,659	46,098
9250002	Emp Accdent Prvntion-Adm Exp	(11)	(3)	(6)	(2)
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	245,845	229,011	15,121	1,714
9250007	Prsnal Injries&Prop Dmage-Pub	14,683	0	14,683	0
9250010	Frg Ben Loading - Workers Comp	(111,750)	(93,462)	(17,975)	(313)
9260000	Employee Pensions & Benefits	1,480	1,480	0	0
9260001	Edit & Print Empl Pub-Salaries	6	6	0	0
9260002	Pension & Group Ins Admin	20,532	9,440	10,775	317
9260003	Pension Plan	1,247,708	836,665	401,417	9,626
9260004	Group Life Insurance Premiums	79,149	50,009	28,706	434
9260005	Group Medical Ins Premiums	2,911,302	1,984,657	901,723	24,921
9260007	Group L-T Disability Ins Prem	304,827	182,692	121,851	284
9260009	Group Dental Insurance Prem	102,595	70,233	31,407	955
9260010	Training Administration Exp	6,787	4,256	2,218	312
9260012	Employee Activities	7,610	5,813	1,617	180
9260021	Postretirement Benefits - OPEB	53,904	29,356	23,803	745
9260027	Savings Plan Contributions	1,068,035	702,101	358,284	7,650
9260036	Deferred Compensation	4,285	4,285	0	0
9260037	Supplemental Pension	14,497	14,463	34	0
9260050	Frg Ben Loading - Pension	(566,555)	(488,180)	(70,236)	(8,140)
9260051	Frg Ben Loading - Grp Ins	(1,546,660)	(1,332,003)	(194,316)	(20,340)
9260052	Frg Ben Loading - Savings	(454,831)	(385,771)	(61,971)	(7,090)
9260053	Frg Ben Loading - OPEB	(52,494)	(43,609)	(7,994)	(891)
9260055	IntercoFringeOffset- Don't Use	(277,991)	(277,991)	0	0
9260058	Frg Ben Loading - Accrual	(46,683)	(37,403)	(8,620)	(660)
9260060	Amort-Post Retirerment Benefit	126,362	75,589	41,537	9,236
9270000	Franchise Requirements	93,216	93,216	0	0
9280000	Regulatory Commission Exp	6,247	2,746	1,801	1,700
9280001	Regulatory Commission Exp-Adm	212	17	176	19
9280002	Regulatory Commission Exp-Case	1,888,769	975,798	431,364	481,610
9280005	Reg Com Exp-FERC Trans Cases	10,081	177	198	9,705
9280006	State Publ Serv CommissionFees	554,035	554,035	0	0
9301000	General Advertising Expenses	17,214	7,678	4,965	4,572
9301001	Newspaper Advertising Space	20,000	9,047	5,530	5,423
9301003	TV Station Advertising Time	19,720	8,930	5,604	5,186
9301012	Public Opinion Surveys	12,539	12,538	1	1
9301015	Other Corporate Comm Exp	5,164	5,164	0	0
9302000	Misc General Expenses	191,367	76,242	73,774	41,351
9302003	Corporate & Fiscal Expenses	47,528	28,973	14,961	3,594
9302004	Research, Develop&Demonstr Exp	557	201	258	98
9310001	Rents - Real Property	5,600	5,600	0	0
9310002	Rents - Personal Property	31,017	25,569	4,913	536
	Administration & General	**16,685,363**	**7,809,578**	**6,243,807**	**2,632,018**
4111005	Accretion Expense	471,999	8,691	463,308	0
	Accretion	**471,999**	**8,691**	**463,308**	**-**
4116000	Gain From Disposition of Plant	(8,467)	(8,467)	0	0

American Electric Power

INCOME STATEMENT

IS8016
YTD Jul 2024
08/08/2024 00:02

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Jul 2024	Kentucky Power Company - Distribution 110 Actual YTD Jul 2024	Kentucky Power Company - Generation 117 Actual YTD Jul 2024	Kentucky Power Company - Transmission 180 Actual YTD Jul 2024
	Loss/(Gain) on Utility Plant	**(8,467)**	**(8,467)**	**-**	**-**
9302006	Assoc Bus Dev - Materials Sold	116,063	116,063	0	0
9302007	Assoc Business Development Exp	124,786	101,850	225	22,717
	Associated Business Development Expenses	**240,849**	**217,913**	**225**	**22,717**
	Gain on Disposition of Property	**-**	**-**	**-**	**-**
4212000	Loss on Dspsition of Property	174	0	174	0
	Loss on Disposition of Property	**174**	**-**	**174**	**-**
	Loss(Gain) of Sale of Property	**174**	**-**	**174**	**-**
4265009	Factored Cust A/R Exp - Affil	1,847,530	1,847,530	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	1,280,709	1,280,709	0	0
	Opr Exp and Factored A/R	**3,128,239**	**3,128,239**	**-**	**-**
	Water Heaters	**-**	**-**	**-**	**-**
4040007	Cloud Implement - Amort Plant	246,983	173,883	46,361	26,739
4265004	Social & Service Club Dues	24,584	5,755	18,310	519
4265007	Regulatory Expenses	2,603	1,173	735	694
	Expense of Non-Utility Operation	**274,170**	**180,812**	**65,406**	**27,951**
4210009	Misc Non-Op Exp - NonAssoc	16,756	16,644	44	69
	Misc NonOp Expenses - NonAssoc	**16,756**	**16,644**	**44**	**69**
4261000	Donations	933,253	923,993	5,381	3,878
	Donation Contributions	**933,253**	**923,993**	**5,381**	**3,878**
4263001	Penalties	314	211	98	5
	Provision for Penalties	**314**	**211**	**98**	**5**
4264000	Civic and Political Activity	113,942	60,289	27,482	26,174
4264001	Non-deduct Lobbying per IRS	14,223	4,883	6,467	2,873
	Civic & Political Activities	**128,166**	**65,172**	**33,950**	**29,047**
4265002	Other Deductions - Nonassoc	311,591	298,482	8,871	4,238
	Other Deductions	**311,591**	**298,482**	**8,871**	**4,238**
	Shutdown Coal Company Expenses	**-**	**-**	**-**	**-**
	All Other Operational Expenses	**4,792,488**	**4,613,553**	**113,749**	**65,189**
	Operational Expenses	**93,567,564**	**72,990,496**	**63,801,207**	**5,243,727**
5100000	Maint Supv & Engineering	1,047,166	0	1,047,166	0
5110000	Maintenance of Structures	865,037	0	865,037	0
5120000	Maintenance of Boiler Plant	7,268,457	0	7,268,457	0
5120034	BSDR O/U Recovery - Maint Cost	(6,349)	0	(6,349)	0
5120037	KY Steam Maint O/U	(371,592)	0	(371,592)	0
5130000	Maintenance of Electric Plant	2,265,818	0	2,265,818	0
5140000	Maintenance of Misc Steam Plt	988,704	0	988,704	0
5140025	Maint MiscStmPlt Environmental	(14)	0	(14)	0
	Steam Generation Maintenance	**12,057,227**	**-**	**12,057,227**	**-**
	Nuclear Generation Maintenance	**-**	**-**	**-**	**-**
	Hydro Generation Maintenance	**-**	**-**	**-**	**-**
	Other Generation Maintenance	**-**	**-**	**-**	**-**
5680000	Maint Supv & Engineering	17,957	908	523	16,527
5690000	Maintenance of Structures	30,023	0	0	30,023
5691000	Maint of Computer Hardware	3,405	19	(12)	3,398
5692000	Maint of Computer Software	125,019	10,566	4,734	109,719
5693000	Maint of Communication Equip	6,398	0	0	6,398
5700000	Maint of Station Equipment	352,394	1,764	1	350,629

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IS8016 YTD Jul 2024 08/08/2024 00:02	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024
5710000	Maintenance of Overhead Lines	3,257,277	(3)	1	3,257,282
5720000	Maint of Underground Lines	186	0	0	186
5730000	Maint of Misc Trnsmssion Plt	724	43	4	677
	Transmission Maintenance	**3,793,382**	**13,297**	**5,250**	**3,774,838**
5900000	Maint Supv & Engineering	9,942	9,875	23	43
5910000	Maintenance of Structures	8,092	8,095	0	(3)
5920000	Maint of Station Equipment	737,973	733,094	1	4,878
5930000	Maintenance of Overhead Lines	19,606,467	19,610,346	87	518
5930001	Tree and Brush Control	242,011	241,915	0	0
5940000	Maint of Underground Lines	31,217	31,223	(0)	(0)
5950000	Maint of Lne Trnf,Rglators&Dvi	13,090	13,097	0	0
5960000	Maint of Strt Lghtng & Sgnal S	7,008	7,010	0	0
5970000	Maintenance of Meters	21,100	21,113	2	4
5980000	Maint of Misc Distribution Plt	19,964	19,955	1	9
	Distribution Maintenance	**20,696,864**	**20,695,722**	**113**	**5,448**
9350000	Maintenance of General Plant	30,842	26,006	4,836	0
9350001	Maint of Structures - Owned	486,797	482,735	2,370	1,692
9350002	Maint of Structures - Leased	1,512	1,045	322	145
9350012	Maint of Data Equipment	2,659	1,984	675	0
9350013	Maint of Cmmncation Eq-Unall	718,866	690,760	28,540	0
9350015	Maint of Office Furniture & Eq	556,959	288,642	268,317	0
9350023	Site Communications Services	98	72	26	0
9350024	Maint of DA-AMI Comm Equip	1,221	1,117	28	76
	Administration & General Maintenance	**1,798,954**	**1,492,361**	**305,114**	**1,914**
	All Other Maintenance Expenses	**-**	**-**	**-**	**-**
	Maintenance Expenses	**38,346,427**	**22,201,381**	**12,367,704**	**3,782,200**
	Total Operational and Maintenance Expenses	**131,913,992**	**95,191,877**	**76,168,911**	**9,025,926**
4040001	Amort. of Plant	5,582,843	2,774,507	1,935,265	873,071
4060001	Amort of Plt Acq Adj	22,526	0	0	22,526
	DDA Amortization	**5,605,369**	**2,774,507**	**1,935,265**	**895,597**
4073000	Regulatory Debits	(0)	0	(0)	0
4073014	Regulatory Debit - BSDR	284,364	0	284,364	0
	DDA Regulatory Debits	**284,364**	**-**	**284,364**	**-**
4074000	Regulatory Credits	(3,419,642)	0	(3,419,642)	0
4074025	PPA RIDER Over/Under	1,001,353	0	1,001,353	0
	DDA Regulatory Credits	**(2,418,289)**	**-**	**(2,418,289)**	**-**
	Amortization	**3,471,444**	**2,774,507**	**(198,660)**	**895,597**
4030001	Depreciation Exp	61,449,299	26,009,911	21,603,072	13,836,316
4030029	Over/Undr Depr Exp Var Riders	(1,281,138)	0	(1,281,138)	0
	DDA Depreciation	**60,168,161**	**26,009,911**	**20,321,934**	**13,836,316**
	DDA STP Nuclear Decommissioning	**-**	**-**	**-**	**-**
4031001	Depr - Asset Retirement Oblig	413,504	5,577	407,927	0
	DDA Asset Retirement Obligation	**413,504**	**5,577**	**407,927**	**-**
	DDA Removal Costs	**-**	**-**	**-**	**-**
	Depreciation	**60,581,666**	**26,015,488**	**20,729,861**	**13,836,316**
	Depreciation and Amortization	**64,053,110**	**28,789,995**	**20,531,202**	**14,731,913**
	Franchise Taxes	**-**	**-**	**-**	**-**

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IS8016 YTD Jul 2024 08/08/2024 00:02	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024
408100624	State Gross Receipts Tax	11,545	0	11,545	0
	Revenue-kWhr Taxes	**11,545**	**-**	**11,545**	**-**
4081002	FICA	2,196,708	1,509,491	674,737	12,480
4081003	Federal Unemployment Tax	12,909	7,952	4,865	92
4081007	State Unemployment Tax	22,700	7,916	14,701	83
4081033	Fringe Benefit Loading - FICA	(844,277)	(717,023)	(114,495)	(12,759)
4081034	Fringe Benefit Loading - FUT	(4,188)	(3,576)	(538)	(74)
4081035	Fringe Benefit Loading - SUT	(4,580)	(2,794)	(1,635)	(151)
	Payroll Taxes	**1,379,272**	**801,966**	**577,636**	**(329)**
408102022	State Business Occup Taxes	(28,789)	0	(28,789)	0
408102023	State Business Occup Taxes	8,974	0	8,974	0
408102024	State Business Occup Taxes	4,299,095	0	4,299,095	0
	Capacity Taxes	**4,279,280**	**-**	**4,279,280**	**-**
408100521	Real Personal Property Taxes	832,990	778,009	7	54,974
408100522	Real Personal Property Taxes	1,560,190	(10)	1,560,200	0
408100523	Real Personal Property Taxes	12,438,841	6,720,161	1,523,594	4,195,086
408102924	Real-Pers Prop Tax-Cap Leases	361,026	337,883	14,729	8,414
408103624	Real Prop Tax-Cap Leases	7,938	7,938	0	0
408200523	Real Personal Property Taxes	35,798	80	34,953	765
408200524	Real Personal Property Taxes	5,542	0	5,542	0
	Property Taxes	**15,242,325**	**7,844,061**	**3,139,024**	**4,259,239**
	Regulatory Fees	**-**	**-**	**-**	**-**
408101423	Federal Excise Taxes	725	0	725	0
408101424	Federal Excise Taxes	2,110	0	2,110	0
	Production Taxes	**2,836**	**-**	**2,836**	**-**
408101923	State Sales and Use Taxes	1,530	1,530	0	0
408101924	State Sales and Use Taxes	30,703	7,592	23,111	0
	Miscellaneous Taxes	**32,233**	**9,122**	**23,111**	**-**
	Other Non-Income Taxes	**35,068**	**9,122**	**25,946**	**-**
	Taxes Other Than Income Taxes	**20,947,491**	**8,655,149**	**8,033,432**	**4,258,910**
	TOTAL OPERATING EXPENSES	**216,914,592**	**132,637,021**	**104,733,544**	**28,016,749**
	Memo: SEC Total Operating Expenses	**355,097,271**	**377,260,155**	**242,914,894**	**28,018,077**
	OPERATING INCOME	**53,492,306**	**2,180,251**	**(26,180,095)**	**77,485,481**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	104,757	4,746	100,012	0
	Interest & Dividend NonAffiliated	**104,757**	**4,746**	**100,012**	**-**
4190005	Interest Income - Assoc CBP	309	309	0	0
	Interest & Dividend Affiliated	**309**	**309**	**-**	**-**
	Total Interest & Dividend Income	**105,066**	**5,054**	**100,012**	**-**
	Interest & Dividend Carrying Charge	**-**	**-**	**-**	**-**
	Memo: Total Interest & Dividend Income w/ Carrying	**105,066**	**5,054**	**100,012**	**-**
9260042	SERP Pension - Non-Service	(2,252)	(2,242)	(10)	0
9260043	OPEB - Non-Service	1,594,110	622,422	922,445	49,243
9260062	Pension Plan - Non-Service	2,393,772	630,361	1,804,715	(41,304)
	Other Components of Net Periodic Pension	**3,985,630**	**1,250,540**	**2,727,150**	**7,939**

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American Electric Power

IS8016 YTD Jul 2024 08/08/2024 00:02	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024
4191000	Allw Oth Fnds Usd Drng Cnstr	1,389,194	346,199	311,952	731,043
	AFUDC	**1,389,194**	**346,199**	**311,952**	**731,043**
	Gain on Disposition of Equity Investments	-	-	-	-
	Interest LTD FMB	-	-	-	-
4270002	Int on LTD - Install Pur Contr	(1,782,083)	(1,782,083)	0	0
	Interest LTD IPC	**(1,782,083)**	**(1,782,083)**	-	-
4300001	Interest Exp - Assoc Non-CBP	(771,458)	(771,458)	0	0
	Interest LTD Notes Payable - Affiliated	**(771,458)**	**(771,458)**	-	-
	Interest LTD Notes Payable - NonAffiliated	-	-	-	-
	Interest LTD Debentures	-	-	-	-
4270006	Int on LTD - Sen Unsec Notes	(33,581,771)	(33,581,771)	0	0
	Interest LTD Senior Unsecured	**(33,581,771)**	**(33,581,771)**	-	-
	Interest LTD Other - Affil	-	-	-	-
4270005	Int on LTD - Other LTD	(5,652,999)	(5,652,999)	0	0
	Interest LTD Other - NonAffil	**(5,652,999)**	**(5,652,999)**	-	-
	Interest on Long-Term Debt	**(41,788,312)**	**(41,788,312)**	-	-
4300003	Int to Assoc Co - CBP	(2,177,054)	24,994,694	(34,634,479)	7,462,731
	Interest STD - Affil	**(2,177,054)**	**24,994,694**	**(34,634,479)**	**7,462,731**
4310007	Lines Of Credit	(399,510)	(179,529)	(144,835)	(75,146)
	Interest STD - NonAffil	**(399,510)**	**(179,529)**	**(144,835)**	**(75,146)**
	Interest on Short Term Debt	**(2,576,564)**	**24,815,165**	**(34,779,313)**	**7,387,584**
4280002	Amrtz Debt Dscnt&Exp-Instl Pur	(99,952)	(99,952)	0	0
4280003	Amrtz Debt Dscnt&Exp-N/P	(7,735)	(7,735)	0	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	(349,724)	(349,724)	0	0
	Amort of Debt Disc. Prem & Exp	**(457,411)**	**(457,411)**	-	-
4281004	Amrtz Loss Rcquired Debt-Dbnt	(19,630)	(19,630)	0	0
	Amort Loss on Reacquired Debt	**(19,630)**	**(19,630)**	-	-
	Amort Gain on Reacquired Debt	-	-	-	-
	Other Interest - Fuel Recovery	-	-	-	-
4310001	Other Interest Expense	6,225,290	14,453	6,202,867	7,970
4310002	Interest on Customer Deposits	(1,179,809)	(1,179,809)	0	0
9310005	Int on Regulated Fin Leases	(6,668)	0	0	0
	Other Interest - NonAffil	**5,038,813**	**(1,165,356)**	**6,202,867**	**7,970**
	Other Interest Expense - Affil	-	-	-	-
	Interest Rate Hedge Unrealized (Gain)/Loss	-	-	-	-
4320000	Allw Brrwed Fnds Used Cnstr-Cr	2,071,750	534,920	460,092	1,076,739
	AFUDC-Borrowed Funds	**2,071,750**	**534,920**	**460,092**	**1,076,739**
	Total Interest Charges	**(37,731,353)**	**(18,080,623)**	**(28,116,355)**	**8,472,293**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**21,240,842**	**(14,298,578)**	**(51,157,336)**	**86,696,756**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	8,806,857	(5,344,544)	(2,995,034)	17,146,435
4092001	Inc Tax, Oth Inc&Ded-Federal	(2,125,823)	(205,881)	(1,918,910)	(1,032)
	Federal Current Income Tax	**6,681,034**	**(5,550,426)**	**(4,913,943)**	**17,145,403**
4101001	Prov Def I/T Util Op Inc-Fed	29,901,088	6,299,895	19,673,004	3,928,188
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(33,158,387)	(3,515,306)	(28,037,277)	(1,605,804)
	Federal Deferred Income Tax	**(3,257,300)**	**2,784,589**	**(8,364,272)**	**2,322,384**
	Federal Investment Tax Credits	-	-	-	-

American Electric Power

INCOME STATEMENT

IS8016
YTD Jul 2024
08/08/2024 00:02

Layout: IS8016

17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Jul 2024	Kentucky Power Company - Distribution 110 Actual YTD Jul 2024	Kentucky Power Company - Generation 117 Actual YTD Jul 2024	Kentucky Power Company - Transmission 180 Actual YTD Jul 2024
	Federal Income Taxes	**3,423,735**	**(2,765,837)**	**(13,278,216)**	**19,467,787**
409100223	Income Taxes UOI - State	1,013,897	(1,563,225)	(544,065)	3,121,187
409200223	Inc Tax Oth Inc Ded - State	(533,517)	(51,670)	(481,588)	(259)
	State Current Income Tax	**480,381**	**(1,614,895)**	**(1,025,652)**	**3,120,928**
4111002	Prv Def I/T-Cr UtilOpInc-State	(226,356)	0	(226,356)	0
	State Deferred Income Tax	**(226,356)**	**-**	**(226,356)**	**-**
	State Investment Tax Credits	**-**	**-**	**-**	**-**
	State Income Taxes	**254,025**	**(1,614,895)**	**(1,252,008)**	**3,120,928**
	Local Current Income Tax	**-**	**-**	**-**	**-**
	Local Deferred Income Tax	**-**	**-**	**-**	**-**
	Local Investment Tax Credits	**-**	**-**	**-**	**-**
	Local Income Taxes	**-**	**-**	**-**	**-**
	Foreign Current Income Tax	**-**	**-**	**-**	**-**
	Foreign Deferred Income Tax	**-**	**-**	**-**	**-**
	Foreign Investment Tax Credits	**-**	**-**	**-**	**-**
	Foreign Income Taxes	**-**	**-**	**-**	**-**
	Total Income Taxes	**3,677,759**	**(4,380,732)**	**(14,530,224)**	**22,588,715**
	Equity Earnings of Subs	**-**	**-**	**-**	**-**
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	**17,563,083**	**(9,917,846)**	**(36,627,112)**	**64,108,041**
	Discontinued Operations (Net of Taxes)	**-**	**-**	**-**	**-**
	Cumulative Effect of Accounting Changes	**-**	**-**	**-**	**-**
	Extraordinary Income / (Expenses)	**-**	**-**	**-**	**-**
	NET INCOME	**17,563,083**	**(9,917,846)**	**(36,627,112)**	**64,108,041**
	Minority Interest	**-**	**-**	**-**	**-**
	Preferred Stock Dividend Subs	**-**	**-**	**-**	**-**
	Earnings to Common Shareholders	**17,563,083**	**(9,917,846)**	**(36,627,112)**	**64,108,041**
	NET INCOME (LOSS) NODE before PS	**17,563,083**	**(9,917,846)**	**(36,627,112)**	**64,108,041**
	Double Check on Net Income Node after PS	(0)	(0)	-	-

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BS8216 YTD Jul 2024 08/09/2024 16:46	BALANCE SHEET	Kentucky Power Int Consol	Kentucky Power Company - Distribution	Kentucky Power Company - Generation	Kentucky Power Company - Transmission
		BS8216	110	117	180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024
	ASSETS				
	Cash and Cash Equivalents	**640,935**	**640,935**	**0**	**0**
	Other Cash Deposits	**39,370**	**17,496**	**21,256**	**618**
	Customers	15,014,702	12,303,148	831,558	1,879,996
	Accrued Unbilled Revenues	5,868,244	5,868,244	0	0
	Miscellaneous Accounts Receivable	21,288,590	5,352,453	61,470,176	18,793,634
	Allowances for Uncollectible Accounts	(978)	(942)	(7)	(29)
	Accounts Receivable	**42,170,559**	**23,522,903**	**62,301,728**	**20,673,601**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**89,188,194**	**6,690,986**	**79,248,036**	**3,249,172**
	Risk Management Contracts - Current	**11,250,288**	**0**	**11,250,288**	**0**
	Margin Deposits	**2,833,949**	**72,274**	**2,761,675**	**0**
	Unrecovered Fuel - Current	**10,212,586**	**0**	**10,212,586**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**3,992,724**	**2,994,090**	**709,849**	**288,785**
	TOTAL CURRENT ASSETS	**160,328,605**	**33,938,683**	**166,505,418**	**24,212,175**
	Electric Production	**1,262,899,906**	**1,285,627,612**	**1,298,961,303**	**869,361,517**
	Electric Transmission	**864,920,362**	**0**	**0**	**0**
	Electric Distribution	**1,152,154,502**	**0**	**0**	**0**
	General Property, Plant and Equipment	**175,133,196**	**83,276**	**(45,138)**	**1,119,396**
	Construction Work-in-Progress	**181,211,650**	**59,089,155**	**25,239,145**	**96,883,350**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,636,319,616**	**1,344,800,043**	**1,324,155,310**	**967,364,263**
	less: Accumulated Depreciation and Amortization	**(1,235,621,129)**	**(327,798,500)**	**(643,833,164)**	**(263,989,465)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,400,698,487**	**1,017,001,543**	**680,322,146**	**703,374,798**
	Net Regulatory Assets	**598,294,154**	**130,114,831**	**459,253,210**	**8,926,114**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Assets	**26,079,221**	**13,662,677**	**11,649,157**	**767,388**
	Other Non Current Assets	**37,660,979**	**9,900,858**	**23,373,361**	**4,386,760**
	TOTAL OTHER NON-CURRENT ASSETS	**662,034,354**	**153,678,365**	**494,275,728**	**14,080,261**
	TOTAL ASSETS	**3,223,061,445**	**1,204,618,592**	**1,341,103,292**	**741,667,234**
	LIABILITIES				
	Accounts Payable	**91,833,350**	**87,821,430**	**55,959,788**	**12,379,805**
	Advances from Affiliates	**61,202,688**	**(738,748,391)**	**1,050,057,878**	**(250,106,799)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**215,000,000**	**215,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	6,263,600	15,154	6,248,446	0
2440021	S/T Liability MTM Collateral	(592,538)	(15,154)	(577,384)	0
	Risk Management Liabilities - MTM	5,671,062	0	5,671,062	0
	Risk Management Liabilities	**5,671,062**	**0**	**5,671,062**	**0**
	Accrued Taxes	**36,367,741**	**717,856**	**(26,579,175)**	**62,229,060**

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BS8216 YTD Jul 2024 08/09/2024 16:46	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024
	Memo: Property Taxes	38,524,232	20,098,004	6,621,054	11,805,173
	Accrued Interest	**15,509,117**	**15,509,117**	**0**	**0**
	Risk Management Collateral	496,705	0	496,705	0
	Utility Customer Deposits	37,391,895	37,391,895	0	0
	Deposits - Customer and Collateral	**37,888,600**	**37,391,895**	**496,705**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	127,579	49,345	78,235	0
	Obligations under Operating Leases - Current	263,411	132,428	60,683	70,300
	Tax Collections Payable	1,845,117	1,845,117	0	0
	Revenue Refunds - Accrued	459,293	0	142,511	316,782
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	741,930	655,244	79,924	6,762
	Accrued Rents	(5,379)	(5,379)	0	0
	Accrued ICP	1,104,074	1,012,272	87,040	4,762
	Accrued Vacations	2,173,608	1,949,631	202,730	21,247
	Misc Employee Benefits	1,087,700	911,345	174,805	1,550
	Payroll Deductions	101,625	89,881	10,480	1,264
	Severance / SEI	304,065	304,065	0	0
	Accrued Workers Compensation	218,011	205,139	12,900	(29)
2530022	Customer Advance Receipts	2,678,619	2,678,619	0	0
	Customer Advance	2,678,619	2,678,619	0	0
2420511	Control Cash Disburse Account	296,542	296,542	0	0
	Control Cash Disbursement Account	296,542	296,542	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	118,665	0	118,665	0
2300002	ARO - Current	1,442,506	0	1,442,506	0
2420088	Econ. Development Fund Curr	439,675	439,675	0	0
2420512	Unclaimed Funds	19,358	19,358	0	0
2420542	Acc Cash Franchise Req	66,603	66,603	0	0
2420643	Accrued Audit Fees	25,643	10,766	9,696	5,181
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	505,174	504,027	0	1,147
2530112	Other Deferred Credits-Curr	1,361,400	1,361,400	0	0
2530124	Contr In Aid of Constr Advance	304,557	304,557	0	0
	Misc Current and Accrued Liabilities	4,284,263	2,707,068	1,570,866	6,328
	Current Other and Accrued Liabilities	15,289,469	12,649,545	2,281,257	358,667
	Other Current Liabilities	**15,680,460**	**12,831,318**	**2,420,174**	**428,967**
	TOTAL CURRENT LIABILITIES	**479,153,018**	**(369,476,774)**	**1,088,026,432**	**(175,068,968)**
	Long-Term Debt - Affiliated	**25,000,000**	**25,000,000**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,060,807,882**	**1,060,807,882**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(620,906)**	**(620,906)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,060,186,975*	*1,060,186,975*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	1,048,674	9,018	1,039,656	0
2440022	L/T Liability MTM Collateral	(9,018)	(9,018)	0	0
	Long-Term Risk Management Liabilities - MTM	1,039,656	0	1,039,656	0
	Long-Term Risk Management Liabilities	**1,039,656**	**0**	**1,039,656**	**0**

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BS8216 YTD Jul 2024 08/09/2024 16:46	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024	YTD Jul 2024
	Deferred Income Taxes	**473,410,316**	**166,916,674**	**212,474,910**	**94,018,732**
	Deferred Investment Tax Credits	**(0)**	**0**	**(0)**	**0**
	Regulatory Liabilities and Deferred Credits	**110,620,881**	**81,773,712**	**(3,589,785)**	**32,436,955**
	Memo - Reg Liab and Def ITC	*110,620,881*	*81,773,712*	*(3,589,786)*	*32,436,955*
	Asset Retirement Obligation	**85,682,430**	**209,755**	**85,472,675**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**7,708,959**	**11,127,628**	**(5,175,567)**	**1,756,898**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redem	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	733,385	567,645	165,740	0
	Obligations Under Operating Leases	1,686,827	1,178,650	198,708	309,469
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	94,867	94,867	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	31,940	31,940	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	444	0	0	444
2530185	O\U Accounting of ExpensesT	7,351	0	7,351	0
2530188	Long Term Assoc AP	3,781,939	0	0	3,781,939
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	3,906,290	31,940	7,351	3,866,999
	Total Other Deferred Credits	4,001,157	126,807	7,351	3,866,999
	Accumulated Provisions - Rate Refund	688,442	0	0	688,442
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**7,109,810**	**1,873,102**	**371,799**	**4,864,909**
	TOTAL NON-CURRENT LIABILITIES	**1,770,759,026**	**1,347,087,845**	**290,593,687**	**133,077,494**
	TOTAL LIABILITIES	**2,249,912,044**	**977,611,072**	**1,378,620,119**	**(41,991,474)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**527,602,081**	**106,025,371**	**336,884,757**	**84,691,953**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**395,097,320**	**98,578,100**	**(384,689,187)**	**681,208,408**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**973,149,401**	**227,007,520**	**(37,516,827)**	**783,658,708**
	Memo: Total Equity	973,149,401	227,007,520	(37,516,827)	783,658,708
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,223,061,445**	**1,204,618,592**	**1,341,103,292**	**741,667,234**
	out-of-balance	(0)	0	0	(0)

Reserved Section

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Filing Requirements
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BS8216 YTD Jul 2023 08/09/2023 18:38	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jul 2023	YTD Jul 2023	YTD Jul 2023	YTD Jul 2023
	ASSETS				
	Cash and Cash Equivalents	**2,331,822**	**2,331,822**	**0**	**0**
	Other Cash Deposits	**55,764**	**22,325**	**32,470**	**969**
	Customers	38,419,399	37,226,952	570,890	621,558
	Accrued Unbilled Revenues	18,829,160	18,829,160	0	0
	Miscellaneous Accounts Receivable	12,396,507	2,165,312	48,888,942	16,704,353
	Allowances for Uncollectible Accounts	(632,538)	(631,257)	0	(1,280)
	Accounts Receivable	**69,012,528**	**57,590,167**	**49,459,832**	**17,324,631**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**80,405,393**	**8,397,668**	**69,358,386**	**2,649,339**
	Risk Management Contracts - Current	**5,517,735**	**0**	**5,517,735**	**0**
	Margin Deposits	**975,284**	**0**	**975,284**	**0**
	Unrecovered Fuel - Current	**5,874,785**	**0**	**5,874,785**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**3,698,471**	**2,759,750**	**670,416**	**268,304**
	TOTAL CURRENT ASSETS	**167,871,781**	**71,101,733**	**131,888,907**	**20,243,242**
	Electric Production	**1,241,576,733**	**1,220,421,620**	**1,280,736,332**	**820,242,964**
	Electric Transmission	**816,566,032**	**0**	**0**	**0**
	Electric Distribution	**1,090,876,863**	**0**	**0**	**0**
	General Property, Plant and Equipment	**173,608,166**	**83,276**	**24,208**	**1,119,396**
	Construction Work-in-Progress	**155,597,452**	**58,402,351**	**18,835,511**	**78,359,590**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,478,225,247**	**1,278,907,246**	**1,299,596,051**	**899,721,950**
	less: Accumulated Depreciation and Amortization	**(1,184,494,140)**	**(314,836,024)**	**(618,868,995)**	**(250,789,121)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,293,731,108**	**964,071,223**	**680,727,056**	**648,932,829**
	Net Regulatory Assets	**516,565,020**	**123,102,718**	**388,031,271**	**5,431,032**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**332,708**	**0**	**332,708**	**0**
	Employee Benefits and Pension Assets	**21,733,380**	**11,414,521**	**9,775,322**	**543,537**
	Other Non Current Assets	**24,288,397**	**7,196,997**	**14,480,590**	**2,610,810**
	TOTAL OTHER NON-CURRENT ASSETS	**562,919,505**	**141,714,236**	**412,619,890**	**8,585,379**
	TOTAL ASSETS	**3,024,522,393**	**1,176,887,192**	**1,225,235,853**	**677,761,451**
	LIABILITIES				
	Accounts Payable	**78,280,442**	**76,191,009**	**48,310,935**	**9,140,600**
	Advances from Affiliates	**129,452,526**	**(645,320,104)**	**937,668,760**	**(162,896,130)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**425,000,000**	**425,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	3,124,012	0	3,124,012	0
2440021	S/T Liability MTM Collateral	(1,378,480)	0	(1,378,480)	0
	Risk Management Liabilities - MTM	1,745,532	0	1,745,532	0
	Risk Management Liabilities	**1,745,532**	**0**	**1,745,532**	**0**
	Accrued Taxes	**24,845,514**	**9,855,960**	**(12,667,796)**	**27,657,350**

BS8216 YTD Jul 2023 08/09/2023 18:38	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
18A V2099-01-01	Layout : BS8216 Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jul 2023	YTD Jul 2023	YTD Jul 2023	YTD Jul 2023
	Memo: Property Taxes	25,779,934	15,151,940	5,257,174	5,370,820
	Accrued Interest	**11,361,655**	**11,361,655**	**0**	**0**
	Risk Management Collateral	209,262	0	209,262	0
	Utility Customer Deposits	40,109,899	40,109,899	0	0
	Deposits - Customer and Collateral	**40,319,161**	**40,109,899**	**209,262**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	76,460	0	76,460	0
	Obligations under Operating Leases - Current	122,555	58,725	59,673	4,157
	Tax Collections Payable	1,776,861	1,776,861	0	0
	Revenue Refunds - Accrued	113,856	0	113,856	(0)
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	830,174	759,994	64,774	5,406
	Accrued Rents	(8,400)	(8,400)	0	0
	Accrued ICP	1,513,783	1,404,625	103,417	5,741
	Accrued Vacations	2,664,154	2,325,238	316,903	22,013
	Misc Employee Benefits	1,568,553	788,697	778,706	1,150
	Payroll Deductions	120,929	94,935	24,722	1,272
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	204,472	181,140	23,332	0
2530022	Customer Advance Receipts	4,421,056	4,421,056	0	0
	Customer Advance	4,421,056	4,421,056	0	0
2420511	Control Cash Disburse Account	1,772,496	1,772,496	0	0
	Control Cash Disbursement Account	1,772,496	1,772,496	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	111,171	0	111,171	0
2300002	ARO - Current	29,797	0	29,797	0
2420088	Econ. Development Fund Curr	270,592	270,592	0	0
2420512	Unclaimed Funds	7,541	7,541	0	0
2420542	Acc Cash Franchise Req	59,939	59,939	0	0
2420643	Accrued Audit Fees	117,004	48,332	45,401	23,272
2420656	Federal Mitigation Accru (NSR)	244,045	0	244,045	0
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	526,897	525,638	0	1,258
2530112	Other Deferred Credits-Curr	137,959	137,959	0	0
2530124	Contr In Aid of Constr Advance	185,246	185,246	0	0
2530177	Deferred Rev-Bonus Lease Curr	15,178	0	15,178	0
	Misc Current and Accrued Liabilities	1,706,053	1,235,931	445,592	24,530
	Current Other and Accrued Liabilities	16,683,987	14,752,573	1,871,303	60,110
	Other Current Liabilities	**16,883,002**	**14,811,298**	**2,007,436**	**64,268**
	TOTAL CURRENT LIABILITIES	**727,887,830**	**(67,990,284)**	**977,274,128**	**(126,033,913)**
	Long-Term Debt - Affiliated	**25,000,000**	**25,000,000**	**0**	**0**
	Long-Term Debt - Non Affiliated	**753,315,923**	**753,315,923**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**0**	**0**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*753,315,923*	*753,315,923*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	41	0	41	0
2440022	L/T Liability MTM Collateral	(166)	0	(166)	0

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BS8216 YTD Jul 2023 08/09/2023 18:38	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jul 2023	YTD Jul 2023	YTD Jul 2023	YTD Jul 2023
	Long-Term Risk Management Liabilities - MTM	(125)	0	(125)	0
	Long-Term Risk Management Liabilities	**(125)**	**0**	**(125)**	**0**
	Deferred Income Taxes	**462,509,919**	**154,683,323**	**217,893,142**	**89,933,454**
	Deferred Investment Tax Credits	**(0)**	**0**	**(0)**	**0**
	Regulatory Liabilities and Deferred Credits	**91,173,476**	**62,014,114**	**2,685,055**	**26,474,307**
	Memo - Reg Liab and Def ITC	*91,173,475*	*62,014,114*	*2,685,054*	*26,474,307*
	Asset Retirement Obligation	**18,481,215**	**195,284**	**18,285,931**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**8,134,128**	**11,003,057**	**(4,425,732)**	**1,556,803**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redemption	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	243,975	0	243,975	0
	Obligations Under Operating Leases	434,826	203,299	231,527	0
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	106,456	106,456	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	45,727	45,727	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	1,332	0	0	1,332
2530185	O\U Accounting of ExpensesT	1,627	0	1,627	0
2530188	Long Term Assoc AP	2,164,467	0	611,274	1,553,193
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	2,297,769	45,727	612,901	1,639,141
	Total Other Deferred Credits	2,404,225	152,183	612,901	1,639,141
	Accumulated Provisions - Rate Refund	1,690,917	0	37,950	1,652,967
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**4,773,944**	**355,483**	**1,126,353**	**3,292,108**
	TOTAL NON-CURRENT LIABILITIES	**1,363,388,480**	**1,006,567,184**	**235,564,624**	**121,256,672**
	TOTAL LIABILITIES	**2,091,276,310**	**938,576,900**	**1,212,838,752**	**(4,777,240)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,235,187**	**106,025,371**	**336,070,072**	**84,139,743**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**356,560,897**	**109,880,871**	**(333,960,575)**	**580,640,600**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**933,246,083**	**238,310,292**	**12,397,101**	**682,538,691**
	Memo: Total Equity	933,246,083	238,310,292	12,397,101	682,538,691
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,024,522,393**	**1,176,887,192**	**1,225,235,853**	**677,761,451**

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KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - July, 2024

Final

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		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,276,923,610.03	30,328,260.99	(8,867,732.88)	0.00	0.00	1,298,384,138.14
101/106	CLOUD GENERATION	381,874.02	35,891.97	0.00	0.00	0.00	417,765.99
	TOTAL PRODUCTION	**1,277,305,484.05**	**30,364,152.96**	**(8,867,732.88)**	**0.00**	**0.00**	**1,298,801,904.13**
101/106	TRANSMISSION	842,600,699.05	28,939,157.05	(2,178,339.07)	0.00	0.00	869,361,517.03
101/106	CLOUD TRANSMISSION	201,394.70	59,611.26	0.00	0.00	0.00	261,005.96
101/106	DISTRIBUTION	1,249,889,192.92	42,531,127.27	(8,241,412.32)	0.00	0.00	1,284,178,907.87
101/106	CLOUD DISTRIBUTION	1,618,196.01	262,296.55	0.00	0.00	0.00	1,880,492.56
	TOTAL (ACCOUNTS 101 & 106)	**3,371,614,966.73**	**102,156,345.09**	**(19,287,484.27)**	**0.00**	**0.00**	**3,454,483,827.55**
1011001/12	CAPITAL LEASES	1,080,445.85	0.00	0.00	143,751.82	0.00	1,224,197.67
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**3,372,695,412.58**	**102,156,345.09**	**(19,287,484.27)**	**143,751.82**	**0.00**	**3,455,708,025.22**
1050001	PLANT HELD FOR FUTURE USE	801,671.21	0.00	0.00	0.00	0.00	801,671.21
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEGINNING BALANCE	159,612,262.17					
107000X	ADDITIONS		100,669,260.62				
107000X	TRANSFERS		(79,069,873.11)				
107000X	ENDING BALANCE		21,599,387.51				181,211,649.68
107000X	**CLOUD CONSTRUCTION WIP:**						
107000X	BEGINNING BALANCE	1,540,647.27					
107000X	ADDITIONS		608,501.57				
107000X	TRANSFERS		(357,799.78)				
107000X	ENDING BALANCE		250,701.79				1,791,349.06
	TOTAL ELECTRIC UTILITY PLANT	**3,534,649,993.23**	**124,006,434.39**	**(19,287,484.27)**	**143,751.82**	**0.00**	**3,639,512,695.17**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	571,711.48	0.00	(69,345.76)	0.00	0.00	502,365.72
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1210003	NONUTILITY PROPERTY-WIP						
	BEGINNING BALANCE	0.00					
	ADDITIONS		0.00				
	TRANSFERS		0.00				
	ENDING BALANCE		0.00				0.00
1210016	NONUTILITY PROPERTY-CCNC	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	655,168.37	0.00	0.00	0.00	0.00	655,168.37
	TOTAL NONUTILITY PLANT	**1,226,879.85**	**0.00**	**(69,345.76)**	**0.00**	**0.00**	**1,157,534.09**

KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - July, 2024

Final

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		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
.	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	623,339,018.27	22,029,368.51	(7,204,978.01)	(4,113,002.21)	(4,118,311.49)	629,932,095.07
1080001/11	TRANSMISSION	284,929,166.47	13,836,316.16	(1,664,772.14)	(54,498.82)	0.00	297,046,211.67
1080001/11	DISTRIBUTION	376,851,080.91	26,015,902.26	(6,499,941.78)	(2,596,161.11)	(152,964.97)	393,617,915.31
1080013	PRODUCTION	(4,098,119.71)	0.00	0.00	0.00	4,098,119.71	0.00
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(151,934.59)	0.00	0.00	0.00	151,934.59	0.00
	RETIREMENT WORK IN PROGRESS	(13,358,319.70)	0.00	0.00	(6,532,122.39)	6,763,662.14	(13,126,779.95)
	TOTAL (108X accounts)	**1,267,510,891.66**	**61,881,586.93**	**(15,369,691.93)**	**(13,295,784.53)**	**6,742,439.98**	**1,307,469,442.11**
	NUCLEAR					0.00	
1110001	PRODUCTION	12,296,619.11	2,042,094.21	(1,662,754.87)	0.00	0.00	12,675,958.45
1110007	CLOUD IMPLEMENT COST PRODUCTI	103,001.61	46,361.15	0.00	0.00	0.00	149,362.76
1110001	TRANSMISSION	4,150,582.38	918,968.99	(513,566.93)	0.00	0.00	4,555,984.44
1110007	CLOUD IMPLEMENT COST TRANSMIS	36,477.38	26,738.58	0.00	0.00	0.00	63,215.96
1110001	DISTRIBUTION	14,363,824.54	2,841,163.50	(1,741,470.54)	0.00	0.00	15,463,517.50
1110007	CLOUD IMPLEMENT COST DISTRIBUT	417,883.25	173,883.13	0.00	0.00	0.00	591,766.38
	TOTAL (111X accounts)	**31,368,388.27**	**6,049,209.56**	**(3,917,792.34)**	**0.00**	**0.00**	**33,499,805.49**
1011006	CAPITAL LEASES	291,805.66	0.00	0.00	0.00	70,117.78	361,923.44
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**1,299,171,085.59**	**67,930,796.49**	**(19,287,484.27)**	**(13,295,784.53)**	**6,812,557.76**	**1,341,331,171.04**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	172,262.12	3,890.70	(69,345.76)	69,987.88	0.00	176,794.94
1220002	Depr&Amrt of Nonutl Prop-Leasd	0.00	0.00	0.00	0.00	0.00	0.00
1220003	Depr&Amrt of Nonutl Prop-WIP	69,987.88	0.00	0.00	0.00	(69,987.88)	0.00
1220004	Depletion - Owned	0.00	0.00	0.00	0.00	0.00	0.00
1240027	Other Property - RWIP	35,121.36	0.00	0.00	0.00	0.00	35,121.36
1240028	Other Property - Retirement	(46,947.27)	0.00	0.00	0.00	0.00	(46,947.27)
	TOTAL NONUTILITY PLANT	**230,424.09**	**3,890.70**	**(69,345.76)**	**69,987.88**	**(69,987.88)**	**164,969.03**

U.S. Department of Energy
Energy Information Administration
Form EIA-826

Monthly Electric Utility Sales and Revenue Report with State Distributions – 2024

Form Approval
OMB NO.1905-0129
(Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**
Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650.

Utility Name: Kentucky Power Company **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan___ Feb___ Mar___ Apr___ May___ Jun___ Jul_X__ Aug___ Sep___ Oct___ Nov___ Dec__ , 2024

Contact Person: Jeanna Overstreet **Phone number: 614-716-2714**
Email: jmoverstreet@aep.com **Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	25,731	16,382	14,128	-	56,241
	b. Megwatthours	176,177	125,968	169,632		471,777
	c. Number of consumers	130,716	30,731	957		162,404
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					

Note:

KPSC Case No. 2025-00257
Application - Section II
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September 30th, 2024

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed August 2024 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:

1-12	Income Statement
1-3	Details of Operating Revenues
5-10	Operating Expenses – Functional Expenses
12	Detail Statement of Taxes

Balance Sheet:

13	Balance Sheet – Assets & Other Debits
13-15	Balance Sheet – Liabilities & Other Credits
14-15	Deferred Credits
15	Statement of Retained Earnings

Utility Property:

16-17	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Digitally signed by Brian J. Frantz
DN: cn=Brian J. Frantz, c=US, o=AEP, ou=Corporate Accounting, email=bjfrantz@aep.com
Reason: I have reviewed this document
Date: 2024.09.30 09:05:18 -04'00'

Brian J Frantz
Director - Corporate Accounting

American Electric Power

INCOME STATEMENT

IS8016
YTD Aug 2024
09/09/2024 23:42

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Aug 2024	Kentucky Power Company - Distribution 110 Actual YTD Aug 2024	Kentucky Power Company - Generation 117 Actual YTD Aug 2024	Kentucky Power Company - Transmission 180 Actual YTD Aug 2024
		REVENUES				
4400001		Residential Sales-W/Space Htg	96,698,166	96,698,166	0	0
4400002		Residential Sales-W/O Space Ht	44,594,402	45,415,614	(821,212)	0
4400005		Residential Fuel Rev	49,602,016	49,602,016	0	0
	A	**Revenue - Residential Sales**	**190,894,584**	**191,715,796**	**(821,212)**	**-**
4420001		Commercial Sales	66,592,654	67,240,608	(647,954)	0
4420006		Sales to Pub Auth - Schools	10,432,772	10,432,772	0	0
4420007		Sales to Pub Auth - Ex Schools	13,170,773	13,170,773	0	0
4420013		Commercial Fuel Rev	36,816,518	36,816,518	0	0
	A	**Revenue - Commercial Sales**	**127,012,717**	**127,660,671**	**(647,954)**	**-**
	B	**Revenue - Industrial Sales - Affiliated**	**-**	**-**	**-**	**-**
4420002		Industrial Sales (Excl Mines)	48,144,299	49,094,023	(949,724)	0
4420004		Ind Sales-NonAffil(Incl Mines)	12,155,774	12,155,774	0	0
4420016		Industrial Fuel Rev	50,499,195	50,499,195	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**110,799,268**	**111,748,992**	**(949,724)**	**-**
		Revenue - Industrial Sales	**110,799,268**	**111,748,992**	**(949,724)**	**-**
	A	**Revenue - Gas Products Sales**	**-**	**-**	**-**	**-**
	A	**Revenue - Gas Transportation & Storage Sales**	**-**	**-**	**-**	**-**
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	**-**	**-**	**-**	**-**
4440000		Public Street/Highway Lighting	1,197,371	1,201,136	(3,765)	0
4440002		Public St & Hwy Light Fuel Rev	211,379	211,379	0	0
	A	**Revenue - Other Retail Sales**	**1,408,750**	**1,412,515**	**(3,765)**	**-**
	B	**Revenue - Other Retail Sales - Affiliated**	**-**	**-**	**-**	**-**
		Revenue - Retail Sales	**430,115,319**	**432,537,974**	**(2,422,655)**	**-**
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	55,675,506
4561033		PJM NITS Revenue - Affiliated	49,153,130	0	0	49,153,130
4561034		PJM TO Adm. Serv Rev - Aff	170,499	0	0	170,499
4561035		PJM Affiliated Trans NITS Cost	(40,514,600)	0	(40,514,600)	0
4561036		PJM Affiliated Trans TO Cost	(112,522)	0	(112,522)	0
4561059		Affil PJM Trans Enhancmnt Rev	1,042,017	0	0	1,042,017
4561060		Affil PJM Trans Enhancmnt Cost	(858,885)	0	(858,885)	0
4561062		PROVISION RTO Cost - Affi	510,796	0	510,796	0
4561063		PROVISION RTO Rev Affiliated	2,493,024	0	0	2,493,024
	B	**Revenue - Transmission-Affiliated**	**11,883,458**	**-**	**(40,975,211)**	**108,534,175**
4470150		Transm. Rev.-Dedic. Whlsl/Muni	116,948	0	(1,724,467)	1,841,415
4470206		PJM Trans loss credits-OSS	63,975	0	63,975	0
4470209		PJM transm loss charges-OSS	(164,881)	0	(164,881)	0
4561005		PJM Point to Point Trans Svc	1,525,432	0	1,525,432	0
4561006		PJM Trans Owner Admin Rev	61,006	0	0	61,006
4561007		PJM Network Integ Trans Svc	7,382,068	0	0	7,382,068
4561019		Oth Elec Rev Trans Non Affil	35,924	0	0	35,924
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	2,962	0	0	2,962
4561029		PJM NITS Revenue Whsl Cus-NAff	1,651,080	0	0	1,651,080
4561030		PJM TO Serv Rev Whls Cus-NAff	6,257	0	0	6,257
4561045		PJM Non-Aff Gen IPP Rev	3,988	0	0	3,988
4561058		NonAffil PJM Trans Enhncmt Rev	1,145,392	0	0	1,145,392
4561061		NAff PJM RTEP Rev for Whsl-FR	35,002	0	0	35,002
4561064		PROVISION RTO Rev WhslCus-NAf	83,850	0	0	83,850
4561065		PROVISION RTO Rev - NonAff	366,202	0	(1)	366,203
	A	**Revenue - Transmission-NonAffiliated**	**12,315,204**	**-**	**(299,943)**	**12,615,147**
		Revenue - Transmission	**24,198,662**	**-**	**(41,275,154)**	**121,149,322**

KPSC Case No. 2025-00257
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American Electric Power

INCOME STATEMENT

IS8016
YTD Aug 2024
09/09/2024 23:42

Layout: IS8016
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	B	**Revenue - Resale-Affiliated**	-	-	-	-
4470010		Sales for Resale-Bookout Purch	(19)	0	(19)	0
4470027		Whsal/Muni/Pb Ath Fuel Rev	1,708,664	0	1,708,664	0
4470033		Whsal/Muni/Pub Auth Base Rev	1,170,078	0	1,170,078	0
4470082		Financial Electric Realized	(3,622)	0	(3,622)	0
4470089		PJM Energy Sales Margin	455,594	0	455,594	0
4470098		PJM Oper.Reserve Rev-OSS	(31,185)	0	(31,185)	0
4470099		Capacity Cr. Net Sales	(30,949)	0	(30,949)	0
4470100		PJM FTR Revenue-OSS	151,641	0	151,641	0
4470103		PJM Energy Sales Cost	9,911,467	0	9,911,467	0
4470110		PJM TO Admin. Exp.-NonAff.	4	0	4	0
4470115		PJM Meter Corrections-OSS	35,198	0	35,198	0
4470116		PJM Meter Corrections-LSE	202,760	0	202,760	0
4470126		PJM Incremental Imp Cong-OSS	(296,277)	0	(296,277)	0
4470175		OSS Sharing Reclass - Retail	3,674,464	0	3,674,464	0
4470176		OSS Sharing Reclass-Reduction	(3,674,464)	0	(3,674,464)	0
4470215		PJM 30m Suppl Reserve CH OSS	2,731	0	2,731	0
4470220		PJM Regulation - OSS	3,489,641	0	3,489,641	0
4470221		PJM Spinning Reserve - OSS	46,299	0	46,299	0
5550080		PJM Hourly Net Purch.-FERC	(5,709,106)	0	(5,709,106)	0
	A	**Revenue - Resale-NonAffiliated**	**11,102,921**	-	**11,102,921**	-
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**11,102,921**	-	**11,102,921**	-
4470074		Sale for Resale-Aff-Trnf Price	0	0	282,769,705	0
4540001		Rent From Elect Property - Af	767,682	612,029	0	325,259
	B	**Revenue - Other Ele-Affilliated**	**767,682**	**612,029**	**282,769,705**	**325,259**
4500000		Forfeited Discounts	553,000	553,000	0	0
4510001		Misc Service Rev - Nonaffil	94,499	93,907	0	592
4540002		Rent From Elect Property-NAC	2,411,028	1,900	2,389,853	19,275
4540005		Rent from Elec Prop-Pole Attch	3,335,145	3,330,015	0	5,130
4560007		Oth Elect Rev - DSM Program	340,864	340,864	0	0
5010040		Gas Procuremnt Sales Net	(1,141,697)	0	(1,141,697)	0
		Revenue - Other Ele-NonAffilliated	**5,592,840**	**4,319,686**	**1,248,156**	**24,998**
		Revenue - Gas	-	-	-	-
4118002		Comp. Allow Gains Title IV SO2	14	14	0	0
		Gain/(Loss) on Allowances	**14**	**14**	-	-
	A	**Revenue - Other Ele-NonAffilliated**	**5,592,854**	**4,319,701**	**1,248,156**	**24,998**
		Revenue - Other Opr Electric	**6,360,537**	**4,931,730**	**284,017,861**	**350,257**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
4170004		Rev from Non-Util Oper NonAfil	223,457	223,457	0	0
	D	**Revenues Non-Utility Operations - NonAffiliated**	**223,457**	**223,457**	-	-
		Revenues from Non-Utility Operations	**223,457**	**223,457**	-	-
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operatng Rental Income	1,025	1,025	0	0
4180005		Non-Opratng Rntal Inc-Depr	(4,447)	0	0	(4,447)
	D	**Non-Operating Rental Income - NonAffiliated**	**(3,422)**	**1,025**	-	**(4,447)**
		Non-Operating Rental Income	**(3,422)**	**1,025**	-	**(4,447)**
	C	**Non-Operating Misc Income -Affiliated**	-	-	-	-

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American Electric Power

INCOME STATEMENT

IS8016
YTD Aug 2024
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4210002		Misc Non-Op Inc-NonAsc-Rents	1,238	381	630	226
4210007		Misc Non-Op Inc - NonAsc - Oth	6,608	843	5,765	0
	D	**Non-Operating Misc Income - NonAffiliated**	**7,845**	**1,224**	**6,395**	**226**
		Non-Operating Misc Income	**7,845**	**1,224**	**6,395**	**226**
4540004		Rent From Elect Prop-ABD-Nonaf	1,674	1,674	0	0
4560015		Other Electric Revenues - ABD	499,208	383,726	0	115,482
	D	**Associated Business Development Income**	**500,882**	**385,400**	**-**	**115,482**
		Revenue - Other Opr - Other	**728,764**	**611,107**	**6,395**	**111,262**
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	**-**	**-**	**-**	**-**
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***728,764***	***611,107***	***6,395***	***111,262***
		Revenue - Other Operating	**7,089,300**	**5,542,837**	**284,024,255**	**461,519**
4491002		Prov Rate Refund-Nonaffiliated	(69,020)	0	0	(69,020)
4491003		Prov Rate Refund - Retail	(15,013)	0	0	(15,013)
	A	**Provision for Rate Refund - NonAffiliated**	**(84,033)**	**-**	**-**	**(84,033)**
4491004		Prov Rate Refund - Affiliated	(439,535)	0	0	(439,535)
	B	**Provision for Rate Refund - Affiliated**	**(439,535)**	**-**	**-**	**(439,535)**
		Provision for Rate Refund	**(523,568)**	**-**	**-**	**(523,568)**
	A	**Revenue - Power Sales**	**-**	**-**	**-**	**-**
		TOTAL OPERATING REVENUES	**471,982,634**	**438,080,811**	**251,429,367**	**121,087,273**
=(A)		*Memo: G/T/D Revenue*	*459,042,265*	*436,857,674*	*9,628,479*	*12,556,112*
=(B)		*Memo: Other Affiliated Revenue*	*12,211,605*	*612,029*	*241,794,494*	*108,419,899*
=(C)		*Memo: Revenue-Oth Opr-Oth Af*	-	-	-	-
=(D)		*Memo: Revenue-Oth Opr-Oth No*	*728,764*	*611,107*	*6,395*	*111,262*
		Memo: Total Operating Revenues	*471,982,634*	*438,080,811*	*251,429,367*	*121,087,273*
=(E)=(B)+(C)		*Memo: Affiliated Revenue*	***12,211,605***	***612,029***	***241,794,494***	***108,419,899***
=(F)=(D)+(A)		*Memo: Non-Affiliated Revenue*	***459,771,029***	***437,468,781***	***9,634,873***	***12,667,374***
		Memo: Total Operating Revenues	***471,982,634***	***438,080,811***	***251,429,367***	***121,087,273***
		FUEL EXPENSES				
5010000		Fuel	4,490,594	2	4,490,590	1
5010001		Fuel Consumed	57,352,208	0	57,352,208	0
5010003		Fuel - Procure Unload & Handle	2,339,356	0	2,339,356	0
5010012		Ash Sales Proceeds	12,671	0	12,671	0
5010013		Fuel Survey Activity	49,281	0	49,281	0
5010019		Fuel Oil Consumed	2,374,792	0	2,374,792	0
5010020		Nat Gas Consumed Steam	23,811,687	0	23,811,687	0
5010021		Transp Gas Consumed Steam	591,652	0	591,652	0
5010027		Gypsum handling/disposal costs	963,248	0	963,248	0
5010028		Gypsum Sales Proceeds	(942,159)	0	(942,159)	0
5010034		Gas Transp Res Fees-Steam	4,246,703	0	4,246,703	0
		Fuel Expense Total	**95,290,033**	**2**	**95,290,029**	**1**
5010005		Fuel - Deferred	1,655,699	0	1,655,699	0
		Deferred Fuel Expense	**1,655,699**	**-**	**1,655,699**	**-**
		Over Under Fuel Expense				
		Fuel for Electric Generation	**96,945,732**	**2**	**96,945,728**	**1**
		Fuel from Affiliates for Electric Generation	**-**	**-**	**-**	**-**
5090000		Allow Consum Title IV SO2	27,013	0	27,013	0
5090009		Allow Consumpt CSAPR SO2	130	0	130	0
5570009		Other Pwr Exp- REC's - RETAIL	446	0	446	0
		Allowances - Consumption	**27,589**	**-**	**27,589**	**-**

American Electric Power

IS8016 YTD Aug 2024 09/09/2024 23:42	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024
5020002	Urea Expense	896,349	0	896,349	0
5020004	Lime-Related Expenses	1,442,669	0	1,442,669	0
	Emissions Control - Chemicals	**2,339,018**	**-**	**2,339,018**	**-**
	Total Fuel for Electric Generation	**99,312,340**	**2**	**99,312,336**	**1**
	Memo: NonAff Fuel/Allow/Emissions	***99,312,340***	***2***	***99,312,336***	***1***
5550004	Purchased Power-Pool Capacity	373,078	0	373,078	0
5550029	Purch Power-Assoc-Trnsfr Price	0	282,769,705	0	0
	Purchased Electricity from AEP - Affiliates	**373,078**	**282,769,705**	**373,078**	**-**
5550001	Purch Pwr-NonTrading-Nonassoc	53,425,039	0	53,425,039	0
5550023	Purch Power Capacity -NA	613,063	0	613,063	0
5550039	PJM Inadvertent Mtr Res-OSS	5,183	0	5,183	0
5550040	PJM Inadvertent Mtr Res-LSE	52,983	0	52,983	0
5550074	PJM Reactive-Charge	2,416,213	0	2,416,213	0
5550075	PJM Reactive-Credit	(956,584)	0	(956,584)	0
5550076	PJM Black Start-Charge	715,550	0	715,550	0
5550078	PJM Regulation-Charge	410,011	0	410,011	0
5550079	PJM Regulation-Credit	(11,760)	0	(11,760)	0
5550083	PJM Sync & Non Sync-Charge	308,993	0	308,993	0
5550084	PJM Sync & Non Sync-Credit	(25,729)	0	(25,729)	0
5550123	PJM OpRes-LSE-Charge	972,923	0	971,597	1,326
5550124	PJM Implicit Congestion-LSE	4,546,458	0	4,546,458	0
5550132	PJM FTR Revenue-LSE	(4,888,442)	0	(4,888,442)	0
5550137	PJM OpRes-LSE-Credit	(49,612)	0	(49,612)	0
5550153	PurchPower-Rockport Def-NonAff	152,680	0	152,680	0
5550326	PJM Transm Loss Charges - LSE	3,948,229	0	3,948,229	0
5550327	PJM Transm Loss Credits-LSE	(1,616,655)	0	(1,616,655)	0
5550328	PJM FC Penalty Credit	(2,848)	0	(2,848)	0
	Purchased Electricity for Resale - NonAffiliated	**60,015,694**	**-**	**60,014,369**	**1,326**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**
8140000	Underground Storage Expenses	1,637	0	1,637	0
	Purchased Gas for Resale - NonAffiliated	**1,637**	**-**	**1,637**	**-**
	Total Purchased Power	**60,390,410**	**282,769,705**	**60,389,084**	**1,326**
	GROSS MARGIN	**312,279,884**	**155,311,103**	**91,727,947**	**121,085,946**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	3,168,230	(16,780)	3,178,793	6,217
5020000	Steam Expenses	1,039,615	0	1,039,615	0
5050000	Electric Expenses	27,279	0	27,279	0
5060000	Misc Steam Power Expenses	4,646,423	61,428	4,579,591	5,404
5060002	Misc Steam Power Exp-Assoc	35,148	0	35,148	0
5060004	NSR Settlement Expense	10,130	0	10,130	0
5060011	BSRR O/U Recovery-Oper Costs	367	0	367	0
	Steam Generation Op Exp	**8,927,192**	**44,648**	**8,870,923**	**11,621**
	Nuclear Generation Op Exp	**-**	**-**	**-**	**-**
	Hydro Generation Op Exp	**-**	**-**	**-**	**-**
5560000	Sys Control & Load Dispatching	42,875	0	42,875	0
5570000	Other Expenses	577,416	0	577,416	0
5570007	Other Pwr Exp - Wholesale RECs	245	245	0	0
5570010	OH Auction Exp - Incremental	6	0	6	0
5757000	PJM Admin-MAM&SC- OSS	54,137	0	54,137	0
5757001	PJM Admin-MAM&SC- Internal	974,515	0	974,515	0

American Electric Power

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	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024
	Other Generation Op Exp	**1,649,193**	**245**	**1,648,948**	**-**
5600000	Oper Supervision & Engineering	1,481,725	40,786	15,885	1,425,053
5612000	Load Dispatch-Mntr&Op TransSys	259,557	2,530	337	256,690
5614000	PJM Admin-SSC&DS-OSS	55,123	0	55,123	0
5614001	PJM Admin-SSC&DS-Internal	895,252	0	895,252	0
5614009	GreenHat Settlement	3,535	0	3,535	0
5615000	Reliability,Plng&Stds Develop	46,144	1,067	146	44,930
5618000	PJM Admin-RP&SDS-OSS	17,885	0	17,885	0
5618001	PJM Admin-RP&SDS- Internal	304,222	0	304,222	0
5620001	Station Expenses - Nonassoc	143,822	(1)	(1)	143,825
5630000	Overhead Line Expenses	15,031	1	0	15,031
5640000	Underground Line Expenses	16	0	0	16
5650002	Transmssn Elec by Others-NAC	64,754	0	64,754	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	55,675,506	0	0
5650012	PJM Trans Enhancement Charge	1,379,318	0	1,379,318	0
5650015	PJM TO Serv Exp - Aff	113,002	0	113,002	0
5650016	PJM NITS Expense - Affiliated	49,766,402	0	49,766,402	0
5650019	Affil PJM Trans Enhncement Exp	3,665,993	0	3,665,993	0
5650020	PROVISION RTO Affl Expense	(3,212,010)	0	(3,212,010)	0
5650021	PJM NITS Expense - Non-Affilia	578,003	0	578,003	0
5650023	Amort of PROVISION RTO Expense	36,540	0	36,540	0
5660000	Misc Transmission Expenses	924,390	118,153	2,439	803,799
5660009	PJM OATT LSE Over-Under Adjust	1,248,885	0	1,248,885	0
5660011	Misc Transm Exp - Affiliate	2,372	0	0	2,372
5670002	Rents - Associated	0	0	0	169,606
	Transmission Op Exp	**57,789,961**	**55,838,043**	**54,935,711**	**2,861,321**
5800000	Oper Supervision & Engineering	695,252	691,454	860	2,972
5810000	Load Dispatching	527	527	0	0
5820000	Station Expenses	245,364	242,007	45	3,312
5830000	Overhead Line Expenses	209,380	209,532	(1)	28
5840000	Underground Line Expenses	224,720	224,454	157	110
5850000	Street Lighting & Signal Sys E	23,059	23,062	0	0
5860000	Meter Expenses	1,008,525	1,009,262	55	102
5870000	Customer Installations Exp	139,279	139,382	2	(57)
5880000	Miscellaneous Distribution Exp	4,902,293	4,884,508	798	17,374
5890001	Rents - Nonassociated	596,820	596,820	0	0
5890002	Rents - Associated	57,454	57,454	0	0
	Distribution Op Exp	**8,102,674**	**8,078,462**	**1,916**	**23,840**
9010000	Supervision - Customer Accts	5,801	5,744	14	44
9020000	Meter Reading Expenses	25,766	25,766	0	0
9020002	Meter Reading - Regular	204,023	204,089	0	0
9020003	Meter Reading - Large Power	20,753	20,754	0	0
9030000	Cust Records & Collection Exp	206,878	204,484	2	2,392
9030001	Customer Orders & Inquiries	1,979,133	1,978,666	146	355
9030002	Manual Billing	7,360	7,330	16	15
9030003	Postage - Customer Bills	407,927	407,927	0	0
9030004	Cashiering	35,814	35,814	0	0
9030005	Collection Agents Fees & Exp	1,582	1,582	0	0
9030006	Credit & Oth Collection Activi	452,960	453,273	0	0
9030007	Collectors	218,991	218,991	0	0
9030009	Data Processing	24,303	24,292	5	5

American Electric Power

IS8016 YTD Aug 2024 09/09/2024 23:42	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024
9040007	Uncoll Accts - Misc Receivable	9,514	9,477	7	31
9050000	Misc Customer Accounts Exp	13,887	13,887	0	0
9070000	Supervision - Customer Service	39,889	39,901	(2)	(6)
9080000	Customer Assistance Expenses	865,926	865,957	0	0
9080009	Cust Assistance Expense - DSM	361,597	361,547	0	52
9100000	Misc Cust Svc&Informational Ex	4,219	1,979	1,152	1,089
	Customer Service and Information Op Exp	**4,886,324**	**4,881,457**	**1,340**	**3,976**
9120000	Demonstrating & Selling Exp	6,758	6,750	2	6
9120003	Demo & Selling Exp - Area Dev	28	28	0	0
9130001	Advertising Exp - Residential	80	72	7	1
	Sales Expenses	**6,866**	**6,849**	**10**	**7**
	Memo: Insurance (9240 9250)	**2,199,677**	**1,216,230**	**792,399**	**191,048**
9200000	Administrative & Gen Salaries	8,570,163	4,014,571	3,195,679	1,359,922
9210001	Off Supl & Exp - Nonassociated	522,892	333,397	138,869	50,662
9210003	Office Supplies & Exp - Trnsf	161	71	62	28
9210020	EMP RECOG - Over 100 Dollars	2	2	1	0
9210021	EMP TRAVEL - Airfare	81	39	33	10
9210022	MEALS & ENT-100 Pct DEDUCTIBLE	95	38	46	12
9210023	EMP TRAVEL-MILEAGE	547	280	173	94
9210024	EMP TRAVEL-PARKING	13	7	5	1
9210025	MEALS & ENT-50 Pct DEDUCTIBLE	43	26	15	2
9210026	EMP TRAVEL-CAR RENTAL	24	14	9	2
9210027	EMP TRAVEL-TAXI AND SHUTTLE	3	1	1	0
9210028	EMP TRAVEL-HOTEL & LODGING	520	216	229	75
9210030	EMP TRAVEL-OTHER	122	92	29	1
9210031	SAFETY EQUIPMENT AND SUPPLIES	7	2	4	1
9210032	FUEL	7	5	2	0
9210033	FOOD SERVICE-CATERING	7	3	3	2
9210034	In-House Training & Seminars	106	0	0	106
9210037	OEM/TECHNICAL TRAINING	88	0	0	88
9210040	DUES-BUSINESS/PROFESSIONAL	3	1	1	1
9210041	VEHICLE-LICENSE FEES	3	1	1	1
9220000	Administrative Exp Trnsf - Cr	(147,930)	(147,930)	(0)	(0)
9220001	Admin Exp Trnsf to Cnstrction	(328,767)	(328,767)	0	0
9220002	Admin Exp Trnsf Const-Mngerial	0	(0)	0	0
9220004	Admin Exp Trnsf to ABD	8	8	0	0
9220005	Overhead Loadings	(456,712)	(302,193)	(131,954)	(22,565)
9230001	Outside Svcs Empl - Nonassoc	2,089,023	597,613	738,069	753,342
9230003	AEPSC Billed to Client Co	(118,015)	(44,907)	(50,551)	(22,557)
9230024	SRV-MAIL/MESSENGER-POSTAGE	1	1	0	0
9230031	SRV-OUTSIDE SERVICES (TECH)	56	19	26	11
9230034	SRV-SOFTWARE LICENSING	14,267	10,473	3,675	119
9230035	Development Project Expense	116	0	0	116
9240000	Property Insurance	788,633	190,497	464,244	133,893
9250000	Injuries and Damages	1,199,090	832,341	311,778	54,971
9250002	Emp Accdent Prvntion-Adm Exp	113	39	38	36
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	325,250	305,078	17,515	2,656
9250007	Prsnal Injries&Prop Dmage-Pub	20,179	0	20,179	0
9250010	Frg Ben Loading - Workers Comp	(133,588)	(111,725)	(21,354)	(509)
9260000	Employee Pensions & Benefits	1,696	1,696	0	0
9260001	Edit & Print Empl Pub-Salaries	24	12	9	4

American Electric Power

IS8016 YTD Aug 2024 09/09/2024 23:42	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024
9260002	Pension & Group Ins Admin	20,639	9,483	10,837	319
9260003	Pension Plan	1,425,952	956,189	458,763	11,001
9260004	Group Life Insurance Premiums	90,245	57,325	32,424	495
9260005	Group Medical Ins Premiums	3,288,863	2,233,136	1,027,076	28,650
9260007	Group L-T Disability Ins Prem	369,636	219,107	150,178	350
9260009	Group Dental Insurance Prem	115,514	78,757	35,666	1,091
9260010	Training Administration Exp	6,920	4,341	2,250	330
9260012	Employee Activities	7,972	6,023	1,758	191
9260021	Postretirement Benefits - OPEB	61,604	33,549	27,204	851
9260027	Savings Plan Contributions	1,207,926	791,808	407,512	8,606
9260036	Deferred Compensation	4,285	4,285	0	0
9260037	Supplemental Pension	16,568	16,529	39	0
9260050	Frg Ben Loading - Pension	(637,471)	(548,770)	(79,479)	(9,223)
9260051	Frg Ben Loading - Grp Ins	(1,735,482)	(1,494,157)	(218,459)	(22,866)
9260052	Frg Ben Loading - Savings	(516,726)	(438,308)	(70,470)	(7,948)
9260053	Frg Ben Loading - OPEB	(61,349)	(51,049)	(9,295)	(1,005)
9260055	IntercoFringeOffset- Don't Use	(301,710)	(301,710)	0	0
9260058	Frg Ben Loading - Accrual	(139,607)	(116,973)	(21,283)	(1,351)
9260060	Amort-Post Retirerment Benefit	144,413	86,387	47,471	10,555
9270000	Franchise Requirements	106,531	106,531	0	0
9280000	Regulatory Commission Exp	6,192	2,726	1,782	1,684
9280001	Regulatory Commission Exp-Adm	209	16	175	18
9280002	Regulatory Commission Exp-Case	2,096,779	1,068,696	495,344	532,743
9280005	Reg Com Exp-FERC Trans Cases	13,948	294	321	13,333
9280006	State Publ Serv CommissionFees	633,467	633,467	0	0
9301000	General Advertising Expenses	15,914	7,106	4,583	4,225
9301001	Newspaper Advertising Space	20,000	9,047	5,530	5,423
9301003	TV Station Advertising Time	19,228	8,713	5,459	5,055
9301012	Public Opinion Surveys	12,539	12,538	1	1
9301015	Other Corporate Comm Exp	5,284	5,284	0	0
9302000	Misc General Expenses	199,332	78,324	78,094	42,914
9302003	Corporate & Fiscal Expenses	70,972	38,733	25,040	7,198
9302004	Research, Develop&Demonstr Exp	557	201	258	98
9310001	Rents - Real Property	6,400	6,400	0	0
9310002	Rents - Personal Property	35,391	29,228	5,566	597
	Administration & General	**18,959,268**	**8,904,272**	**7,111,181**	**2,943,862**
4111005	Accretion Expense	889,576	10,097	879,479	0
	Accretion	**889,576**	**10,097**	**879,479**	**-**
4116000	Gain From Disposition of Plant	(9,677)	(9,677)	0	0
	Loss/(Gain) on Utility Plant	**(9,677)**	**(9,677)**	**-**	**-**
9302006	Assoc Bus Dev - Materials Sold	116,245	116,245	0	0
9302007	Assoc Business Development Exp	140,672	114,044	207	26,427
	Associated Business Development Expenses	**256,917**	**230,289**	**207**	**26,427**
	Gain on Disposition of Property	**-**	**-**	**-**	**-**
4212000	Loss on Dspsition of Property	174	0	174	0
	Loss on Disposition of Property	**174**	**-**	**174**	**-**
	Loss(Gain) of Sale of Property	**174**	**-**	**174**	**-**
4265009	Factored Cust A/R Exp - Affil	2,202,357	2,202,357	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	1,404,143	1,404,143	0	0
	Opr Exp and Factored A/R	**3,606,500**	**3,606,500**	**-**	**-**
	Water Heaters	**-**	**-**	**-**	**-**

American Electric Power

INCOME STATEMENT

IS8016
YTD Aug 2024
09/09/2024 23:42

Layout: IS8016

17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Aug 2024	Kentucky Power Company - Distribution 110 Actual YTD Aug 2024	Kentucky Power Company - Generation 117 Actual YTD Aug 2024	Kentucky Power Company - Transmission 180 Actual YTD Aug 2024
4040007	Cloud Implement - Amort Plant	285,347	200,934	53,324	31,089
4265004	Social & Service Club Dues	30,419	8,323	20,022	2,074
4265007	Regulatory Expenses	3,476	1,558	992	927
	Expense of Non-Utility Operation	**319,242**	**210,815**	**74,337**	**34,090**
4210009	Misc Non-Op Exp - NonAssoc	16,874	16,689	79	105
	Misc NonOp Expenses - NonAssoc	**16,874**	**16,689**	**79**	**105**
4261000	Donations	1,076,317	1,064,241	6,556	5,521
	Donation Contributions	**1,076,317**	**1,064,241**	**6,556**	**5,521**
4263001	Penalties	1,794	705	785	304
	Provision for Penalties	**1,794**	**705**	**785**	**304**
4264000	Civic and Political Activity	120,579	63,260	29,415	27,907
4264001	Non-deduct Lobbying per IRS	14,223	4,883	6,467	2,873
	Civic & Political Activities	**134,803**	**68,144**	**35,882**	**30,779**
4265002	Other Deductions - Nonassoc	323,453	305,517	12,704	5,232
	Other Deductions	**323,453**	**305,517**	**12,704**	**5,232**
	Shutdown Coal Company Expenses	**-**	**-**	**-**	**-**
	All Other Operational Expenses	**5,478,983**	**5,272,610**	**130,343**	**76,031**
	Operational Expenses	**106,937,451**	**83,257,297**	**73,580,231**	**5,947,085**
5100000	Maint Supv & Engineering	1,214,301	0	1,214,301	0
5110000	Maintenance of Structures	1,115,448	0	1,115,448	0
5120000	Maintenance of Boiler Plant	8,213,992	0	8,213,992	0
5120025	Maint of Blr Plt Environmental	1	0	1	0
5120034	BSDR O/U Recovery - Maint Cost	(7,167)	0	(7,167)	0
5120037	KY Steam Maint O/U	(429,863)	0	(429,863)	0
5130000	Maintenance of Electric Plant	2,377,964	0	2,377,964	0
5140000	Maintenance of Misc Steam Plt	1,123,163	0	1,123,163	0
5140025	Maint MiscStmPlt Environmental	(14)	0	(14)	0
	Steam Generation Maintenance	**13,607,825**	**0**	**13,607,824**	**0**
	Nuclear Generation Maintenance	**-**	**-**	**-**	**-**
	Hydro Generation Maintenance	**-**	**-**	**-**	**-**
	Other Generation Maintenance	**-**	**-**	**-**	**-**
5680000	Maint Supv & Engineering	18,692	908	581	17,203
5690000	Maintenance of Structures	32,314	0	0	32,314
5691000	Maint of Computer Hardware	4,600	54	(1)	4,547
5692000	Maint of Computer Software	143,578	10,907	5,239	127,432
5693000	Maint of Communication Equip	8,142	0	0	8,142
5700000	Maint of Station Equipment	375,550	1,771	0	373,779
5710000	Maintenance of Overhead Lines	4,070,952	(5)	0	4,070,960
5720000	Maint of Underground Lines	411	0	0	411
5730000	Maint of Misc Trnsmssion Plt	1,409	48	5	1,356
	Transmission Maintenance	**4,655,649**	**13,685**	**5,824**	**4,636,144**
5900000	Maint Supv & Engineering	10,987	10,876	35	75
5910000	Maintenance of Structures	9,130	9,128	0	2
5920000	Maint of Station Equipment	775,070	767,148	1	7,922
5930000	Maintenance of Overhead Lines	22,894,089	22,898,838	7	102
5930001	Tree and Brush Control	283,944	283,853	0	0
5940000	Maint of Underground Lines	36,499	36,505	0	0
5950000	Maint of Lne Trnf,Rglators&Dvi	13,937	13,944	0	0
5960000	Maint of Strt Lghtng & Sgnal S	8,211	8,212	0	0
5970000	Maintenance of Meters	24,132	24,153	0	1
5980000	Maint of Misc Distribution Plt	22,197	22,179	1	17

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IS8016 YTD Aug 2024 09/09/2024 23:42	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024
	Distribution Maintenance	**24,078,195**	**24,074,836**	**44**	**8,119**
9350000	Maintenance of General Plant	17,955	13,119	4,836	0
9350001	Maint of Structures - Owned	563,982	558,801	3,160	2,021
9350002	Maint of Structures - Leased	1,559	1,059	343	157
9350012	Maint of Data Equipment	3,025	2,251	774	0
9350013	Maint of Cmmncation Eq-Unall	798,912	768,929	30,474	0
9350015	Maint of Office Furniture & Eq	640,711	329,577	311,135	0
9350023	Site Communications Services	98	72	26	0
9350024	Maint of DA-AMI Comm Equip	5,261	5,110	47	106
	Administration & General Maintenance	**2,031,504**	**1,678,918**	**350,795**	**2,284**
	All Other Maintenance Expenses	**-**	**-**	**-**	**-**
	Maintenance Expenses	**44,373,173**	**25,767,439**	**13,964,487**	**4,646,547**
	Total Operational and Maintenance Expenses	**151,310,624**	**109,024,735**	**87,544,718**	**10,593,632**
4040001	Amort. of Plant	6,301,587	3,133,261	2,172,121	996,205
4060001	Amort of Plt Acq Adj	25,744	0	0	25,744
	DDA Amortization	**6,327,331**	**3,133,261**	**2,172,121**	**1,021,949**
4073000	Regulatory Debits	(0)	0	(0)	0
4073014	Regulatory Debit - BSDR	301,730	0	301,730	0
	DDA Regulatory Debits	**301,730**	**-**	**301,730**	**-**
4074000	Regulatory Credits	(3,234,041)	0	(3,234,041)	0
4074025	PPA RIDER Over/Under	1,951,196	0	1,951,196	0
	DDA Regulatory Credits	**(1,282,845)**	**-**	**(1,282,845)**	**-**
	Amortization	**5,346,216**	**3,133,261**	**1,191,006**	**1,021,949**
4030001	Depreciation Exp	70,316,433	29,776,032	24,691,639	15,848,762
4030029	Over/Undr Depr Exp Var Riders	(1,102,294)	0	(1,102,294)	0
	DDA Depreciation	**69,214,139**	**29,776,032**	**23,589,345**	**15,848,762**
	DDA STP Nuclear Decommissioning	**-**	**-**	**-**	**-**
4031001	Depr - Asset Retirement Oblig	572,705	6,433	566,272	0
	DDA Asset Retirement Obligation	**572,705**	**6,433**	**566,272**	**-**
	DDA Removal Costs	**-**	**-**	**-**	**-**
	Depreciation	**69,786,843**	**29,782,465**	**24,155,616**	**15,848,762**
	Depreciation and Amortization	**75,133,059**	**32,915,726**	**25,346,622**	**16,870,711**
	Franchise Taxes	**-**	**-**	**-**	**-**
408100624	State Gross Receipts Tax	13,197	3	13,194	0
	Revenue-kWhr Taxes	**13,197**	**3**	**13,194**	**-**
4081002	FICA	2,383,635	1,618,744	750,694	14,198
4081003	Federal Unemployment Tax	13,047	8,105	4,850	92
4081007	State Unemployment Tax	22,817	8,013	14,721	83
4081033	Fringe Benefit Loading - FICA	(960,381)	(815,811)	(130,258)	(14,312)
4081034	Fringe Benefit Loading - FUT	(4,759)	(4,059)	(615)	(85)
4081035	Fringe Benefit Loading - SUT	(5,192)	(3,181)	(1,852)	(159)
	Payroll Taxes	**1,449,166**	**811,810**	**637,540**	**(183)**
408102022	State Business Occup Taxes	(28,789)	0	(28,789)	0
408102023	State Business Occup Taxes	8,974	0	8,974	0
408102024	State Business Occup Taxes	4,913,251	0	4,913,251	0
	Capacity Taxes	**4,893,437**	**-**	**4,893,437**	**-**
408100521	Real Personal Property Taxes	832,990	778,009	7	54,974
408100522	Real Personal Property Taxes	1,560,190	(10)	1,560,200	0
408100523	Real Personal Property Taxes	14,446,457	7,680,200	1,971,873	4,794,384

American Electric Power

INCOME STATEMENT

IS8016
YTD Aug 2024
09/09/2024 23:42

Layout: IS8016

17A V2099-01-01 | Account: GL_ACCT_SEC | Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Aug 2024	Kentucky Power Company - Distribution 110 Actual YTD Aug 2024	Kentucky Power Company - Generation 117 Actual YTD Aug 2024	Kentucky Power Company - Transmission 180 Actual YTD Aug 2024
408102922	Real-Pers Prop Tax-Cap Leases	(372,463)	(187,830)	(5,727)	(178,907)
408102924	Real-Pers Prop Tax-Cap Leases	412,127	386,152	16,359	9,616
408103623	Real Prop Tax-Cap Leases	7,431	7,431	0	0
408103624	Real Prop Tax-Cap Leases	9,072	9,072	0	0
408200523	Real Personal Property Taxes	35,798	80	34,953	765
408200524	Real Personal Property Taxes	11,084	0	11,084	0
	Property Taxes	**16,942,686**	**8,673,105**	**3,588,749**	**4,680,833**
	Regulatory Fees	**-**	**-**	**-**	**-**
408101423	Federal Excise Taxes	725	0	725	0
408101424	Federal Excise Taxes	2,110	0	2,110	0
	Production Taxes	**2,836**	**-**	**2,836**	**-**
408101923	State Sales and Use Taxes	1,530	1,530	0	0
408101924	State Sales and Use Taxes	34,956	8,547	26,409	0
	Miscellaneous Taxes	**36,487**	**10,077**	**26,409**	**-**
	Other Non-Income Taxes	**39,322**	**10,077**	**29,245**	**-**
	Taxes Other Than Income Taxes	**23,337,809**	**9,494,995**	**9,162,165**	**4,680,649**
	TOTAL OPERATING EXPENSES	**249,781,492**	**151,435,456**	**122,053,505**	**32,144,992**
	Memo: SEC Total Operating Expenses	**409,484,242**	**434,205,163**	**281,754,925**	**32,146,320**
	OPERATING INCOME	**62,498,392**	**3,875,648**	**(30,325,558)**	**88,940,953**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	117,083	5,207	111,877	0
	Interest & Dividend NonAffiliated	**117,083**	**5,207**	**111,877**	**-**
4190005	Interest Income - Assoc CBP	309	309	0	0
	Interest & Dividend Affiliated	**309**	**309**	**-**	**-**
	Total Interest & Dividend Income	**117,392**	**5,515**	**111,877**	**-**
	Interest & Dividend Carrying Charge	**-**	**-**	**-**	**-**
	Memo: Total Interest & Dividend Income w/ Carrying	**117,392**	**5,515**	**111,877**	**-**
9260042	SERP Pension - Non-Service	(2,575)	(2,563)	(13)	0
9260043	OPEB - Non-Service	1,838,802	722,803	1,059,721	56,278
9260062	Pension Plan - Non-Service	2,735,739	720,412	2,062,532	(47,205)
	Other Components of Net Periodic Pension	**4,571,966**	**1,440,652**	**3,122,241**	**9,073**
4191000	Allw Oth Fnds Usd Drng Cnstr	1,611,898	398,642	355,649	857,608
	AFUDC	**1,611,898**	**398,642**	**355,649**	**857,608**
	Gain on Disposition of Equity Investments	**-**	**-**	**-**	**-**
	Interest LTD FMB	**-**	**-**	**-**	**-**
4270002	Int on LTD - Install Pur Contr	(2,036,667)	(2,036,667)	0	0
	Interest LTD IPC	**(2,036,667)**	**(2,036,667)**	**-**	**-**
4300001	Interest Exp - Assoc Non-CBP	(841,257)	(841,257)	0	0
	Interest LTD Notes Payable - Affiliated	**(841,257)**	**(841,257)**	**-**	**-**
	Interest LTD Notes Payable - NonAffiliated	**-**	**-**	**-**	**-**
	Interest LTD Debentures	**-**	**-**	**-**	**-**
4270006	Int on LTD - Sen Unsec Notes	(38,379,167)	(38,379,167)	0	0
	Interest LTD Senior Unsecured	**(38,379,167)**	**(38,379,167)**	**-**	**-**
	Interest LTD Other - Affil	**-**	**-**	**-**	**-**
4270005	Int on LTD - Other LTD	(6,470,884)	(6,470,884)	0	0
	Interest LTD Other - NonAffil	**(6,470,884)**	**(6,470,884)**	**-**	**-**
	Interest on Long-Term Debt	**(47,727,974)**	**(47,727,974)**	**-**	**-**

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American Electric Power

INCOME STATEMENT

IS8016
YTD Aug 2024
09/09/2024 23:42

Layout: IS8016

17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol IS8016 Actual YTD Aug 2024	Kentucky Power Company - Distribution 110 Actual YTD Aug 2024	Kentucky Power Company - Generation 117 Actual YTD Aug 2024	Kentucky Power Company - Transmission 180 Actual YTD Aug 2024
4300003	Int to Assoc Co - CBP	(2,488,728)	28,191,426	(39,266,717)	8,586,563
	Interest STD - Affil	**(2,488,728)**	**28,191,426**	**(39,266,717)**	**8,586,563**
4310007	Lines Of Credit	(447,629)	(202,409)	(161,747)	(83,473)
	Interest STD - NonAffil	**(447,629)**	**(202,409)**	**(161,747)**	**(83,473)**
	Interest on Short Term Debt	**(2,936,357)**	**27,989,017**	**(39,428,464)**	**8,503,090**
4280002	Amrtz Debt Dscnt&Exp-Instl Pur	(114,334)	(114,334)	0	0
4280003	Amrtz Debt Dscnt&Exp-N/P	(8,369)	(8,369)	0	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	(399,926)	(399,926)	0	0
	Amort of Debt Disc. Prem & Exp	**(522,629)**	**(522,629)**	**-**	**-**
4281004	Amrtz Loss Rcquired Debt-Dbnt	(22,434)	(22,434)	0	0
	Amort Loss on Reacquired Debt	**(22,434)**	**(22,434)**	**-**	**-**
	Amort Gain on Reacquired Debt	**-**	**-**	**-**	**-**
	Other Interest - Fuel Recovery	**-**	**-**	**-**	**-**
4310001	Other Interest Expense	7,314,570	16,215	7,289,152	9,203
4310002	Interest on Customer Deposits	(1,350,867)	(1,350,867)	0	0
9310005	Int on Regulated Fin Leases	(7,349)	0	0	0
	Other Interest - NonAffil	**5,956,354**	**(1,334,652)**	**7,289,152**	**9,203**
	Other Interest Expense - Affil	**-**	**-**	**-**	**-**
	Interest Rate Hedge Unrealized (Gain)/Loss	**-**	**-**	**-**	**-**
4320000	Allw Brrwed Fnds Used Cnstr-Cr	2,437,463	620,954	532,065	1,284,444
	AFUDC-Borrowed Funds	**2,437,463**	**620,954**	**532,065**	**1,284,444**
	Total Interest Charges	**(42,815,577)**	**(20,997,718)**	**(31,607,247)**	**9,796,737**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**25,984,072**	**(15,277,261)**	**(58,343,039)**	**99,604,371**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	7,914,089	(6,196,504)	(9,445,566)	23,556,159
4092001	Inc Tax, Oth Inc&Ded-Federal	(278,621)	(229,722)	(47,981)	(919)
	Federal Current Income Tax	**7,635,468**	**(6,426,226)**	**(9,493,547)**	**23,555,240**
4101001	Prov Def I/T Util Op Inc-Fed	32,972,384	7,771,189	26,501,753	(1,300,559)
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(35,448,981)	(3,924,750)	(29,706,983)	(1,817,248)
	Federal Deferred Income Tax	**(2,476,597)**	**3,846,439**	**(3,205,229)**	**(3,117,806)**
	Federal Investment Tax Credits	**-**	**-**	**-**	**-**
	Federal Income Taxes	**5,158,871**	**(2,579,786)**	**(12,698,776)**	**20,437,434**
409100223	Income Taxes UOI - State	(255,377)	(1,814,309)	(2,126,994)	3,685,926
409200223	Inc Tax Oth Inc Ded - State	(69,925)	(57,653)	(12,042)	(231)
	State Current Income Tax	**(325,303)**	**(1,871,963)**	**(2,139,035)**	**3,685,695**
4111002	Prv Def I/T-Cr UtilOpInc-State	(264,082)	0	(264,082)	0
	State Deferred Income Tax	**(264,082)**	**-**	**(264,082)**	**-**
	State Investment Tax Credits	**-**	**-**	**-**	**-**
	State Income Taxes	**(589,385)**	**(1,871,963)**	**(2,403,117)**	**3,685,695**
	Local Current Income Tax	**-**	**-**	**-**	**-**
	Local Deferred Income Tax	**-**	**-**	**-**	**-**
	Local Investment Tax Credits	**-**	**-**	**-**	**-**
	Local Income Taxes	**-**	**-**	**-**	**-**
	Foreign Current Income Tax	**-**	**-**	**-**	**-**
	Foreign Deferred Income Tax	**-**	**-**	**-**	**-**
	Foreign Investment Tax Credits	**-**	**-**	**-**	**-**
	Foreign Income Taxes	**-**	**-**	**-**	**-**
	Total Income Taxes	**4,569,487**	**(4,451,749)**	**(15,101,893)**	**24,123,129**
	Equity Earnings of Subs	**-**	**-**	**-**	**-**

American Electric Power

IS8016 YTD Aug 2024 09/09/2024 23:42	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	21,414,585	(10,825,512)	(43,241,146)	75,481,243
	Discontinued Operations (Net of Taxes)	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-
	NET INCOME	21,414,585	(10,825,512)	(43,241,146)	75,481,243
	Minority Interest	-	-	-	-
	Preferred Stock Dividend Subs	-	-	-	-
	Earnings to Common Shareholders	21,414,585	(10,825,512)	(43,241,146)	75,481,243
	NET INCOME (LOSS) NODE before PS	21,414,585	(10,825,512)	(43,241,146)	75,481,243

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BS8216 YTD Aug 2024 09/11/2024 13:58	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024
	ASSETS				
	Cash and Cash Equivalents	**1,102,110**	**1,102,110**	**0**	**0**
	Other Cash Deposits	**39,370**	**17,496**	**21,256**	**618**
	Customers	10,943,579	8,013,589	829,277	2,100,713
	Accrued Unbilled Revenues	8,370,961	8,370,961	0	0
	Miscellaneous Accounts Receivable	15,341,544	4,454,402	56,596,985	17,758,065
	Allowances for Uncollectible Accounts	(844)	(810)	(6)	(29)
	Accounts Receivable	**34,655,240**	**20,838,143**	**57,426,256**	**19,858,749**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**84,989,552**	**6,508,219**	**75,426,198**	**3,055,135**
	Risk Management Contracts - Current	**10,558,719**	**0**	**10,558,719**	**0**
	Margin Deposits	**3,487,109**	**50,109**	**3,437,000**	**0**
	Unrecovered Fuel - Current	**9,032,105**	**0**	**9,032,105**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**3,767,268**	**2,855,812**	**643,122**	**268,334**
	TOTAL CURRENT ASSETS	**147,631,474**	**31,371,889**	**156,544,657**	**23,182,836**
	Electric Production	**1,263,026,069**	**1,289,806,568**	**1,299,132,590**	**871,289,462**
	Electric Transmission	**866,695,928**	**0**	**0**	**0**
	Electric Distribution	**1,156,200,249**	**0**	**0**	**0**
	General Property, Plant and Equipment	**175,463,909**	**83,276**	**(45,138)**	**1,119,396**
	Construction Work-in-Progress	**192,904,696**	**60,588,232**	**26,449,470**	**105,866,994**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,654,290,850**	**1,350,478,076**	**1,325,536,922**	**978,275,852**
	less: Accumulated Depreciation and Amortization	**(1,240,981,678)**	**(329,335,141)**	**(646,662,778)**	**(264,983,759)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,413,309,172**	**1,021,142,935**	**678,874,145**	**713,292,093**
	Net Regulatory Assets	**601,323,583**	**130,406,901**	**461,814,217**	**9,102,464**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Assets	**26,302,716**	**13,759,050**	**11,769,350**	**774,316**
	Other Non Current Assets	**35,807,155**	**8,899,262**	**23,123,571**	**3,784,323**
	TOTAL OTHER NON-CURRENT ASSETS	**663,433,455**	**153,065,212**	**496,707,139**	**13,661,103**
	TOTAL ASSETS	**3,224,374,101**	**1,205,580,036**	**1,332,125,941**	**750,136,033**
	LIABILITIES				
	Accounts Payable	**94,492,259**	**89,742,115**	**52,780,760**	**15,437,293**
	Advances from Affiliates	**73,432,524**	**(720,593,515)**	**1,051,920,025**	**(257,893,987)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**215,000,000**	**215,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	6,538,343	38,610	6,499,733	0
2440021	S/T Liability MTM Collateral	(2,187,411)	(38,610)	(2,148,801)	0
	Risk Management Liabilities - MTM	4,350,932	0	4,350,932	0
	Risk Management Liabilities	**4,350,932**	**0**	**4,350,932**	**0**
	Accrued Taxes	**33,988,984**	**(806,768)**	**(33,742,872)**	**68,538,624**
	Memo: Property Taxes	36,042,194	19,747,640	5,157,938	11,136,616
	Accrued Interest	**21,360,239**	**21,360,239**	**0**	**0**
	Risk Management Collateral	496,705	0	496,705	0
	Utility Customer Deposits	37,488,518	37,488,518	0	0
	Deposits - Customer and Collateral	**37,985,223**	**37,488,518**	**496,705**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**

BS8216 YTD Aug 2024 09/11/2024 13:58	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	130,146	49,656	80,490	0
	Obligations under Operating Leases - Current	268,616	135,317	62,668	70,632
	Tax Collections Payable	2,410,458	2,410,458	0	0
	Revenue Refunds - Accrued	416,574	0	139,349	277,225
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	928,556	819,854	99,237	9,465
	Accrued Rents	(5,525)	(5,525)	0	0
	Accrued ICP	1,263,867	1,159,390	99,080	5,398
	Accrued Vacations	2,308,724	2,063,714	224,017	20,992
	Misc Employee Benefits	1,233,172	1,044,619	186,793	1,760
	Payroll Deductions	93,801	82,902	9,635	1,264
	Severance / SEI	162,833	162,833	0	0
	Accrued Workers Compensation	190,148	190,068	80	0
2530022	Customer Advance Receipts	2,393,353	2,393,353	0	0
	Customer Advance	2,393,353	2,393,353	0	0
2420511	Control Cash Disburse Account	1,512,530	1,512,530	0	0
	Control Cash Disbursement Account	1,512,530	1,512,530	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	118,665	0	118,665	0
2300002	ARO - Current	1,442,506	0	1,442,506	0
2420088	Econ. Development Fund Curr	525,836	525,836	0	0
2420512	Unclaimed Funds	21,503	21,503	0	0
2420542	Acc Cash Franchise Req	60,149	60,149	0	0
2420643	Accrued Audit Fees	54,246	22,785	20,504	10,957
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	431,197	430,212	0	985
2530112	Other Deferred Credits-Curr	3,380	3,380	0	0
2530124	Contr In Aid of Constr Advance	250,470	250,470	0	0
	Misc Current and Accrued Liabilities	2,908,636	1,315,020	1,581,674	11,942
	Current Other and Accrued Liabilities	15,817,126	13,149,215	2,339,866	328,046
	Other Current Liabilities	**16,215,889**	**13,334,188**	**2,483,023**	**398,677**
	TOTAL CURRENT LIABILITIES	**496,826,050**	**(344,475,222)**	**1,078,288,573**	**(173,519,393)**
	Long-Term Debt - Affiliated	**0**	**0**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,060,867,506**	**1,060,867,506**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(615,313)**	**(615,313)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,060,252,194*	*1,060,252,194*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	1,235,362	11,352	1,224,010	0
2440022	L/T Liability MTM Collateral	(11,352)	(11,352)	0	0
	Long-Term Risk Management Liabilities - MTM	1,224,010	0	1,224,010	0
	Long-Term Risk Management Liabilities	**1,224,010**	**0**	**1,224,010**	**0**
	Deferred Income Taxes	**476,453,547**	**168,273,074**	**219,428,906**	**88,751,567**
	Deferred Investment Tax Credits	**0**	**0**	**0**	**0**
	Regulatory Liabilities and Deferred Credits	**111,720,514**	**82,133,058**	**(3,527,351)**	**33,114,807**
	Memo - Reg Liab and Def ITC	*111,720,514*	*82,133,058*	*(3,527,351)*	*33,114,807*
	Asset Retirement Obligation	**86,037,279**	**211,161**	**85,826,118**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**7,610,190**	**11,210,735**	**(5,364,719)**	**1,764,174**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redem	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	741,848	563,077	178,771	0
	Obligations Under Operating Leases	1,680,771	1,182,720	194,621	303,429
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0

BS8216 YTD Aug 2024 09/11/2024 13:58	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024	YTD Aug 2024
	Customer Advances for Construction	99,203	99,203	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	30,730	30,730	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	370	0	0	370
2530175	Legal Contingencies	(549)	(549)	0	0
2530185	O\U Accounting of ExpensesT	7,873	0	7,873	0
2530188	Long Term Assoc AP	3,895,327	0	0	3,895,327
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	4,018,367	30,181	7,873	3,980,313
	Total Other Deferred Credits	4,117,570	129,384	7,873	3,980,313
	Accumulated Provisions - Rate Refund	709,227	0	0	709,227
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**7,249,416**	**1,875,182**	**381,265**	**4,992,969**
	TOTAL NON-CURRENT LIABILITIES	**1,750,547,148**	**1,323,955,404**	**297,968,228**	**128,623,516**
	TOTAL LIABILITIES	**2,247,373,198**	**979,480,181**	**1,376,256,801**	**(44,895,877)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**527,602,081**	**106,025,371**	**336,884,757**	**84,691,953**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**398,948,822**	**97,670,434**	**(391,303,221)**	**692,581,609**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**977,000,903**	**226,099,854**	**(44,130,861)**	**795,031,910**
	Memo: Total Equity	977,000,903	226,099,854	(44,130,861)	795,031,910
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,224,374,101**	**1,205,580,036**	**1,332,125,941**	**750,136,033**

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BS8216 YTD Aug 2023 09/12/2023 13:28	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Aug 2023	YTD Aug 2023	YTD Aug 2023	YTD Aug 2023
	ASSETS				
	Cash and Cash Equivalents	**1,350,600**	**1,350,600**	**0**	**0**
	Other Cash Deposits	**55,764**	**22,325**	**32,470**	**969**
	Customers	36,583,315	36,364,411	(263,015)	481,919
	Accrued Unbilled Revenues	19,656,475	19,656,475	0	0
	Miscellaneous Accounts Receivable	15,030,638	2,440,269	49,384,656	16,501,376
	Allowances for Uncollectible Accounts	(605,630)	(603,885)	0	(1,745)
	Accounts Receivable	**70,664,799**	**57,857,270**	**49,121,641**	**16,981,550**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**83,365,835**	**8,229,362**	**72,481,975**	**2,654,498**
	Risk Management Contracts - Current	**7,739,919**	**0**	**7,739,919**	**0**
	Margin Deposits	**1,223,720**	**0**	**1,223,720**	**0**
	Unrecovered Fuel - Current	**7,379,130**	**0**	**7,379,130**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**3,415,501**	**2,565,023**	**602,243**	**248,235**
	TOTAL CURRENT ASSETS	**175,195,268**	**70,024,580**	**138,581,098**	**19,885,251**
	Electric Production	**1,241,595,081**	**1,225,756,815**	**1,280,803,100**	**821,156,828**
	Electric Transmission	**817,364,492**	**0**	**0**	**0**
	Electric Distribution	**1,095,549,310**	**0**	**0**	**0**
	General Property, Plant and Equipment	**174,434,740**	**83,276**	**24,208**	**1,119,396**
	Construction Work-in-Progress	**167,758,938**	**63,100,649**	**23,733,277**	**80,925,011**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,496,702,560**	**1,288,940,740**	**1,304,560,586**	**903,201,234**
	less: Accumulated Depreciation and Amortization	**(1,189,802,982)**	**(315,824,875)**	**(621,891,399)**	**(252,086,708)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,306,899,579**	**973,115,865**	**682,669,187**	**651,114,527**
	Net Regulatory Assets	**520,060,409**	**124,827,692**	**388,541,462**	**6,691,255**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**179,490**	**0**	**179,490**	**0**
	Employee Benefits and Pension Assets	**22,007,002**	**11,566,652**	**9,878,154**	**562,195**
	Other Non Current Assets	**22,652,808**	**6,564,140**	**13,971,643**	**2,117,026**
	TOTAL OTHER NON-CURRENT ASSETS	**564,899,709**	**142,958,484**	**412,570,748**	**9,370,476**
	TOTAL ASSETS	**3,046,994,555**	**1,186,098,929**	**1,233,821,034**	**680,370,254**
	LIABILITIES				
	Accounts Payable	**88,516,283**	**79,771,492**	**53,293,523**	**8,746,930**
	Advances from Affiliates	**126,284,933**	**(646,918,142)**	**945,649,419**	**(172,446,344)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**425,000,000**	**425,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	1,834,379	0	1,834,379	0
2440021	S/T Liability MTM Collateral	(270)	0	(270)	0
	Risk Management Liabilities - MTM	1,834,109	0	1,834,109	0
	Risk Management Liabilities	**1,834,109**	**0**	**1,834,109**	**0**
	Accrued Taxes	**25,012,049**	**9,695,492**	**(14,551,607)**	**29,868,164**
	Memo: Property Taxes	24,328,097	15,151,596	3,805,681	5,370,820

BS8216 YTD Aug 2023 09/12/2023 13:28	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Aug 2023	YTD Aug 2023	YTD Aug 2023	YTD Aug 2023
	Accrued Interest	**16,792,298**	**16,792,298**	**0**	**0**
	Risk Management Collateral	209,262	0	209,262	0
	Utility Customer Deposits	40,398,661	40,398,661	0	0
	Deposits - Customer and Collateral	**40,607,923**	**40,398,661**	**209,262**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	76,369	0	76,369	0
	Obligations under Operating Leases - Current	123,313	58,725	60,431	4,157
	Tax Collections Payable	2,086,939	2,086,939	0	0
	Revenue Refunds - Accrued	110,438	0	110,438	(0)
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	917,719	816,979	92,630	8,110
	Accrued Rents	0	0	0	0
	Accrued ICP	1,730,202	1,605,443	118,197	6,562
	Accrued Vacations	2,669,796	2,343,372	303,504	22,920
	Misc Employee Benefits	1,651,389	870,691	778,781	1,917
	Payroll Deductions	119,553	93,701	24,580	1,272
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	212,295	192,621	19,674	0
2530022	Customer Advance Receipts	4,383,926	4,383,926	0	0
	Customer Advance	4,383,926	4,383,926	0	0
2420511	Control Cash Disburse Account	1,333,463	1,333,463	0	0
	Control Cash Disbursement Account	1,333,463	1,333,463	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	111,171	0	111,171	0
2300002	ARO - Current	29,797	0	29,797	0
2420088	Econ. Development Fund Curr	333,020	333,020	0	0
2420512	Unclaimed Funds	7,541	7,541	0	0
2420542	Acc Cash Franchise Req	53,375	53,375	0	0
2420643	Accrued Audit Fees	152,400	62,832	59,215	30,352
2420656	Federal Mitigation Accru (NSR)	244,045	0	244,045	0
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	452,601	451,519	0	1,082
2530112	Other Deferred Credits-Curr	154,583	154,583	0	0
2530124	Contr In Aid of Constr Advance	240,507	240,507	0	0
2530177	Deferred Rev-Bonus Lease Curr	13,281	0	13,281	0
	Misc Current and Accrued Liabilities	1,793,006	1,304,062	457,509	31,435
	Current Other and Accrued Liabilities	17,008,727	15,031,197	1,905,313	72,216
	Other Current Liabilities	**17,208,409**	**15,089,922**	**2,042,113**	**76,373**
	TOTAL CURRENT LIABILITIES	**741,256,003**	**(60,170,277)**	**988,476,819**	**(133,754,876)**
	Long-Term Debt - Affiliated	**25,000,000**	**25,000,000**	**0**	**0**
	Long-Term Debt - Non Affiliated	**753,353,196**	**753,353,196**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**0**	**0**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*753,353,196*	*753,353,196*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	313,797	0	313,797	0
2440022	L/T Liability MTM Collateral	(132)	0	(132)	0
	Long-Term Risk Management Liabilities - MTM	313,665	0	313,665	0
	Long-Term Risk Management Liabilities	**313,665**	**0**	**313,665**	**0**

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BS8216 YTD Aug 2023 09/12/2023 13:28	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Aug 2023	YTD Aug 2023	YTD Aug 2023	YTD Aug 2023
	Deferred Income Taxes	**463,634,474**	**156,212,560**	**217,160,698**	**90,261,215**
	Deferred Investment Tax Credits	**(0)**	**0**	**(0)**	**0**
	Regulatory Liabilities and Deferred Credits	**94,968,629**	**63,711,925**	**4,157,495**	**27,099,209**
	Memo - Reg Liab and Def ITC	*94,968,629*	*63,711,925*	*4,157,495*	*27,099,209*
	Asset Retirement Obligation	**18,441,535**	**196,470**	**18,245,065**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**8,007,217**	**10,960,005**	**(4,516,015)**	**1,563,226**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redemption	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	237,551	0	237,551	0
	Obligations Under Operating Leases	429,792	203,299	226,492	0
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	106,102	106,102	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	44,663	44,663	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	1,258	0	0	1,258
2530185	O\U Accounting of ExpensesT	2,288	0	2,288	0
2530188	Long Term Assoc AP	2,125,478	0	611,274	1,514,204
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	2,258,303	44,663	613,562	1,600,078
	Total Other Deferred Credits	2,364,405	150,765	613,562	1,600,078
	Accumulated Provisions - Rate Refund	1,798,579	0	37,950	1,760,629
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**4,830,327**	**354,065**	**1,115,555**	**3,360,707**
	TOTAL NON-CURRENT LIABILITIES	**1,368,549,043**	**1,009,788,221**	**236,476,464**	**122,284,357**
	TOTAL LIABILITIES	**2,109,805,046**	**949,617,944**	**1,224,953,283**	**(11,470,519)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,235,187**	**106,025,371**	**336,070,072**	**84,139,743**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**360,504,322**	**108,051,565**	**(337,489,924)**	**589,942,682**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**937,189,509**	**236,480,985**	**8,867,751**	**691,840,773**
	Memo: Total Equity	937,189,509	236,480,985	8,867,751	691,840,773
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,046,994,555**	**1,186,098,929**	**1,233,821,034**	**680,370,254**

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KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - August, 2024

Final

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		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,276,923,610.03	30,783,810.47	(9,173,705.46)	0.00	0.00	1,298,533,715.04
101/106	CLOUD GENERATION	381,874.02	41,522.51	0.00	0.00	0.00	423,396.53
	TOTAL PRODUCTION	**1,277,305,484.05**	**30,825,332.98**	**(9,173,705.46)**	**0.00**	**0.00**	**1,298,957,111.57**
101/106	TRANSMISSION	842,600,699.05	31,163,506.71	(2,474,743.30)	0.00	0.00	871,289,462.46
101/106	CLOUD TRANSMISSION	201,394.70	67,732.29	0.00	0.00	0.00	269,126.99
101/106	DISTRIBUTION	1,249,889,192.92	47,324,580.03	(8,855,909.70)	0.00	0.00	1,288,357,863.25
101/106	CLOUD DISTRIBUTION	1,618,196.01	295,742.97	0.00	0.00	0.00	1,913,938.98
	TOTAL (ACCOUNTS 101 & 106)	**3,371,614,966.73**	**109,676,894.98**	**(20,504,358.46)**	**0.00**	**0.00**	**3,460,787,503.25**
1011001/12	CAPITAL LEASES	1,080,445.85	0.00	0.00	165,462.51	0.00	1,245,908.36
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**3,372,695,412.58**	**109,676,894.98**	**(20,504,358.46)**	**165,462.51**	**0.00**	**3,462,033,411.61**
1050001	PLANT HELD FOR FUTURE USE	801,671.21	0.00	0.00	0.00	0.00	801,671.21
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEGINNING BALANCE	159,612,262.17					
107000X	ADDITIONS		119,835,658.58				
107000X	TRANSFERS		(86,543,225.01)				
107000X	ENDING BALANCE		33,292,433.57				192,904,695.74
107000X	**CLOUD CONSTRUCTION WIP:**						
107000X	BEGINNING BALANCE	1,540,647.27					
107000X	ADDITIONS		657,316.24				
107000X	TRANSFERS		(404,997.77)				
107000X	ENDING BALANCE		252,318.47				1,792,965.74
	TOTAL ELECTRIC UTILITY PLANT	**3,534,649,993.23**	**143,221,647.02**	**(20,504,358.46)**	**165,462.51**	**0.00**	**3,657,532,744.30**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	571,711.48	0.00	(69,345.76)	0.00	0.00	502,365.72
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1210003	NONUTILITY PROPERTY-WIP						
	BEGINNING BALANCE	0.00					
	ADDITIONS		0.00				
	TRANSFERS		0.00				
	ENDING BALANCE		0.00				0.00
1210016	NONUTILITY PROPERTY-CCNC	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	655,168.37	0.00	0.00	0.00	0.00	655,168.37
	TOTAL NONUTILITY PLANT	**1,226,879.85**	**0.00**	**(69,345.76)**	**0.00**	**0.00**	**1,157,534.09**

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KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - August, 2024

Final

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		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
.	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	623,339,018.27	25,276,279.36	(7,510,950.59)	(4,110,785.46)	(4,118,311.49)	632,875,250.09
1080001/11	TRANSMISSION	284,929,166.47	15,848,762.28	(1,961,176.37)	(54,498.82)	0.00	298,762,253.56
1080001/11	DISTRIBUTION	376,851,080.91	29,782,879.03	(7,114,439.16)	(2,906,943.96)	(152,964.97)	396,459,611.85
1080013	PRODUCTION	(4,098,119.71)	0.00	0.00	0.00	4,098,119.71	0.00
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(151,934.59)	0.00	0.00	0.00	151,934.59	0.00
	RETIREMENT WORK IN PROGRESS	(13,358,319.70)	0.00	0.00	(7,398,491.59)	7,072,228.24	(13,684,583.05)
	TOTAL (108X accounts)	**1,267,510,891.66**	**70,907,920.67**	**(16,586,566.12)**	**(14,470,719.83)**	**7,051,006.08**	**1,314,412,532.46**
	NUCLEAR					0.00	
1110001	PRODUCTION	12,296,619.11	2,294,489.08	(1,662,754.87)	0.00	0.00	12,928,353.32
1110007	CLOUD IMPLEMENT COST PRODUCTI	103,001.61	53,323.92	0.00	0.00	0.00	156,325.53
1110001	TRANSMISSION	4,150,582.38	1,048,732.98	(513,566.93)	0.00	0.00	4,685,748.43
1110007	CLOUD IMPLEMENT COST TRANSMIS	36,477.38	31,088.68	0.00	0.00	0.00	67,566.06
1110001	DISTRIBUTION	14,363,824.54	3,209,655.20	(1,741,470.54)	0.00	0.00	15,832,009.20
1110007	CLOUD IMPLEMENT COST DISTRIBUT	417,883.25	200,934.00	0.00	0.00	0.00	618,817.25
	TOTAL (111X accounts)	**31,368,388.27**	**6,838,223.86**	**(3,917,792.34)**	**0.00**	**0.00**	**34,288,819.79**
1011006	CAPITAL LEASES	291,805.66	0.00	0.00	0.00	80,531.06	372,336.72
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**1,299,171,085.59**	**77,746,144.53**	**(20,504,358.46)**	**(14,470,719.83)**	**7,131,537.14**	**1,349,073,688.97**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	172,262.12	4,446.52	(69,345.76)	69,987.88	0.00	177,350.76
1220002	Depr&Amrt of Nonutl Prop-Leasd	0.00	0.00	0.00	0.00	0.00	0.00
1220003	Depr&Amrt of Nonutl Prop-WIP	69,987.88	0.00	0.00	0.00	(69,987.88)	0.00
1220004	Depletion - Owned	0.00	0.00	0.00	0.00	0.00	0.00
1240027	Other Property - RWIP	35,121.36	0.00	0.00	0.00	0.00	35,121.36
1240028	Other Property - Retirement	(46,947.27)	0.00	0.00	0.00	0.00	(46,947.27)
	TOTAL NONUTILITY PLANT	**230,424.09**	**4,446.52**	**(69,345.76)**	**69,987.88**	**(69,987.88)**	**165,524.85**

U.S. Department of Energy Energy Information Administration Form EIA-826	**Monthly Electric Utility Sales and Revenue Report with State Distributions – 2024**	Form Approval OMB NO.1905-0129 (Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**

Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650.

Utility Name: Kentucky Power Company **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan___ Feb___ Mar___ Apr___ May___ Jun___ Jul___ Aug_X__ Sep___ Oct___ Nov___ Dec__ , 2024

Contact Person: Sandra Vargo	**Phone number: 614-716-2671**
Email: slvargo@aep.com	**Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	25,494	17,635	14,695	-	57,823
	b. Megwatthours	164,621	129,418	174,219	-	468,258
	c. Number of consumers	130,759.0	30,699	954	-	162,412
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					

Note:

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October 30th, 2024

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed September 2024 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:

1-12	Income Statement
1-3	Details of Operating Revenues
5-10	Operating Expenses – Functional Expenses
12	Detail Statement of Taxes

Balance Sheet:

13	Balance Sheet – Assets & Other Debits
13-15	Balance Sheet – Liabilities & Other Credits
14-15	Deferred Credits
15	Statement of Retained Earnings

Utility Property:

16-17	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Digitally signed by Brian J. Frantz
DN: cn=Brian J. Frantz, c=US, o=AEP, ou=Corporate Accounting, email=bjfrantz@aep.com
Reason: I have reviewed this document
Date: 2024.10.30 08:24:47 -04'00'

Brian J Frantz
Director - Corporate Accounting

American Electric Power

INCOME STATEMENT

IS8016
YTD Sep 2024
10/18/2024 15:50

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Sep 2024	Kentucky Power Company - Distribution 110 Actual YTD Sep 2024	Kentucky Power Company - Generation 117 Actual YTD Sep 2024	Kentucky Power Company - Transmission 180 Actual YTD Sep 2024
		REVENUES				
4400001		Residential Sales-W/Space Htg	105,391,240	105,391,240	0	0
4400002		Residential Sales-W/O Space Ht	49,372,546	50,163,994	(791,448)	0
4400005		Residential Fuel Rev	54,090,949	54,090,949	0	0
	A	**Revenue - Residential Sales**	**208,854,735**	**209,646,184**	**(791,448)**	**-**
4420001		Commercial Sales	73,995,374	74,616,799	(621,424)	0
4420006		Sales to Pub Auth - Schools	11,748,799	11,748,799	0	0
4420007		Sales to Pub Auth - Ex Schools	14,584,267	14,584,267	0	0
4420013		Commercial Fuel Rev	41,174,537	41,174,537	0	0
	A	**Revenue - Commercial Sales**	**141,502,978**	**142,124,403**	**(621,424)**	**-**
	B	**Revenue - Industrial Sales - Affiliated**	**-**	**-**	**-**	**-**
4420002		Industrial Sales (Excl Mines)	54,157,058	55,071,770	(914,712)	0
4420004		Ind Sales-NonAffil(Incl Mines)	13,480,822	13,480,822	0	0
4420016		Industrial Fuel Rev	56,791,332	56,791,332	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**124,429,212**	**125,343,924**	**(914,712)**	**-**
		Revenue - Industrial Sales	**124,429,212**	**125,343,924**	**(914,712)**	**-**
	A	**Revenue - Gas Products Sales**	**-**	**-**	**-**	**-**
	A	**Revenue - Gas Transportation & Storage Sales**	**-**	**-**	**-**	**-**
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	**-**	**-**	**-**	**-**
4440000		Public Street/Highway Lighting	1,343,635	1,347,249	(3,615)	0
4440002		Public St & Hwy Light Fuel Rev	239,652	239,652	0	0
	A	**Revenue - Other Retail Sales**	**1,583,286**	**1,586,901**	**(3,615)**	**-**
	B	**Revenue - Other Retail Sales - Affiliated**	**-**	**-**	**-**	**-**
		Revenue - Retail Sales	**476,370,213**	**478,701,411**	**(2,331,199)**	**-**
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	61,479,638
4561033		PJM NITS Revenue - Affiliated	55,195,441	0	0	55,195,441
4561034		PJM TO Adm. Serv Rev - Aff	190,542	0	0	190,542
4561035		PJM Affiliated Trans NITS Cost	(45,495,202)	0	(45,495,202)	0
4561036		PJM Affiliated Trans TO Cost	(124,880)	0	(124,880)	0
4561059		Affil PJM Trans Enhancmnt Rev	1,172,263	0	0	1,172,263
4561060		Affil PJM Trans Enhancmnt Cost	(966,245)	0	(966,245)	0
4561062		PROVISION RTO Cost - Affi	655,596	0	655,596	0
4561063		PROVISION RTO Rev Affiliated	2,719,399	0	0	2,719,399
	B	**Revenue - Transmission-Affiliated**	**13,346,914**	**-**	**(45,930,731)**	**120,757,283**
4470150		Transm. Rev.-Dedic. Whlsl/Muni	126,744	0	(1,941,997)	2,068,741
4470206		PJM Trans loss credits-OSS	67,479	0	67,479	0
4470209		PJM transm loss charges-OSS	(172,535)	0	(172,535)	0
4561005		PJM Point to Point Trans Svc	1,647,976	0	1,647,976	0
4561006		PJM Trans Owner Admin Rev	68,123	0	0	68,123
4561007		PJM Network Integ Trans Svc	8,289,827	0	0	8,289,827
4561019		Oth Elec Rev Trans Non Affil	39,627	0	0	39,627
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	3,841	0	0	3,841
4561029		PJM NITS Revenue Whsl Cus-NAff	1,854,053	0	0	1,854,053
4561030		PJM TO Serv Rev Whls Cus-NAff	7,003	0	0	7,003
4561045		PJM Non-Aff Gen IPP Rev	5,982	0	0	5,982
4561058		NonAffil PJM Trans Enhncmt Rev	1,288,572	0	0	1,288,572
4561061		NAff PJM RTEP Rev for Whsl-FR	39,377	0	0	39,377
4561064		PROVISION RTO Rev WhslCus-NAf	91,491	0	0	91,491
4561065		PROVISION RTO Rev - NonAff	398,118	0	(1)	398,119
	A	**Revenue - Transmission-NonAffiliated**	**13,755,678**	**-**	**(399,078)**	**14,154,757**
		Revenue - Transmission	**27,102,592**	**-**	**(46,329,809)**	**134,912,039**

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American Electric Power

INCOME STATEMENT

IS8016
YTD Sep 2024
10/18/2024 15:50

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Sep 2024	Kentucky Power Company - Distribution 110 Actual YTD Sep 2024	Kentucky Power Company - Generation 117 Actual YTD Sep 2024	Kentucky Power Company - Transmission 180 Actual YTD Sep 2024
	B	**Revenue - Resale-Affiliated**	-	-	-	-
4470010		Sales for Resale-Bookout Purch	(19)	0	(19)	0
4470027		Whsal/Muni/Pb Ath Fuel Rev	1,862,376	0	1,862,376	0
4470033		Whsal/Muni/Pub Auth Base Rev	1,329,853	0	1,329,853	0
4470082		Financial Electric Realized	(4,729)	0	(4,729)	0
4470089		PJM Energy Sales Margin	368,340	0	368,340	0
4470098		PJM Oper.Reserve Rev-OSS	(36,177)	0	(36,177)	0
4470099		Capacity Cr. Net Sales	(41,041)	0	(41,041)	0
4470100		PJM FTR Revenue-OSS	155,518	0	155,518	0
4470103		PJM Energy Sales Cost	10,288,270	0	10,288,270	0
4470110		PJM TO Admin. Exp.-NonAff.	4	0	4	0
4470115		PJM Meter Corrections-OSS	42,209	0	42,209	0
4470116		PJM Meter Corrections-LSE	284,658	0	284,658	0
4470126		PJM Incremental Imp Cong-OSS	(298,833)	0	(298,833)	0
4470175		OSS Sharing Reclass - Retail	3,756,178	0	3,756,178	0
4470176		OSS Sharing Reclass-Reduction	(3,756,178)	0	(3,756,178)	0
4470215		PJM 30m Suppl Reserve CH OSS	2,731	0	2,731	0
4470220		PJM Regulation - OSS	3,672,714	0	3,672,714	0
4470221		PJM Spinning Reserve - OSS	45,241	0	45,241	0
5550080		PJM Hourly Net Purch.-FERC	(5,827,513)	0	(5,827,513)	0
	A	**Revenue - Resale-NonAffiliated**	**11,843,602**	**-**	**11,843,602**	**-**
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**11,843,602**	**-**	**11,843,602**	**-**
4470074		Sale for Resale-Aff-Trnf Price	0	0	313,684,246	0
4540001		Rent From Elect Property - Af	866,492	688,533	0	368,766
	B	**Revenue - Other Ele-Affilliated**	**866,492**	**688,533**	**313,684,246**	**368,766**
4500000		Forfeited Discounts	656,987	656,987	0	0
4510001		Misc Service Rev - Nonaffil	100,316	99,650	0	666
4540002		Rent From Elect Property-NAC	2,610,918	2,175	2,589,468	19,275
4540005		Rent from Elec Prop-Pole Attch	3,753,430	3,747,664	0	5,766
4560007		Oth Elect Rev - DSM Program	359,713	359,713	0	0
5010040		Gas Procuremnt Sales Net	(1,141,697)	0	(1,141,697)	0
		Revenue - Other Ele-NonAffilliated	**6,339,667**	**4,866,190**	**1,447,771**	**25,707**
		Revenue - Gas	-	-	-	-
4118002		Comp. Allow Gains Title IV SO2	14	14	0	0
4118003		Comp. Allow. Gains-Seas NOx	180,714	0	180,714	0
		Gain/(Loss) on Allowances	**180,729**	**14**	**180,714**	**-**
	A	**Revenue - Other Ele-NonAffilliated**	**6,520,396**	**4,866,204**	**1,628,485**	**25,707**
		Revenue - Other Opr Electric	**7,386,888**	**5,554,737**	**315,312,731**	**394,473**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
4170004		Rev from Non-Util Oper NonAfil	249,010	249,010	0	0
	D	**Revenues Non-Utility Operations - NonAffiliated**	**249,010**	**249,010**	-	-
		Revenues from Non-Utility Operations	**249,010**	**249,010**	-	-
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operatng Rental Income	1,025	1,025	0	0
4180005		Non-Opratng Rntal Inc-Depr	(5,002)	0	0	(5,002)
	D	**Non-Operating Rental Income - NonAffiliated**	**(3,977)**	**1,025**	-	**(5,002)**
		Non-Operating Rental Income	**(3,977)**	**1,025**	-	**(5,002)**

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American Electric Power

IS8016 YTD Sep 2024 10/18/2024 15:50		INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
		Layout: IS8016				
17A V2099-01-01		Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024
	C	**Non-Operating Misc Income -Affiliated**	-	-	-	-
4210002		Misc Non-Op Inc-NonAsc-Rents	1,375	428	692	255
4210007		Misc Non-Op Inc - NonAsc - Oth	6,690	917	5,773	0
	D	**Non-Operating Misc Income - NonAffiliated**	**8,065**	**1,345**	**6,465**	**255**
		Non-Operating Misc Income	**8,065**	**1,345**	**6,465**	**255**
4540004		Rent From Elect Prop-ABD-Nonaf	1,674	1,674	0	0
4560015		Other Electric Revenues - ABD	509,826	394,344	0	115,482
	D	**Associated Business Development Income**	**511,500**	**396,018**	**-**	**115,482**
		Revenue - Other Opr - Other	**764,598**	**647,399**	**6,465**	**110,735**
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	**-**	**-**	**-**	**-**
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***764,598***	***647,399***	***6,465***	***110,735***
		Revenue - Other Operating	**8,151,486**	**6,202,136**	**315,319,196**	**505,208**
4491002		Prov Rate Refund-Nonaffiliated	(85,899)	0	0	(85,899)
4491003		Prov Rate Refund - Retail	(18,849)	0	0	(18,849)
	A	**Provision for Rate Refund - NonAffiliated**	**(104,748)**	**-**	**-**	**(104,748)**
4491004		Prov Rate Refund - Affiliated	(552,514)	0	0	(552,514)
	B	**Provision for Rate Refund - Affiliated**	**(552,514)**	**-**	**-**	**(552,514)**
		Provision for Rate Refund	**(657,262)**	**-**	**-**	**(657,262)**
	A	**Revenue - Power Sales**	**-**	**-**	**-**	**-**
		TOTAL OPERATING REVENUES	**522,810,631**	**484,903,547**	**278,501,790**	**134,759,985**
=(A)		*Memo: G/T/D Revenue*	*508,385,141*	*483,567,615*	*10,741,810*	*14,075,715*
=(B)		*Memo: Other Affiliated Revenue*	*13,660,892*	*688,533*	*267,753,515*	*120,573,535*
=(C)		*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
=(D)		*Memo: Revenue-Oth Opr-Oth Non*	*764,598*	*647,399*	*6,465*	*110,735*
		Memo: Total Operating Revenues	*522,810,631*	*484,903,547*	*278,501,790*	*134,759,985*
=(E)=(B)+(C)		*Memo: Affiliated Revenue*	***13,660,892***	***688,533***	***267,753,515***	***120,573,535***
=(F)=(D)+(A)		*Memo: Non-Affiliated Revenue*	***509,149,739***	***484,215,014***	***10,748,275***	***14,186,450***
		Memo: Total Operating Revenues	***522,810,631***	***484,903,547***	***278,501,790***	***134,759,985***
		FUEL EXPENSES				
5010000		Fuel	5,282,328	2	5,282,324	1
5010001		Fuel Consumed	58,418,198	0	58,418,198	0
5010003		Fuel - Procure Unload & Handle	2,390,083	0	2,390,083	0
5010012		Ash Sales Proceeds	15,089	0	15,089	0
5010013		Fuel Survey Activity	49,281	0	49,281	0
5010019		Fuel Oil Consumed	2,714,540	0	2,714,540	0
5010020		Nat Gas Consumed Steam	24,588,047	0	24,588,047	0
5010021		Transp Gas Consumed Steam	601,297	0	601,297	0
5010027		Gypsum handling/disposal costs	1,014,481	0	1,014,481	0
5010028		Gypsum Sales Proceeds	(1,050,665)	0	(1,050,665)	0
5010034		Gas Transp Res Fees-Steam	4,782,239	0	4,782,239	0
		Fuel Expense Total	**98,804,918**	**2**	**98,804,914**	**1**
5010005		Fuel - Deferred	2,425,549	0	2,425,549	0
		Deferred Fuel Expense	**2,425,549**	**-**	**2,425,549**	**-**
		Over Under Fuel Expense				
		Fuel for Electric Generation	**101,230,467**	**2**	**101,230,463**	**1**
		Fuel from Affiliates for Electric Generation	**-**	**-**	**-**	**-**
5090000		Allow Consum Title IV SO2	27,499	0	27,499	0
5090001		Allowance Consumption - NOx	42,857	0	42,857	0
5090009		Allow Consumpt CSAPR SO2	132	0	132	0

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American Electric Power

INCOME STATEMENT

IS8016
YTD Sep 2024
10/18/2024 15:50

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Sep 2024	Kentucky Power Company - Distribution 110 Actual YTD Sep 2024	Kentucky Power Company - Generation 117 Actual YTD Sep 2024	Kentucky Power Company - Transmission 180 Actual YTD Sep 2024
5570009	Other Pwr Exp- REC's - RETAIL	446	0	446	0
	Allowances - Consumption	**70,934**	**-**	**70,934**	**-**
5020002	Urea Expense	909,152	0	909,152	0
5020004	Lime-Related Expenses	1,490,648	0	1,490,648	0
	Emissions Control - Chemicals	**2,399,799**	**-**	**2,399,799**	**-**
	Total Fuel for Electric Generation	**103,701,201**	**2**	**103,701,197**	**1**
	Memo: NonAff Fuel/Allow/Emissions	***103,701,201***	***2***	***103,701,197***	***1***
5550004	Purchased Power-Pool Capacity	373,078	0	373,078	0
5550029	Purch Power-Assoc-Trnsfr Price	0	313,684,246	0	0
	Purchased Electricity from AEP - Affiliates	**373,078**	**313,684,246**	**373,078**	**-**
5550001	Purch Pwr-NonTrading-Nonassoc	66,163,822	0	66,163,822	0
5550023	Purch Power Capacity -NA	814,612	0	814,612	0
5550039	PJM Inadvertent Mtr Res-OSS	5,380	0	5,380	0
5550040	PJM Inadvertent Mtr Res-LSE	57,669	0	57,669	0
5550074	PJM Reactive-Charge	2,708,591	0	2,708,591	0
5550075	PJM Reactive-Credit	(1,076,157)	0	(1,076,157)	0
5550076	PJM Black Start-Charge	811,450	0	811,450	0
5550078	PJM Regulation-Charge	461,729	0	461,729	0
5550079	PJM Regulation-Credit	(12,175)	0	(12,175)	0
5550083	PJM Sync & Non Sync-Charge	358,909	0	358,909	0
5550084	PJM Sync & Non Sync-Credit	(32,850)	0	(32,850)	0
5550123	PJM OpRes-LSE-Charge	1,022,703	0	1,021,377	1,326
5550124	PJM Implicit Congestion-LSE	4,930,434	0	4,930,434	0
5550132	PJM FTR Revenue-LSE	(5,359,953)	0	(5,359,953)	0
5550137	PJM OpRes-LSE-Credit	(56,266)	0	(56,266)	0
5550153	PurchPower-Rockport Def-NonAff	152,680	0	152,680	0
5550326	PJM Transm Loss Charges - LSE	4,215,655	0	4,215,655	0
5550327	PJM Transm Loss Credits-LSE	(1,750,495)	0	(1,750,495)	0
5550328	PJM FC Penalty Credit	(2,878)	0	(2,878)	0
	Purchased Electricity for Resale - NonAffiliated	**73,412,860**	**-**	**73,411,535**	**1,326**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**
8140000	Underground Storage Expenses	1,637	0	1,637	0
	Purchased Gas for Resale - NonAffiliated	**1,637**	**-**	**1,637**	**-**
	Total Purchased Power	**73,787,576**	**313,684,246**	**73,786,250**	**1,326**
	GROSS MARGIN	**345,321,854**	**171,219,298**	**101,014,343**	**134,758,657**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	3,531,478	(14,315)	3,538,818	6,976
5020000	Steam Expenses	1,150,294	0	1,150,294	0
5050000	Electric Expenses	30,223	0	30,223	0
5060000	Misc Steam Power Expenses	5,029,624	61,533	4,961,772	6,319
5060002	Misc Steam Power Exp-Assoc	38,901	0	38,901	0
5060004	NSR Settlement Expense	10,130	0	10,130	0
5060011	BSRR O/U Recovery-Oper Costs	367	0	367	0
	Steam Generation Op Exp	**9,791,018**	**47,218**	**9,730,505**	**13,295**
	Nuclear Generation Op Exp	**-**	**-**	**-**	**-**
	Hydro Generation Op Exp	**-**	**-**	**-**	**-**
5560000	Sys Control & Load Dispatching	49,303	0	49,303	0
5570000	Other Expenses	635,070	0	635,070	0
5570007	Other Pwr Exp - Wholesale RECs	245	245	0	0
5570010	OH Auction Exp - Incremental	6	0	6	0

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IS8016 YTD Sep 2024 10/18/2024 15:50	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024
5757000	PJM Admin-MAM&SC- OSS	57,428	0	57,428	0
5757001	PJM Admin-MAM&SC- Internal	1,080,024	0	1,080,024	0
	Other Generation Op Exp	**1,822,076**	**245**	**1,821,831**	**-**
5600000	Oper Supervision & Engineering	1,696,373	46,038	17,469	1,632,866
5612000	Load Dispatch-Mntr&Op TransSys	293,068	3,011	403	289,654
5614000	PJM Admin-SSC&DS-OSS	58,345	0	58,345	0
5614001	PJM Admin-SSC&DS-Internal	982,674	0	982,674	0
5614009	GreenHat Settlement	3,535	0	3,535	0
5615000	Reliability,Plng&Stds Develop	52,836	1,177	162	51,498
5618000	PJM Admin-RP&SDS-OSS	18,982	0	18,982	0
5618001	PJM Admin-RP&SDS- Internal	334,154	0	334,154	0
5620001	Station Expenses - Nonassoc	173,795	(0)	(1)	173,797
5630000	Overhead Line Expenses	28,431	2	0	28,429
5640000	Underground Line Expenses	16	0	0	16
5650002	Transmssn Elec by Others-NAC	71,535	0	71,535	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	61,479,638	0	0
5650012	PJM Trans Enhancement Charge	1,549,911	0	1,549,911	0
5650015	PJM TO Serv Exp - Aff	125,456	0	125,456	0
5650016	PJM NITS Expense - Affiliated	55,884,740	0	55,884,740	0
5650019	Affil PJM Trans Enhncement Exp	4,124,242	0	4,124,242	0
5650020	PROVISION RTO Affl Expense	(3,360,708)	0	(3,360,708)	0
5650021	PJM NITS Expense - Non-Affilia	650,253	0	650,253	0
5650023	Amort of PROVISION RTO Expense	41,108	0	41,108	0
5660000	Misc Transmission Expenses	970,418	118,437	2,591	849,389
5660009	PJM OATT LSE Over-Under Adjust	1,248,885	0	1,248,885	0
5660011	Misc Transm Exp - Affiliate	2,617	0	0	2,617
5670002	Rents - Associated	0	0	0	190,807
	Transmission Op Exp	**64,950,667**	**61,648,302**	**61,753,737**	**3,219,074**
5800000	Oper Supervision & Engineering	865,994	862,714	337	2,983
5810000	Load Dispatching	960	960	0	0
5820000	Station Expenses	288,418	284,708	(5)	3,716
5830000	Overhead Line Expenses	250,573	250,796	(1)	37
5840000	Underground Line Expenses	255,834	256,176	0	(341)
5850000	Street Lighting & Signal Sys E	25,168	25,170	0	0
5860000	Meter Expenses	1,106,551	1,107,681	(1)	(65)
5870000	Customer Installations Exp	151,017	151,135	0	(59)
5880000	Miscellaneous Distribution Exp	5,117,931	5,109,640	973	7,815
5890001	Rents - Nonassociated	681,079	681,079	0	0
5890002	Rents - Associated	58,902	58,902	0	0
	Distribution Op Exp	**8,802,426**	**8,788,961**	**1,302**	**14,085**
9010000	Supervision - Customer Accts	7,781	7,741	10	31
9020000	Meter Reading Expenses	28,979	28,979	0	0
9020002	Meter Reading - Regular	227,015	227,102	0	0
9020003	Meter Reading - Large Power	21,380	21,381	0	0
9030000	Cust Records & Collection Exp	235,384	232,699	2	2,682
9030001	Customer Orders & Inquiries	2,196,835	2,196,368	137	367
9030002	Manual Billing	7,774	7,744	16	15
9030003	Postage - Customer Bills	462,422	462,422	0	0
9030004	Cashiering	39,796	39,796	0	0
9030005	Collection Agents Fees & Exp	2,179	2,179	0	0
9030006	Credit & Oth Collection Activi	498,321	498,702	0	0

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	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024
9030007	Collectors	241,184	241,184	0	0
9030009	Data Processing	27,073	27,064	5	5
9040007	Uncoll Accts - Misc Receivable	9,600	9,497	86	18
9050000	Misc Customer Accounts Exp	15,089	15,089	0	0
9070000	Supervision - Customer Service	44,592	44,609	(2)	(11)
9080000	Customer Assistance Expenses	967,911	967,944	0	0
9080009	Cust Assistance Expense - DSM	381,017	381,020	0	0
9100000	Misc Cust Svc&Informational Ex	4,490	2,109	1,227	1,154
	Customer Service and Information Op Exp	**5,418,823**	**5,413,629**	**1,481**	**4,261**
9120000	Demonstrating & Selling Exp	7,196	7,183	4	9
9120003	Demo & Selling Exp - Area Dev	36	36	0	0
9130001	Advertising Exp - Residential	80	72	7	1
	Sales Expenses	**7,311**	**7,291**	**11**	**10**
	Memo: Insurance (9240 9250)	**2,386,087**	**1,276,257**	**893,128**	**216,702**
9200000	Administrative & Gen Salaries	9,598,037	4,558,758	3,527,143	1,512,146
9210001	Off Supl & Exp - Nonassociated	537,207	322,748	155,898	58,604
9210003	Office Supplies & Exp - Trnsf	161	71	62	28
9210020	EMP RECOG - Over 100 Dollars	2	2	1	0
9210021	EMP TRAVEL - Airfare	84	41	34	10
9210022	MEALS & ENT-100 Pct DEDUCTIBLE	100	41	47	12
9210023	EMP TRAVEL-MILEAGE	577	303	180	94
9210024	EMP TRAVEL-PARKING	13	7	5	1
9210025	MEALS & ENT-50 Pct DEDUCTIBLE	43	26	15	2
9210026	EMP TRAVEL-CAR RENTAL	26	15	10	2
9210027	EMP TRAVEL-TAXI AND SHUTTLE	9	5	4	1
9210028	EMP TRAVEL-HOTEL & LODGING	609	221	313	75
9210030	EMP TRAVEL-OTHER	122	92	29	1
9210031	SAFETY EQUIPMENT AND SUPPLIES	7	2	4	1
9210032	FUEL	9	6	3	0
9210033	FOOD SERVICE-CATERING	7	3	3	2
9210034	In-House Training & Seminars	106	0	0	106
9210037	OEM/TECHNICAL TRAINING	246	3	1	241
9210040	DUES-BUSINESS/PROFESSIONAL	27	9	13	6
9210041	VEHICLE-LICENSE FEES	12	4	5	3
9220000	Administrative Exp Trnsf - Cr	(176,790)	(176,790)	(0)	(0)
9220001	Admin Exp Trnsf to Cnstrction	(359,333)	(359,333)	0	0
9220002	Admin Exp Trnsf Const-Mngerial	0	(0)	0	0
9220004	Admin Exp Trnsf to ABD	(263)	(263)	0	0
9220005	Overhead Loadings	(517,880)	(345,828)	(146,741)	(25,311)
9230001	Outside Svcs Empl - Nonassoc	2,154,989	460,357	831,655	862,977
9230003	AEPSC Billed to Client Co	(344,951)	(119,180)	(128,856)	(96,916)
9230024	SRV-MAIL/MESSENGER-POSTAGE	1	1	0	0
9230031	SRV-OUTSIDE SERVICES (TECH)	84	28	39	17
9230034	SRV-SOFTWARE LICENSING	14,817	10,872	3,821	124
9230035	Development Project Expense	116	0	0	116
9240000	Property Insurance	881,077	214,029	516,717	150,331
9250000	Injuries and Damages	1,358,977	943,143	351,869	63,964
9250002	Emp Accdent Prvntion-Adm Exp	85	30	28	27
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	280,849	248,842	28,936	3,070
9250007	Prsnal Injries&Prop Dmage-Pub	21,575	0	21,575	0
9250010	Frg Ben Loading - Workers Comp	(156,475)	(129,787)	(25,998)	(691)

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	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024
9260000	Employee Pensions & Benefits	1,937	1,937	0	0
9260001	Edit & Print Empl Pub-Salaries	86	33	37	16
9260002	Pension & Group Ins Admin	21,249	9,757	11,163	329
9260003	Pension Plan	1,604,196	1,075,712	516,108	12,376
9260004	Group Life Insurance Premiums	101,577	64,649	36,371	557
9260005	Group Medical Ins Premiums	3,672,442	2,490,373	1,149,822	32,247
9260007	Group L-T Disability Ins Prem	414,874	248,077	166,440	358
9260009	Group Dental Insurance Prem	128,997	87,780	39,989	1,228
9260010	Training Administration Exp	712	179	259	274
9260012	Employee Activities	9,185	6,854	2,128	203
9260021	Postretirement Benefits - OPEB	69,305	37,743	30,604	958
9260027	Savings Plan Contributions	1,355,223	888,211	457,468	9,544
9260036	Deferred Compensation	8,845	8,845	0	0
9260037	Supplemental Pension	18,639	18,595	44	0
9260050	Frg Ben Loading - Pension	(708,433)	(608,687)	(89,516)	(10,231)
9260051	Frg Ben Loading - Grp Ins	(1,925,229)	(1,654,509)	(245,504)	(25,216)
9260052	Frg Ben Loading - Savings	(589,562)	(501,417)	(79,410)	(8,735)
9260053	Frg Ben Loading - OPEB	(70,551)	(58,407)	(11,032)	(1,112)
9260055	IntercoFringeOffset- Don't Use	(338,711)	(338,711)	0	0
9260058	Frg Ben Loading - Accrual	(149,097)	(119,500)	(27,715)	(1,881)
9260060	Amort-Post Retirerment Benefit	162,465	97,186	53,405	11,874
9270000	Franchise Requirements	122,271	120,928	699	644
9280000	Regulatory Commission Exp	7,214	3,139	2,127	1,949
9280001	Regulatory Commission Exp-Adm	4,350	4,186	159	4
9280002	Regulatory Commission Exp-Case	2,229,202	1,141,068	524,020	564,117
9280005	Reg Com Exp-FERC Trans Cases	17,357	418	453	16,486
9280006	State Publ Serv CommissionFees	712,899	712,899	0	0
9301000	General Advertising Expenses	17,114	7,634	4,932	4,547
9301001	Newspaper Advertising Space	20,255	9,132	5,648	5,475
9301003	TV Station Advertising Time	19,441	8,808	5,522	5,112
9301012	Public Opinion Surveys	12,539	12,538	1	1
9301015	Other Corporate Comm Exp	5,297	5,297	0	0
9302000	Misc General Expenses	221,613	88,534	85,461	47,618
9302003	Corporate & Fiscal Expenses	79,800	45,306	27,341	7,152
9302004	Research, Develop&Demonstr Exp	584	201	286	98
9310001	Rents - Real Property	7,200	7,200	0	0
9310002	Rents - Personal Property	39,723	32,875	6,198	650
	Administration & General	**20,599,293**	**9,583,338**	**7,810,324**	**3,205,688**
4111005	Accretion Expense	851,542	11,525	840,017	0
	Accretion	**851,542**	**11,525**	**840,017**	**-**
4116000	Gain From Disposition of Plant	(10,887)	(10,887)	0	0
	Loss/(Gain) on Utility Plant	**(10,887)**	**(10,887)**	**-**	**-**
9302006	Assoc Bus Dev - Materials Sold	116,255	116,255	0	0
9302007	Assoc Business Development Exp	154,207	125,174	229	28,812
	Associated Business Development Expenses	**270,462**	**241,429**	**229**	**28,812**
	Gain on Disposition of Property	**-**	**-**	**-**	**-**
4212000	Loss on Dspsition of Property	174	0	174	0
	Loss on Disposition of Property	**174**	**-**	**174**	**-**
	Loss(Gain) of Sale of Property	**174**	**-**	**174**	**-**
4265009	Factored Cust A/R Exp - Affil	2,454,691	2,454,691	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	1,504,437	1,504,437	0	0

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	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024
	Opr Exp and Factored A/R	**3,959,128**	**3,959,128**	**-**	**-**
	Water Heaters	**-**	**-**	**-**	**-**
4040007	Cloud Implement - Amort Plant	324,497	228,542	60,381	35,574
4171006	Outside Services - Other	100	100	0	0
4265004	Social & Service Club Dues	30,419	8,323	20,022	2,074
4265007	Regulatory Expenses	3,476	1,558	992	927
	Expense of Non-Utility Operation	**358,492**	**238,523**	**81,394**	**38,575**
4210009	Misc Non-Op Exp - NonAssoc	16,883	16,698	75	110
	Misc NonOp Expenses - NonAssoc	**16,883**	**16,698**	**75**	**110**
4261000	Donations	1,213,616	1,201,378	6,597	5,640
	Donation Contributions	**1,213,616**	**1,201,378**	**6,597**	**5,640**
4263001	Penalties	2,062	842	889	331
	Provision for Penalties	**2,062**	**842**	**889**	**331**
4264000	Civic and Political Activity	154,927	79,578	38,788	36,565
4264001	Non-deduct Lobbying per IRS	14,223	4,883	6,467	2,873
	Civic & Political Activities	**169,151**	**84,461**	**45,255**	**39,437**
4265002	Other Deductions - Nonassoc	341,119	311,810	20,420	8,889
	Other Deductions	**341,119**	**311,810**	**20,420**	**8,889**
	Shutdown Coal Company Expenses	**-**	**-**	**-**	**-**
	All Other Operational Expenses	**6,060,452**	**5,812,840**	**154,631**	**92,982**
	Operational Expenses	**118,563,357**	**91,543,891**	**82,114,241**	**6,578,208**
5100000	Maint Supv & Engineering	1,331,858	0	1,331,858	0
5110000	Maintenance of Structures	1,424,528	0	1,424,528	0
5120000	Maintenance of Boiler Plant	9,952,797	0	9,952,797	0
5120034	BSDR O/U Recovery - Maint Cost	(7,167)	0	(7,167)	0
5120037	KY Steam Maint O/U	(488,134)	0	(488,134)	0
5130000	Maintenance of Electric Plant	2,782,588	0	2,782,588	0
5140000	Maintenance of Misc Steam Plt	1,210,718	0	1,210,718	0
5140025	Maint MiscStmPlt Environmental	(14)	0	(14)	0
	Steam Generation Maintenance	**16,207,174**	**-**	**16,207,174**	**-**
	Nuclear Generation Maintenance	**-**	**-**	**-**	**-**
	Hydro Generation Maintenance	**-**	**-**	**-**	**-**
	Other Generation Maintenance	**-**	**-**	**-**	**-**
5680000	Maint Supv & Engineering	19,699	911	657	18,131
5690000	Maintenance of Structures	32,347	0	0	32,347
5691000	Maint of Computer Hardware	5,388	65	2	5,321
5692000	Maint of Computer Software	161,213	11,143	5,733	144,338
5693000	Maint of Communication Equip	8,562	0	0	8,562
5700000	Maint of Station Equipment	382,559	1,765	1	380,793
5710000	Maintenance of Overhead Lines	4,539,574	(5)	0	4,539,582
5720000	Maint of Underground Lines	579	0	0	579
5730000	Maint of Misc Trnsmssion Plt	2,109	50	5	2,054
	Transmission Maintenance	**5,152,030**	**13,929**	**6,398**	**5,131,706**
5900000	Maint Supv & Engineering	11,655	11,474	0	181
5910000	Maintenance of Structures	9,642	9,632	0	10
5920000	Maint of Station Equipment	793,410	789,024	39	4,347
5930000	Maintenance of Overhead Lines	29,308,601	29,313,848	62	395
5930001	Tree and Brush Control	320,339	320,271	0	0
5940000	Maint of Underground Lines	34,703	34,713	0	(2)
5950000	Maint of Lne Trnf,Rglators&Dvi	14,907	14,906	0	9
5960000	Maint of Strt Lghtng & Sgnal S	7,170	7,171	0	0

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	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024
5970000	Maintenance of Meters	27,123	27,149	0	(0)
5980000	Maint of Misc Distribution Plt	25,529	25,523	1	7
	Distribution Maintenance	**30,553,079**	**30,553,711**	**102**	**4,946**
9350000	Maintenance of General Plant	19,976	15,140	4,836	0
9350001	Maint of Structures - Owned	637,890	630,164	4,956	2,771
9350002	Maint of Structures - Leased	2,515	1,919	330	266
9350012	Maint of Data Equipment	3,404	2,529	875	0
9350013	Maint of Cmmncation Eq-Unall	865,611	834,194	32,061	0
9350015	Maint of Office Furniture & Eq	752,164	360,564	391,600	0
9350023	Site Communications Services	98	72	26	0
9350024	Maint of DA-AMI Comm Equip	4,653	4,399	77	179
	Administration & General Maintenance	**2,286,312**	**1,848,981**	**434,761**	**3,215**
	All Other Maintenance Expenses	**-**	**-**	**-**	**-**
	Maintenance Expenses	**54,198,595**	**32,416,622**	**16,648,436**	**5,139,867**
	Total Operational and Maintenance Expenses	**172,761,952**	**123,960,513**	**98,762,677**	**11,718,076**
4040001	Amort. of Plant	7,012,670	3,492,420	2,409,274	1,110,977
4060001	Amort of Plt Acq Adj	28,962	0	0	28,962
	DDA Amortization	**7,041,632**	**3,492,420**	**2,409,274**	**1,139,939**
4073000	Regulatory Debits	(0)	0	(0)	0
4073014	Regulatory Debit - BSDR	319,049	0	319,049	0
	DDA Regulatory Debits	**319,049**	**-**	**319,049**	**-**
4074000	Regulatory Credits	(2,727,306)	0	(2,727,306)	0
4074025	PPA RIDER Over/Under	2,377,089	0	2,377,089	0
	DDA Regulatory Credits	**(350,218)**	**-**	**(350,218)**	**-**
	Amortization	**7,010,464**	**3,492,420**	**2,378,105**	**1,139,939**
4030001	Depreciation Exp	79,191,916	33,557,632	27,755,988	17,878,297
4030029	Over/Undr Depr Exp Var Riders	(1,225,903)	0	(1,225,903)	0
	DDA Depreciation	**77,966,013**	**33,557,632**	**26,530,084**	**17,878,297**
	DDA STP Nuclear Decommissioning	**-**	**-**	**-**	**-**
4031001	Depr - Asset Retirement Oblig	731,905	7,289	724,616	0
	DDA Asset Retirement Obligation	**731,905**	**7,289**	**724,616**	**-**
	DDA Removal Costs	**-**	**-**	**-**	**-**
	Depreciation	**78,697,918**	**33,564,921**	**27,254,701**	**17,878,297**
	Depreciation and Amortization	**85,708,382**	**37,057,341**	**29,632,806**	**19,018,235**
	Franchise Taxes	**-**	**-**	**-**	**-**
408100624	State Gross Receipts Tax	14,847	3	14,844	0
	Revenue-kWhr Taxes	**14,847**	**3**	**14,844**	**-**
4081002	FICA	2,665,938	1,813,316	836,813	15,808
4081003	Federal Unemployment Tax	13,249	8,283	4,874	92
4081007	State Unemployment Tax	23,044	8,184	14,777	83
4081033	Fringe Benefit Loading - FICA	(1,097,218)	(934,660)	(146,820)	(15,738)
4081034	Fringe Benefit Loading - FUT	(5,330)	(4,537)	(697)	(96)
4081035	Fringe Benefit Loading - SUT	(5,799)	(3,563)	(2,070)	(166)
	Payroll Taxes	**1,593,884**	**887,024**	**706,877**	**(17)**
408102022	State Business Occup Taxes	(28,789)	0	(28,789)	0
408102023	State Business Occup Taxes	8,974	0	8,974	0
408102024	State Business Occup Taxes	5,527,408	0	5,527,408	0
	Capacity Taxes	**5,507,593**	**-**	**5,507,593**	**-**
408100521	Real Personal Property Taxes	832,990	778,009	7	54,974

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17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024
408100522	Real Personal Property Taxes	1,560,190	(10)	1,560,200	0
408100523	Real Personal Property Taxes	16,435,141	8,639,881	2,401,577	5,393,682
408102922	Real-Pers Prop Tax-Cap Leases	(372,463)	(187,830)	(5,727)	(178,907)
408102923	Real-Pers Prop Tax-Cap Leases	(832)	0	(832)	0
408102924	Real-Pers Prop Tax-Cap Leases	463,228	434,421	17,989	10,818
408103623	Real Prop Tax-Cap Leases	7,431	7,431	0	0
408103624	Real Prop Tax-Cap Leases	10,206	10,206	0	0
408200523	Real Personal Property Taxes	42,106	80	41,261	765
408200524	Real Personal Property Taxes	16,626	0	16,626	0
	Property Taxes	**18,994,623**	**9,682,189**	**4,031,101**	**5,281,333**
	Regulatory Fees	**-**	**-**	**-**	**-**
408101423	Federal Excise Taxes	725	0	725	0
408101424	Federal Excise Taxes	2,110	0	2,110	0
	Production Taxes	**2,836**	**-**	**2,836**	**-**
408101923	State Sales and Use Taxes	1,530	1,530	0	0
408101924	State Sales and Use Taxes	39,120	9,412	29,708	0
	Miscellaneous Taxes	**40,651**	**10,943**	**29,708**	**-**
	Other Non-Income Taxes	**43,486**	**10,943**	**32,544**	**-**
	Taxes Other Than Income Taxes	**26,154,433**	**10,580,159**	**10,292,958**	**5,281,316**
	TOTAL OPERATING EXPENSES	**284,624,767**	**171,598,012**	**138,688,441**	**36,017,627**
	Memo: SEC Total Operating Expenses	**462,113,544**	**485,282,261**	**316,175,888**	**36,018,954**
	OPERATING INCOME	**60,697,087**	**(378,714)**	**(37,674,098)**	**98,741,030**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	129,393	5,668	123,726	0
	Interest & Dividend NonAffiliated	**129,393**	**5,668**	**123,726**	**-**
4190005	Interest Income - Assoc CBP	309	309	0	0
	Interest & Dividend Affiliated	**309**	**309**	**-**	**-**
	Total Interest & Dividend Income	**129,702**	**5,976**	**123,726**	**-**
	Interest & Dividend Carrying Charge	**-**	**-**	**-**	**-**
	Memo: Total Interest & Dividend Income w/ Carrying	**129,702**	**5,976**	**123,726**	**-**
9260042	SERP Pension - Non-Service	(2,898)	(2,883)	(15)	0
9260043	OPEB - Non-Service	2,083,494	823,184	1,196,998	63,313
9260062	Pension Plan - Non-Service	3,077,706	810,464	2,320,348	(53,105)
	Other Components of Net Periodic Pension	**5,158,303**	**1,630,765**	**3,517,331**	**10,208**
4191000	Allw Oth Fnds Usd Drng Cnstr	1,820,442	450,792	385,829	983,821
	AFUDC	**1,820,442**	**450,792**	**385,829**	**983,821**
	Gain on Disposition of Equity Investments	**-**	**-**	**-**	**-**
	Interest LTD FMB	**-**	**-**	**-**	**-**
4270002	Int on LTD - Install Pur Contr	(2,291,250)	(2,291,250)	0	0
	Interest LTD IPC	**(2,291,250)**	**(2,291,250)**	**-**	**-**
4300001	Interest Exp - Assoc Non-CBP	(841,257)	(841,257)	0	0
	Interest LTD Notes Payable - Affiliated	**(841,257)**	**(841,257)**	**-**	**-**
	Interest LTD Notes Payable - NonAffiliated	**-**	**-**	**-**	**-**
	Interest LTD Debentures	**-**	**-**	**-**	**-**
4270006	Int on LTD - Sen Unsec Notes	(43,069,186)	(43,069,186)	0	0
	Interest LTD Senior Unsecured	**(43,069,186)**	**(43,069,186)**	**-**	**-**
	Interest LTD Other - Affil	**-**	**-**	**-**	**-**

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American Electric Power

IS8016 YTD Sep 2024 10/18/2024 15:50	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024
4270005	Int on LTD - Other LTD	(7,262,385)	(7,262,385)	0	0
	Interest LTD Other - NonAffil	**(7,262,385)**	**(7,262,385)**	**-**	**-**
	Interest on Long-Term Debt	**(53,464,078)**	**(53,464,078)**	**-**	**-**
4300003	Int to Assoc Co - CBP	(3,056,383)	31,348,267	(44,212,720)	9,808,071
	Interest STD - Affil	**(3,056,383)**	**31,348,267**	**(44,212,720)**	**9,808,071**
4310007	Lines Of Credit	(512,818)	(226,903)	(187,523)	(98,391)
	Interest STD - NonAffil	**(512,818)**	**(226,903)**	**(187,523)**	**(98,391)**
	Interest on Short Term Debt	**(3,569,200)**	**31,121,364**	**(44,400,244)**	**9,709,680**
4280002	Amrtz Debt Dscnt&Exp-Instl Pur	(128,715)	(128,715)	0	0
4280003	Amrtz Debt Dscnt&Exp-N/P	(9,003)	(9,003)	0	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	(447,605)	(447,605)	0	0
	Amort of Debt Disc. Prem & Exp	**(585,323)**	**(585,323)**	**-**	**-**
4281004	Amrtz Loss Rcquired Debt-Dbnt	(25,238)	(25,238)	0	0
	Amort Loss on Reacquired Debt	**(25,238)**	**(25,238)**	**-**	**-**
	Amort Gain on Reacquired Debt	**-**	**-**	**-**	**-**
	Other Interest - Fuel Recovery	**-**	**-**	**-**	**-**
4310001	Other Interest Expense	8,411,889	17,951	8,383,520	10,418
4310002	Interest on Customer Deposits	(1,516,661)	(1,516,661)	0	0
9310005	Int on Regulated Fin Leases	(8,869)	0	0	0
	Other Interest - NonAffil	**6,886,359**	**(1,498,710)**	**8,383,520**	**10,418**
	Other Interest Expense - Affil	**-**	**-**	**-**	**-**
	Interest Rate Hedge Unrealized (Gain)/Loss	**-**	**-**	**-**	**-**
4320000	Allw Brrwed Fnds Used Cnstr-Cr	2,749,664	700,368	578,608	1,470,688
	AFUDC-Borrowed Funds	**2,749,664**	**700,368**	**578,608**	**1,470,688**
	Total Interest Charges	**(48,007,817)**	**(23,751,617)**	**(35,438,115)**	**11,190,785**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**19,797,717**	**(22,042,798)**	**(69,085,328)**	**110,925,844**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	2,097,381	(6,636,779)	(10,370,242)	19,104,402
4092001	Inc Tax, Oth Inc&Ded-Federal	(309,571)	(253,984)	(54,753)	(835)
	Federal Current Income Tax	**1,787,810**	**(6,890,763)**	**(10,424,994)**	**19,103,567**
4101001	Prov Def I/T Util Op Inc-Fed	39,966,203	8,414,629	27,490,247	4,061,326
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(39,498,505)	(4,968,412)	(32,176,648)	(2,353,445)
	Federal Deferred Income Tax	**467,698**	**3,446,217**	**(4,686,401)**	**1,707,881**
	Federal Investment Tax Credits	**-**	**-**	**-**	**-**
	Federal Income Taxes	**2,255,508**	**(3,444,546)**	**(15,111,395)**	**20,811,449**
4091002	Income Taxes, UOI - State	209,596	(177,234)	(166,728)	553,558
409100223	Income Taxes UOI - State	(255,377)	(1,814,309)	(2,126,994)	3,685,926
4092002	Inc Tax, Oth Inc & Ded - State	(7,768)	(6,089)	(1,700)	21
409200223	Inc Tax Oth Inc Ded - State	(69,925)	(57,653)	(12,042)	(231)
	State Current Income Tax	**(123,474)**	**(2,055,286)**	**(2,307,462)**	**4,239,274**
4111002	Prv Def I/T-Cr UtilOpInc-State	(301,808)	0	(301,808)	0
	State Deferred Income Tax	**(301,808)**	**-**	**(301,808)**	**-**
	State Investment Tax Credits	**-**	**-**	**-**	**-**
	State Income Taxes	**(425,282)**	**(2,055,286)**	**(2,609,270)**	**4,239,274**
	Local Current Income Tax	**-**	**-**	**-**	**-**
	Local Deferred Income Tax	**-**	**-**	**-**	**-**
	Local Investment Tax Credits	**-**	**-**	**-**	**-**
	Local Income Taxes	**-**	**-**	**-**	**-**
	Foreign Current Income Tax	**-**	**-**	**-**	**-**

American Electric Power

IS8016 YTD Sep 2024 10/18/2024 15:50	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024
	Foreign Deferred Income Tax	-	-	-	-
	Foreign Investment Tax Credits	-	-	-	-
	Foreign Income Taxes	-	-	-	-
	Total Income Taxes	1,830,226	(5,499,832)	(17,720,666)	25,050,723
	Equity Earnings of Subs	-	-	-	-
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	17,967,491	(16,542,967)	(51,364,663)	85,875,121
	Discontinued Operations (Net of Taxes)	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-
	NET INCOME	17,967,491	(16,542,967)	(51,364,663)	85,875,121
	Minority Interest	-	-	-	-
	Preferred Stock Dividend Subs	-	-	-	-
	Earnings to Common Shareholders	17,967,491	(16,542,967)	(51,364,663)	85,875,121
	NET INCOME (LOSS) NODE before PS	17,967,491	(16,542,967)	(51,364,663)	85,875,121

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BS8216 YTD Sep 2024 10/18/2024 15:13	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024
	ASSETS				
	Cash and Cash Equivalents	**1,333,859**	**1,333,859**	**0**	**0**
	Other Cash Deposits	**39,370**	**17,496**	**21,256**	**618**
	Customers	13,806,302	10,613,705	593,806	2,598,790
	Accrued Unbilled Revenues	2,630,426	2,630,426	0	0
	Miscellaneous Accounts Receivable	16,073,404	4,530,029	50,912,250	16,243,134
	Allowances for Uncollectible Accounts	(348)	(247)	(85)	(16)
	Accounts Receivable	**32,509,785**	**17,773,913**	**51,505,972**	**18,841,908**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**91,904,382**	**6,524,203**	**81,857,834**	**3,522,345**
	Risk Management Contracts - Current	**7,051,745**	**0**	**7,051,745**	**0**
	Margin Deposits	**5,896,072**	**54,140**	**5,841,932**	**0**
	Unrecovered Fuel - Current	**8,262,255**	**0**	**8,262,255**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**3,897,727**	**3,087,219**	**571,622**	**238,885**
	TOTAL CURRENT ASSETS	**150,895,195**	**28,790,831**	**155,112,616**	**22,603,757**
	Electric Production	**1,282,145,313**	**1,294,049,593**	**1,317,561,514**	**874,394,564**
	Electric Transmission	**869,940,919**	**0**	**0**	**0**
	Electric Distribution	**1,160,908,388**	**0**	**0**	**0**
	General Property, Plant and Equipment	**174,168,585**	**83,276**	**(45,138)**	**1,119,396**
	Construction Work-in-Progress	**187,601,588**	**65,444,068**	**7,411,178**	**114,746,342**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,674,764,793**	**1,359,576,937**	**1,324,927,555**	**990,260,301**
	less: Accumulated Depreciation and Amortization	**(1,244,753,089)**	**(330,475,777)**	**(647,563,627)**	**(266,713,685)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,430,011,703**	**1,029,101,159**	**677,363,928**	**723,546,616**
	Net Regulatory Assets	**605,887,757**	**135,899,457**	**460,248,458**	**9,739,842**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Assets	**26,462,223**	**13,812,399**	**11,876,437**	**773,387**
	Other Non Current Assets	**31,373,640**	**8,007,989**	**20,605,460**	**2,760,191**
	TOTAL OTHER NON-CURRENT ASSETS	**663,723,621**	**157,719,846**	**492,730,355**	**13,273,420**
	Assets Held for Sale				
	Assets of Discontinued Operations				
	TOTAL ASSETS	**3,244,630,520**	**1,215,611,836**	**1,325,206,900**	**759,423,793**
	LIABILITIES				
	Accounts Payable	**109,828,479**	**91,518,230**	**53,461,234**	**20,461,024**
	Advances from Affiliates	**148,530,435**	**(645,820,273)**	**1,059,033,290**	**(264,682,582)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**150,000,000**	**150,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	2,625,213	66,412	2,558,801	0
2440021	S/T Liability MTM Collateral	(134,443)	(66,412)	(68,031)	0

BS8216 YTD Sep 2024 10/18/2024 15:13	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024
	Risk Management Liabilities - MTM	2,490,770	0	2,490,770	0
	Risk Management Liabilities	**2,490,770**	**0**	**2,490,770**	**0**
	Accrued Taxes	**23,944,948**	(2,712,181)	(37,521,238)	**64,178,366**
	Memo: Property Taxes	33,355,488	18,485,348	4,538,507	10,331,634
	Accrued Interest	**19,071,917**	**19,071,917**	**0**	**0**
	Risk Management Collateral	496,705	0	496,705	0
	Utility Customer Deposits	37,495,887	37,495,887	0	0
	Deposits - Customer and Collateral	**37,992,592**	**37,495,887**	**496,705**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	129,335	49,969	79,365	0
	Obligations under Operating Leases - Current	230,544	97,101	62,479	70,965
	Tax Collections Payable	2,410,167	2,410,167	0	0
	Revenue Refunds - Accrued	437,010	0	136,187	300,823
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	1,533,406	1,414,581	108,414	10,411
	Accrued Rents	0	0	0	0
	Accrued ICP	1,536,564	1,417,563	112,923	6,079
	Accrued Vacations	2,346,348	2,095,836	229,990	20,523
	Misc Employee Benefits	1,190,515	1,001,933	186,762	1,820
	Payroll Deductions	95,022	84,124	9,635	1,264
	Severance / SEI	728	728	0	0
	Accrued Workers Compensation	191,535	191,055	480	0
2530022	Customer Advance Receipts	2,457,676	2,457,676	0	0
	Customer Advance	2,457,676	2,457,676	0	0
2420511	Control Cash Disburse Account	6,035,784	6,035,784	0	0
	Control Cash Disbursement Account	6,035,784	6,035,784	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	118,665	0	118,665	0
2300002	ARO - Current	1,442,506	0	1,442,506	0
2420088	Econ. Development Fund Curr	438,257	438,257	0	0
2420512	Unclaimed Funds	21,503	21,503	0	0
2420542	Acc Cash Franchise Req	73,489	73,489	0	0
2420643	Accrued Audit Fees	80,718	33,987	30,443	16,288
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	357,219	356,397	0	823
2530112	Other Deferred Credits-Curr	1,756	1,756	0	0
2530124	Contr In Aid of Constr Advance	266,785	266,785	0	0
	Misc Current and Accrued Liabilities	2,801,582	1,192,858	1,591,613	17,110
	Current Other and Accrued Liabilities	21,036,338	18,302,305	2,376,003	358,030
	Other Current Liabilities	**21,396,217**	**18,449,375**	**2,517,847**	**428,995**
	TOTAL CURRENT LIABILITIES	**513,255,358**	(331,997,045)	**1,080,478,608**	(179,614,196)
	Long-Term Debt - Affiliated	**0**	**0**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,060,924,607**	**1,060,924,607**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	(609,719)	(609,719)	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,060,314,888*	*1,060,314,888*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	655,888	11,332	644,556	0

BS8216 YTD Sep 2024 10/18/2024 15:13	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024	YTD Sep 2024
2440022	L/T Liability MTM Collateral	(11,332)	(11,332)	0	0
	Long-Term Risk Management Liabilities - MTM	644,556	0	644,556	0
	Long-Term Risk Management Liabilities	**644,556**	**0**	**644,556**	**0**
	Deferred Income Taxes	**482,070,176**	**168,956,782**	**218,970,544**	**94,142,850**
	Deferred Investment Tax Credits	**0**	**0**	**0**	**0**
	Regulatory Liabilities and Deferred Credits	**114,347,321**	**84,626,510**	**(3,267,123)**	**32,987,934**
	Memo - Reg Liab and Def ITC	*114,347,321*	*84,626,510*	*(3,267,123)*	*32,987,934*
	Asset Retirement Obligation	**86,369,681**	**212,589**	**86,157,092**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**7,391,518**	**11,155,839**	**(5,535,371)**	**1,771,050**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redemption	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	731,805	558,483	173,321	0
	Obligations Under Operating Leases	1,759,809	1,272,831	189,616	297,361
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	99,203	99,203	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	29,520	29,520	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	296	0	0	296
2530175	Legal Contingencies	(165)	(165)	0	0
2530185	O\U Accounting of ExpensesT	3,327	0	3,327	0
2530188	Long Term Assoc AP	3,666,507	0	0	3,666,507
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	3,784,100	29,355	3,327	3,751,418
	Total Other Deferred Credits	3,883,303	128,558	3,327	3,751,418
	Accumulated Provisions - Rate Refund	666,787	0	0	666,787
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**7,041,704**	**1,959,872**	**366,264**	**4,715,567**
	TOTAL NON-CURRENT LIABILITIES	**1,758,179,844**	**1,327,226,481**	**297,335,963**	**133,617,400**
	TOTAL LIABILITIES	**2,271,435,202**	**995,229,436**	**1,377,814,571**	**(45,996,796)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**527,243,589**	**106,025,371**	**336,531,464**	**84,686,754**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**395,501,729**	**91,952,979**	**(399,426,738)**	**702,975,488**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**973,195,318**	**220,382,399**	**(52,607,671)**	**805,420,589**
	Memo: Total Equity	973,195,318	220,382,399	(52,607,671)	805,420,589
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,244,630,520**	**1,215,611,836**	**1,325,206,900**	**759,423,793**

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BS8216 YTD Sep 2023 11/02/2023 13:37	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Sep 2023	YTD Sep 2023	YTD Sep 2023	YTD Sep 2023
	ASSETS				
	Cash and Cash Equivalents	**1,277,446**	**1,277,446**	**0**	**0**
	Other Cash Deposits	**55,764**	**22,325**	**32,470**	**969**
	Customers	11,557,375	10,821,105	(225,623)	961,894
	Accrued Unbilled Revenues	4,219,170	4,219,170	0	0
	Miscellaneous Accounts Receivable	13,386,880	3,940,898	43,893,375	18,019,487
	Allowances for Uncollectible Accounts	(1,019)	(318)	0	(701)
	Accounts Receivable	**29,162,405**	**18,980,854**	**43,667,752**	**18,980,679**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**94,582,784**	**8,037,892**	**83,991,832**	**2,553,060**
	Risk Management Contracts - Current	**6,931,820**	**0**	**6,931,820**	**0**
	Margin Deposits	**709,763**	**0**	**709,763**	**0**
	Unrecovered Fuel - Current	**6,291,182**	**0**	**6,291,182**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**3,209,827**	**2,454,867**	**535,289**	**219,671**
	TOTAL CURRENT ASSETS	**142,220,991**	**30,773,384**	**142,160,107**	**21,754,380**
	Electric Production	**1,240,900,301**	**1,227,655,501**	**1,278,994,673**	**823,444,726**
	Electric Transmission	**819,865,700**	**0**	**0**	**0**
	Electric Distribution	**1,097,736,505**	**0**	**0**	**0**
	General Property, Plant and Equipment	**172,819,275**	**83,276**	**24,208**	**1,119,396**
	Construction Work-in-Progress	**167,292,007**	**64,434,462**	**22,031,368**	**80,826,177**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,498,613,788**	**1,292,173,240**	**1,301,050,249**	**905,390,299**
	less: Accumulated Depreciation and Amortization	(1,192,803,541)	(316,099,545)	(623,520,581)	(253,183,415)
	NET PROPERTY, PLANT and EQUIPMENT	**2,305,810,247**	**976,073,695**	**677,529,668**	**652,206,884**
	Net Regulatory Assets	**526,310,797**	**126,521,868**	**392,996,393**	**6,792,536**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Consol Subs	0	0	0	0
	Investments in Non-Consol Subs	0	0	0	0
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Assets	**21,927,489**	**11,498,511**	**9,890,190**	**538,787**
	Other Non Current Assets	**21,072,070**	**5,821,561**	**13,634,811**	**1,615,698**
	TOTAL OTHER NON-CURRENT ASSETS	**569,310,356**	**143,841,940**	**416,521,394**	**8,947,022**
	Assets Held for Sale				
	Assets of Discontinued Operations				
	TOTAL ASSETS	**3,017,341,594**	**1,150,689,020**	**1,236,211,169**	**682,908,285**
	LIABILITIES				
	Accounts Payable	**86,121,519**	**75,287,287**	**55,190,698**	**8,110,413**
	Advances from Affiliates	**100,885,973**	**(674,452,461)**	**951,899,678**	**(176,561,244)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**490,000,000**	**490,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	1,620,009	0	1,620,009	0
	Risk Management Liabilities - MTM	1,620,009	0	1,620,009	0

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BS8216 YTD Sep 2023 11/02/2023 13:37	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Sep 2023	YTD Sep 2023	YTD Sep 2023	YTD Sep 2023
	Risk Management Liabilities	**1,620,009**	**0**	**1,620,009**	**0**
	Accrued Taxes	**20,767,907**	**6,828,349**	**(14,139,947)**	**28,079,506**
	Memo: Property Taxes	21,860,152	11,065,787	3,467,060	7,327,305
	Accrued Interest	**11,748,634**	**11,748,634**	**0**	**0**
	Risk Management Collateral	465,543	0	465,543	0
	Utility Customer Deposits	40,421,485	40,421,485	0	0
	Deposits - Customer and Collateral	**40,887,028**	**40,421,485**	**465,543**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	113,433	37,051	76,382	0
	Obligations under Operating Leases - Current	139,726	95,088	41,610	3,028
	Tax Collections Payable	2,225,144	2,225,144	0	0
	Revenue Refunds - Accrued	107,020	0	107,020	(0)
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	1,023,947	912,812	102,207	8,929
	Accrued Rents	0	0	0	0
	Accrued ICP	1,615,925	1,496,394	113,540	5,991
	Accrued Vacations	2,682,881	2,370,653	291,026	21,202
	Misc Employee Benefits	1,636,720	858,241	776,544	1,935
	Payroll Deductions	119,735	94,350	24,114	1,272
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	199,921	181,854	18,067	0
2530022	Customer Advance Receipts	4,818,421	4,818,421	0	0
	Customer Advance	4,818,421	4,818,421	0	0
2420511	Control Cash Disburse Account	3,299,276	3,299,276	0	0
	Control Cash Disbursement Account	3,299,276	3,299,276	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	111,171	0	111,171	0
2300002	ARO - Current	29,797	0	29,797	0
2420088	Econ. Development Fund Curr	395,533	395,533	0	0
2420512	Unclaimed Funds	7,541	7,541	0	0
2420542	Acc Cash Franchise Req	65,088	65,088	0	0
2420643	Accrued Audit Fees	5,045	1,799	2,145	1,100
2420656	Federal Mitigation Accru (NSR)	244,045	0	244,045	0
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	378,306	377,399	0	907
2530112	Other Deferred Credits-Curr	189,863	188,496	0	1,367
2530124	Contr In Aid of Constr Advance	200,526	200,526	0	0
2530177	Deferred Rev-Bonus Lease Curr	11,384	0	11,384	0
	Misc Current and Accrued Liabilities	1,638,982	1,237,066	398,542	3,374
	Current Other and Accrued Liabilities	19,367,972	17,494,209	1,831,060	42,704
	Other Current Liabilities	**19,621,132**	**17,626,348**	**1,949,052**	**45,731**
	TOTAL CURRENT LIABILITIES	**771,652,201**	**(32,540,358)**	**996,985,033**	**(140,325,595)**
	Long-Term Debt - Affiliated	**25,000,000**	**25,000,000**	**0**	**0**
	Long-Term Debt - Non Affiliated	**688,315,318**	**688,315,318**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**0**	**0**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*688,315,318*	*688,315,318*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	509,672	0	509,672	0
	Long-Term Risk Management Liabilities - MTM	509,672	0	509,672	0

BS8216 YTD Sep 2023 11/02/2023 13:37	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Sep 2023	YTD Sep 2023	YTD Sep 2023	YTD Sep 2023
	Long-Term Risk Management Liabilities	**509,672**	**0**	**509,672**	**0**
	Deferred Income Taxes	**465,220,252**	**156,361,794**	**217,596,824**	**91,261,634**
	Deferred Investment Tax Credits	**(0)**	**0**	**(0)**	**0**
	Regulatory Liabilities and Deferred Credits	**94,916,403**	**65,421,360**	**1,821,027**	**27,674,016**
	Memo - Reg Liab and Def ITC	*94,916,403*	*65,421,360*	*1,821,027*	*27,674,016*
	Asset Retirement Obligation	**18,419,660**	**197,674**	**18,221,986**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**7,960,505**	**10,982,548**	**(4,591,692)**	**1,569,649**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redem	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	564,567	333,463	231,104	0
	Obligations Under Operating Leases	561,187	322,627	238,561	0
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	112,182	112,182	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	43,599	43,599	0	0
2530101	MACSS Unidentified EDI Cash	1,375	1,375	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	1,184	0	0	1,184
2530175	Legal Contingencies	(1,274)	(1,274)	0	0
2530185	O\U Accounting of ExpensesT	3,009	0	3,009	0
2530188	Long Term Assoc AP	1,101,727	0	305,637	796,090
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	1,234,235	43,700	308,646	881,890
	Total Other Deferred Credits	1,346,418	155,882	308,646	881,890
	Accumulated Provisions - Rate Refund	1,906,706	0	37,950	1,868,756
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**4,378,878**	**811,971**	**816,261**	**2,750,646**
	TOTAL NON-CURRENT LIABILITIES	**1,304,720,688**	**947,090,665**	**234,374,077**	**123,255,945**
	TOTAL LIABILITIES	**2,076,372,889**	**914,550,307**	**1,231,359,110**	**(17,069,649)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,301,579**	**106,025,371**	**336,070,072**	**84,206,136**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**364,217,126**	**107,709,292**	**(341,505,616)**	**598,013,450**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**940,968,705**	**236,138,713**	**4,852,059**	**699,977,934**
	Memo: Total Equity	940,968,705	236,138,713	4,852,059	699,977,934
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,017,341,594**	**1,150,689,020**	**1,236,211,169**	**682,908,285**

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KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - September, 2024

Final

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		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,276,923,610.03	51,695,418.36	(11,656,261.92)	0.00	0.00	1,316,962,766.47
101/106	CLOUD GENERATION	381,874.02	47,030.54	0.00	0.00	0.00	428,904.56
	TOTAL PRODUCTION	**1,277,305,484.05**	**51,742,448.90**	**(11,656,261.92)**	**0.00**	**0.00**	**1,317,391,671.03**
101/106	TRANSMISSION	842,600,699.05	34,474,090.61	(2,680,225.89)	0.00	0.00	874,394,563.77
101/106	CLOUD TRANSMISSION	201,394.70	75,671.10	0.00	0.00	0.00	277,065.80
101/106	DISTRIBUTION	1,249,889,192.92	52,887,538.92	(10,175,843.61)	0.00	0.00	1,292,600,888.23
101/106	CLOUD DISTRIBUTION	1,618,196.01	329,875.23	0.00	0.00	0.00	1,948,071.24
	TOTAL (ACCOUNTS 101 & 106)	**3,371,614,966.73**	**139,509,624.76**	**(24,512,331.42)**	**0.00**	**0.00**	**3,486,612,260.07**
1011001/12	CAPITAL LEASES	1,080,445.85	0.00	0.00	165,335.20	0.00	1,245,781.05
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**3,372,695,412.58**	**139,509,624.76**	**(24,512,331.42)**	**165,335.20**	**0.00**	**3,487,858,041.12**
1050001	PLANT HELD FOR FUTURE USE	801,671.21	0.00	0.00	0.00	0.00	801,671.21
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEGINNING BALANCE	159,612,262.17					
107000X	ADDITIONS		144,317,701.68				
107000X	TRANSFERS		(116,328,375.69)				
107000X	ENDING BALANCE		27,989,325.99				187,601,588.16
107000X	**CLOUD CONSTRUCTION WIP:**						
107000X	BEGINNING BALANCE	1,540,647.27					
107000X	ADDITIONS		705,453.00				
107000X	TRANSFERS		(452,576.87)				
107000X	ENDING BALANCE		252,876.13				1,793,523.40
	TOTAL ELECTRIC UTILITY PLANT	**3,534,649,993.23**	**167,751,826.88**	**(24,512,331.42)**	**165,335.20**	**0.00**	**3,678,054,823.89**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	571,711.48	0.00	(69,345.76)	0.00	0.00	502,365.72
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1210003	NONUTILITY PROPERTY-WIP						
	BEGINNING BALANCE	0.00					
	ADDITIONS		0.00				
	TRANSFERS		0.00				
	ENDING BALANCE		0.00				0.00
1210016	NONUTILITY PROPERTY-CCNC	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	655,168.37	0.00	0.00	0.00	0.00	655,168.37
	TOTAL NONUTILITY PLANT	**1,226,879.85**	**0.00**	**(69,345.76)**	**0.00**	**0.00**	**1,157,534.09**

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KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - September, 2024

Final

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		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
.	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	623,339,018.27	28,498,973.12	(9,264,225.70)	(4,233,709.94)	(4,118,311.49)	634,221,744.26
1080001/11	TRANSMISSION	284,929,166.47	17,878,296.63	(1,961,177.43)	(790,618.35)	0.00	300,055,667.32
1080001/11	DISTRIBUTION	376,851,080.91	33,565,335.07	(7,679,776.90)	(3,309,387.39)	(152,964.97)	399,274,286.72
1080013	PRODUCTION	(4,098,119.71)	0.00	0.00	0.00	4,098,119.71	0.00
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(151,934.59)	0.00	0.00	0.00	151,934.59	0.00
	RETIREMENT WORK IN PROGRESS	(13,358,319.70)	0.00	0.00	(8,151,623.84)	8,333,715.68	(13,176,227.86)
	TOTAL (108X accounts)	**1,267,510,891.66**	**79,942,604.82**	**(18,905,180.03)**	**(16,485,339.52)**	**8,312,493.52**	**1,320,375,470.45**
	NUCLEAR					0.00	
1110001	PRODUCTION	12,296,619.11	2,547,180.74	(2,392,036.22)	0.00	0.00	12,451,763.63
1110007	CLOUD IMPLEMENT COST PRODUCTI	103,001.61	60,380.53	0.00	0.00	0.00	163,382.14
1110001	TRANSMISSION	4,150,582.38	1,170,135.42	(719,048.46)	0.00	0.00	4,601,669.34
1110007	CLOUD IMPLEMENT COST TRANSMIS	36,477.38	35,574.13	0.00	0.00	0.00	72,051.51
1110001	DISTRIBUTION	14,363,824.54	3,578,553.85	(2,496,066.71)	0.00	0.00	15,446,311.68
1110007	CLOUD IMPLEMENT COST DISTRIBUT	417,883.25	228,542.31	0.00	0.00	0.00	646,425.56
	TOTAL (111X accounts)	**31,368,388.27**	**7,620,366.98**	**(5,607,151.39)**	**0.00**	**0.00**	**33,381,603.86**
1011006	CAPITAL LEASES	291,805.66	0.00	0.00	0.00	90,990.83	382,796.49
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**1,299,171,085.59**	**87,562,971.80**	**(24,512,331.42)**	**(16,485,339.52)**	**8,403,484.35**	**1,354,139,870.80**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	172,262.12	5,002.33	(69,345.76)	69,987.88	0.00	177,906.57
1220002	Depr&Amrt of Nonutl Prop-Leasd	0.00	0.00	0.00	0.00	0.00	0.00
1220003	Depr&Amrt of Nonutl Prop-WIP	69,987.88	0.00	0.00	0.00	(69,987.88)	0.00
1220004	Depletion - Owned	0.00	0.00	0.00	0.00	0.00	0.00
1240027	Other Property - RWIP	35,121.36	0.00	0.00	0.00	0.00	35,121.36
1240028	Other Property - Retirement	(46,947.27)	0.00	0.00	0.00	0.00	(46,947.27)
	TOTAL NONUTILITY PLANT	**230,424.09**	**5,002.33**	**(69,345.76)**	**69,987.88**	**(69,987.88)**	**166,080.66**

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U.S. Department of Energy Energy Information Administration Form EIA-826	**Monthly Electric Utility Sales and Revenue Report with State Distributions – 2024**	Form Approval OMB NO.1905-0129 (Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**

Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650.

Utility Name: Kentucky Power Company — **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan___ Feb___ Mar___ Apr___ May___ Jun___ Jul___ Aug___ Sep_X__ Oct___ Nov___ Dec__ , 2024

Contact Person: Sandra Vargo	**Phone number: 614-716-2671**
Email: slvargo@aep.com	**Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	17,960	14,665	13,630	-	46,255
	b. Megwatthours	113,148	109,380	157,040		379,568
	c. Number of consumers	130,809	30,748	953		162,510
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					

Note:

November 27th, 2024

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed October 2024 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:	
1-12	Income Statement
1-3	Details of Operating Revenues
5-10	Operating Expenses – Functional Expenses
12	Detail Statement of Taxes
Balance Sheet:	
13	Balance Sheet – Assets & Other Debits
13-15	Balance Sheet – Liabilities & Other Credits
14-15	Deferred Credits
15	Statement of Retained Earnings
Utility Property:	
16-17	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Digitally signed by Brian J. Frantz
DN: cn=Brian J. Frantz, c=US, o=AEP, ou=Corporate Accounting, email=bjfrantz@aep.com
Reason: I have reviewed this document
Date: 2024.11.27 09:21:16 -05'00'

Brian J Frantz
Director - Corporate Accounting

American Electric Power

INCOME STATEMENT

IS8016
YTD Oct 2024
11/14/2024 07:55

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Oct 2024	Kentucky Power Company - Distribution 110 Actual YTD Oct 2024	Kentucky Power Company - Generation 117 Actual YTD Oct 2024	Kentucky Power Company - Transmission 180 Actual YTD Oct 2024
		REVENUES				
4400001		Residential Sales-W/Space Htg	114,356,400	114,356,400	0	0
4400002		Residential Sales-W/O Space Ht	53,945,747	54,786,026	(840,279)	0
4400005		Residential Fuel Rev	58,431,356	58,431,356	0	0
	A	**Revenue - Residential Sales**	**226,733,504**	**227,573,783**	**(840,279)**	**-**
4420001		Commercial Sales	81,676,109	82,348,372	(672,263)	0
4420006		Sales to Pub Auth - Schools	13,098,060	13,098,060	0	0
4420007		Sales to Pub Auth - Ex Schools	16,190,341	16,190,341	0	0
4420013		Commercial Fuel Rev	45,841,127	45,841,127	0	0
	A	**Revenue - Commercial Sales**	**156,805,637**	**157,477,901**	**(672,263)**	**-**
	B	**Revenue - Industrial Sales - Affiliated**	**-**	**-**	**-**	**-**
4420002		Industrial Sales (Excl Mines)	60,601,120	61,589,150	(988,031)	0
4420004		Ind Sales-NonAffil(Incl Mines)	14,894,599	14,894,599	0	0
4420016		Industrial Fuel Rev	63,387,996	63,387,996	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**138,883,714**	**139,871,745**	**(988,031)**	**-**
		Revenue - Industrial Sales	**138,883,714**	**139,871,745**	**(988,031)**	**-**
	A	**Revenue - Gas Products Sales**	**-**	**-**	**-**	**-**
	A	**Revenue - Gas Transportation & Storage Sales**	**-**	**-**	**-**	**-**
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	**-**	**-**	**-**	**-**
4440000		Public Street/Highway Lighting	1,492,911	1,496,871	(3,960)	0
4440002		Public St & Hwy Light Fuel Rev	270,371	270,371	0	0
	A	**Revenue - Other Retail Sales**	**1,763,282**	**1,767,242**	**(3,960)**	**-**
	B	**Revenue - Other Retail Sales - Affiliated**	**-**	**-**	**-**	**-**
		Revenue - Retail Sales	**524,186,138**	**526,690,670**	**(2,504,532)**	**-**
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	67,691,945
4561033		PJM NITS Revenue - Affiliated	61,440,776	0	0	61,440,776
4561034		PJM TO Adm. Serv Rev - Aff	209,513	0	0	209,513
4561035		PJM Affiliated Trans NITS Cost	(50,643,153)	0	(50,643,153)	0
4561036		PJM Affiliated Trans TO Cost	(137,087)	0	(137,087)	0
4561059		Affil PJM Trans Enhancmnt Rev	1,302,510	0	0	1,302,510
4561060		Affil PJM Trans Enhancmnt Cost	(1,073,606)	0	(1,073,606)	0
4561062		PROVISION RTO Cost - Affi	800,995	0	800,995	0
4561063		PROVISION RTO Rev Affiliated	2,945,774	0	0	2,945,774
	B	**Revenue - Transmission-Affiliated**	**14,845,721**	**-**	**(51,052,851)**	**133,590,517**
4470150		Transm. Rev.-Dedic. Whlsl/Muni	137,126	0	(2,166,407)	2,303,532
4470206		PJM Trans loss credits-OSS	67,938	0	67,938	0
4470209		PJM transm loss charges-OSS	(173,848)	0	(173,848)	0
4561005		PJM Point to Point Trans Svc	1,816,095	0	1,816,095	0
4561006		PJM Trans Owner Admin Rev	73,946	0	0	73,946
4561007		PJM Network Integ Trans Svc	9,228,086	0	0	9,228,086
4561019		Oth Elec Rev Trans Non Affil	43,241	0	0	43,241
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	4,157	0	0	4,157
4561029		PJM NITS Revenue Whsl Cus-NAff	2,063,846	0	0	2,063,846
4561030		PJM TO Serv Rev Whls Cus-NAff	7,737	0	0	7,737
4561045		PJM Non-Aff Gen IPP Rev	7,976	0	0	7,976
4561058		NonAffil PJM Trans Enhncmt Rev	1,431,751	0	0	1,431,751
4561061		NAff PJM RTEP Rev for Whsl-FR	43,752	0	0	43,752
4561064		PROVISION RTO Rev WhslCus-NAf	99,132	0	0	99,132
4561065		PROVISION RTO Rev - NonAff	430,034	0	(1)	430,035
	A	**Revenue - Transmission-NonAffiliated**	**15,280,970**	**-**	**(456,223)**	**15,737,192**
		Revenue - Transmission	**30,126,690**	**-**	**(51,509,074)**	**149,327,709**

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American Electric Power

INCOME STATEMENT

IS8016
YTD Oct 2024
11/14/2024 07:55

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Oct 2024	Kentucky Power Company - Distribution 110 Actual YTD Oct 2024	Kentucky Power Company - Generation 117 Actual YTD Oct 2024	Kentucky Power Company - Transmission 180 Actual YTD Oct 2024
	B	**Revenue - Resale-Affiliated**	-	-	-	-
4470010		Sales for Resale-Bookout Purch	(19)	0	(19)	0
4470027		Whsal/Muni/Pb Ath Fuel Rev	2,067,863	0	2,067,863	0
4470033		Whsal/Muni/Pub Auth Base Rev	1,467,196	0	1,467,196	0
4470082		Financial Electric Realized	(5,749)	0	(5,749)	0
4470089		PJM Energy Sales Margin	243,182	0	243,182	0
4470098		PJM Oper.Reserve Rev-OSS	(37,951)	0	(37,951)	0
4470099		Capacity Cr. Net Sales	(51,133)	0	(51,133)	0
4470100		PJM FTR Revenue-OSS	196,515	0	196,515	0
4470103		PJM Energy Sales Cost	11,351,734	0	11,351,734	0
4470110		PJM TO Admin. Exp.-NonAff.	4	0	4	0
4470115		PJM Meter Corrections-OSS	41,852	0	41,852	0
4470116		PJM Meter Corrections-LSE	263,174	0	263,174	0
4470126		PJM Incremental Imp Cong-OSS	(298,896)	0	(298,896)	0
4470175		OSS Sharing Reclass - Retail	3,947,601	0	3,947,601	0
4470176		OSS Sharing Reclass-Reduction	(3,947,601)	0	(3,947,601)	0
4470215		PJM 30m Suppl Reserve CH OSS	2,731	0	2,731	0
4470220		PJM Regulation - OSS	3,958,711	0	3,958,711	0
4470221		PJM Spinning Reserve - OSS	51,072	0	51,072	0
5550080		PJM Hourly Net Purch.-FERC	(6,720,216)	0	(6,720,216)	0
	A	**Revenue - Resale-NonAffiliated**	**12,530,070**	**-**	**12,530,070**	**-**
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**12,530,070**	**-**	**12,530,070**	**-**
4470074		Sale for Resale-Aff-Trnf Price	0	0	332,495,095	0
4540001		Rent From Elect Property - Af	997,029	765,037	0	444,000
	B	**Revenue - Other Ele-Affilliated**	**997,029**	**765,037**	**332,495,095**	**444,000**
4500000		Forfeited Discounts	706,994	706,994	0	0
4510001		Misc Service Rev - Nonaffil	108,776	108,036	0	740
4540002		Rent From Elect Property-NAC	2,827,157	2,350	2,805,532	19,275
4540005		Rent from Elec Prop-Pole Attch	4,171,128	4,164,731	0	6,397
4560007		Oth Elect Rev - DSM Program	375,053	375,053	0	0
5010040		Gas Procuremnt Sales Net	(1,780,042)	0	(1,780,042)	0
		Revenue - Other Ele-NonAffilliated	**6,409,065**	**5,357,163**	**1,025,490**	**26,412**
		Revenue - Gas	-	-	-	-
4118002		Comp. Allow Gains Title IV SO2	14	14	0	0
4118003		Comp. Allow. Gains-Seas NOx	180,714	0	180,714	0
		Gain/(Loss) on Allowances	**180,729**	**14**	**180,714**	**-**
	A	**Revenue - Other Ele-NonAffilliated**	**6,589,794**	**5,357,177**	**1,206,205**	**26,412**
		Revenue - Other Opr Electric	**7,586,823**	**6,122,214**	**333,701,299**	**470,412**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
4170004		Rev from Non-Util Oper NonAfil	279,438	279,438	0	0
	D	**Revenues Non-Utility Operations - NonAffiliated**	**279,438**	**279,438**	**-**	**-**
		Revenues from Non-Utility Operations	**279,438**	**279,438**	**-**	**-**
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operatng Rental Income	1,025	1,025	0	0
4180005		Non-Opratng Rntal Inc-Depr	(5,558)	0	0	(5,558)
	D	**Non-Operating Rental Income - NonAffiliated**	**(4,533)**	**1,025**	**-**	**(5,558)**
		Non-Operating Rental Income	**(4,533)**	**1,025**	**-**	**(5,558)**

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INCOME STATEMENT

IS8016
YTD Oct 2024
11/14/2024 07:55

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Oct 2024	Kentucky Power Company - Distribution 110 Actual YTD Oct 2024	Kentucky Power Company - Generation 117 Actual YTD Oct 2024	Kentucky Power Company - Transmission 180 Actual YTD Oct 2024
C	**Non-Operating Misc Income -Affiliated**	-	-	-	-
4210002	Misc Non-Op Inc-NonAsc-Rents	1,513	475	754	284
4210007	Misc Non-Op Inc - NonAsc - Oth	6,774	993	5,781	0
D	**Non-Operating Misc Income - NonAffiliated**	**8,287**	**1,468**	**6,535**	**284**
	Non-Operating Misc Income	**8,287**	**1,468**	**6,535**	**284**
4540004	Rent From Elect Prop-ABD-Nonaf	1,674	1,674	0	0
4560015	Other Electric Revenues - ABD	529,966	414,484	0	115,482
D	**Associated Business Development Income**	**531,641**	**416,158**	**-**	**115,482**
	Revenue - Other Opr - Other	**814,833**	**698,090**	**6,535**	**110,208**
=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	**-**	**-**	**-**	**-**
=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***814,833***	***698,090***	***6,535***	***110,208***
	Revenue - Other Operating	**8,401,656**	**6,820,304**	**333,707,834**	**580,620**
4491002	Prov Rate Refund-Nonaffiliated	(103,014)	0	0	(103,014)
4491003	Prov Rate Refund - Retail	(22,740)	0	0	(22,740)
A	**Provision for Rate Refund - NonAffiliated**	**(125,754)**	**-**	**-**	**(125,754)**
4491004	Prov Rate Refund - Affiliated	(667,094)	0	0	(667,094)
B	**Provision for Rate Refund - Affiliated**	**(667,094)**	**-**	**-**	**(667,094)**
	Provision for Rate Refund	**(792,848)**	**-**	**-**	**(792,848)**
A	**Revenue - Power Sales**	**-**	**-**	**-**	**-**
	TOTAL OPERATING REVENUES	**574,451,706**	**533,510,974**	**292,224,299**	**149,115,481**
=(A)	*Memo: G/T/D Revenue*	*558,461,218*	*532,047,847*	*10,775,520*	*15,637,850*
=(B)	*Memo: Other Affiliated Revenue*	*15,175,655*	*765,037*	*281,442,243*	*133,367,423*
=(C)	*Memo: Revenue-Oth Opr-Oth Af*	-	-	-	-
=(D)	*Memo: Revenue-Oth Opr-Oth N*	*814,833*	*698,090*	*6,535*	*110,208*
	Memo: Total Operating Revenues	*574,451,706*	*533,510,974*	*292,224,299*	*149,115,481*
=(E)=(B)+(C)	*Memo: Affiliated Revenue*	***15,175,655***	***765,037***	***281,442,243***	***133,367,423***
=(F)=(D)+(A)	*Memo: Non-Affiliated Revenue*	***559,276,051***	***532,745,937***	***10,782,055***	***15,748,058***
	Memo: Total Operating Revenues	***574,451,706***	***533,510,974***	***292,224,299***	***149,115,481***
	FUEL EXPENSES				
5010000	Fuel	5,490,530	2	5,490,526	1
5010001	Fuel Consumed	64,166,304	0	64,166,304	0
5010003	Fuel - Procure Unload & Handle	2,669,797	0	2,669,797	0
5010012	Ash Sales Proceeds	15,673	0	15,673	0
5010013	Fuel Survey Activity	49,281	0	49,281	0
5010019	Fuel Oil Consumed	3,426,611	0	3,426,611	0
5010020	Nat Gas Consumed Steam	24,588,026	0	24,588,026	0
5010021	Transp Gas Consumed Steam	667,036	0	667,036	0
5010027	Gypsum handling/disposal costs	1,136,678	0	1,136,678	0
5010028	Gypsum Sales Proceeds	(1,110,370)	0	(1,110,370)	0
5010034	Gas Transp Res Fees-Steam	5,332,168	0	5,332,168	0
	Fuel Expense Total	**106,431,734**	**2**	**106,431,730**	**1**
5010005	Fuel - Deferred	3,190,865	0	3,190,865	0
	Deferred Fuel Expense	**3,190,865**	**-**	**3,190,865**	**-**
	Over Under Fuel Expense				
	Fuel for Electric Generation	**109,622,599**	**2**	**109,622,595**	**1**
	Fuel from Affiliates for Electric Generation	**-**	**-**	**-**	**-**
5090000	Allow Consum Title IV SO2	31,749	0	31,749	0
5090001	Allowance Consumption - NOx	42,857	0	42,857	0
5090009	Allow Consumpt CSAPR SO2	152	0	152	0

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American Electric Power

IS8016 YTD Oct 2024 11/14/2024 07:55	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024
5570009	Other Pwr Exp- REC's - RETAIL	446	0	446	0
	Allowances - Consumption	**75,205**	**-**	**75,205**	**-**
5020002	Urea Expense	1,004,576	0	1,004,576	0
5020004	Lime-Related Expenses	1,678,026	0	1,678,026	0
	Emissions Control - Chemicals	**2,682,602**	**-**	**2,682,602**	**-**
	Total Fuel for Electric Generation	**112,380,406**	**2**	**112,380,403**	**1**
	Memo: NonAff Fuel/Allow/Emissions	***112,380,406***	***2***	***112,380,403***	***1***
5550004	Purchased Power-Pool Capacity	373,078	0	373,078	0
5550029	Purch Power-Assoc-Trnsfr Price	0	332,495,095	0	0
	Purchased Electricity from AEP - Affiliates	**373,078**	**332,495,095**	**373,078**	**-**
5550001	Purch Pwr-NonTrading-Nonassoc	75,101,853	0	75,101,853	0
5550023	Purch Power Capacity -NA	1,016,160	0	1,016,160	0
5550039	PJM Inadvertent Mtr Res-OSS	5,605	0	5,605	0
5550040	PJM Inadvertent Mtr Res-LSE	59,910	0	59,910	0
5550074	PJM Reactive-Charge	2,990,777	0	2,990,777	0
5550075	PJM Reactive-Credit	(1,195,730)	0	(1,195,730)	0
5550076	PJM Black Start-Charge	906,888	0	906,888	0
5550078	PJM Regulation-Charge	529,654	0	529,654	0
5550079	PJM Regulation-Credit	(13,013)	0	(13,013)	0
5550083	PJM Sync & Non Sync-Charge	428,912	0	428,912	0
5550084	PJM Sync & Non Sync-Credit	(42,497)	0	(42,497)	0
5550123	PJM OpRes-LSE-Charge	1,096,543	0	1,095,217	1,326
5550124	PJM Implicit Congestion-LSE	5,783,557	0	5,783,557	0
5550132	PJM FTR Revenue-LSE	(6,522,722)	0	(6,522,722)	0
5550137	PJM OpRes-LSE-Credit	(56,272)	0	(56,272)	0
5550153	PurchPower-Rockport Def-NonAff	152,680	0	152,680	0
5550326	PJM Transm Loss Charges - LSE	4,615,130	0	4,615,130	0
5550327	PJM Transm Loss Credits-LSE	(1,924,550)	0	(1,924,550)	0
5550328	PJM FC Penalty Credit	(2,883)	0	(2,883)	0
	Purchased Electricity for Resale - NonAffiliated	**82,930,001**	**-**	**82,928,676**	**1,326**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**
8140000	Underground Storage Expenses	1,637	0	1,637	0
	Purchased Gas for Resale - NonAffiliated	**1,637**	**-**	**1,637**	**-**
	Total Purchased Power	**83,304,717**	**332,495,095**	**83,303,391**	**1,326**
	GROSS MARGIN	**378,766,582**	**201,015,877**	**96,540,505**	**149,114,153**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	3,780,151	(11,083)	3,783,421	7,813
5020000	Steam Expenses	1,259,577	0	1,259,577	0
5050000	Electric Expenses	35,703	0	35,703	0
5060000	Misc Steam Power Expenses	5,385,405	61,749	5,316,599	7,057
5060002	Misc Steam Power Exp-Assoc	42,519	0	42,519	0
5060004	NSR Settlement Expense	10,130	0	10,130	0
5060011	BSRR O/U Recovery-Oper Costs	367	0	367	0
	Steam Generation Op Exp	**10,513,852**	**50,667**	**10,448,316**	**14,870**
	Nuclear Generation Op Exp	**-**	**-**	**-**	**-**
	Hydro Generation Op Exp	**-**	**-**	**-**	**-**
5560000	Sys Control & Load Dispatching	56,777	0	56,777	0
5570000	Other Expenses	693,511	0	693,511	0
5570007	Other Pwr Exp - Wholesale RECs	245	245	0	0
5570010	OH Auction Exp - Incremental	6	0	6	0

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IS8016 YTD Oct 2024 11/14/2024 07:55	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
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17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024
5757000	PJM Admin-MAM&SC- OSS	60,360	0	60,360	0
5757001	PJM Admin-MAM&SC- Internal	1,158,817	0	1,158,817	0
	Other Generation Op Exp	**1,969,716**	**245**	**1,969,471**	**-**
5600000	Oper Supervision & Engineering	1,843,458	51,242	19,149	1,773,067
5612000	Load Dispatch-Mntr&Op TransSys	325,104	3,981	536	320,587
5614000	PJM Admin-SSC&DS-OSS	62,969	0	62,969	0
5614001	PJM Admin-SSC&DS-Internal	1,087,970	0	1,087,970	0
5614009	GreenHat Settlement	3,535	0	3,535	0
5615000	Reliability,Plng&Stds Develop	65,883	1,389	191	64,302
5618000	PJM Admin-RP&SDS-OSS	20,311	0	20,311	0
5618001	PJM Admin-RP&SDS- Internal	364,193	0	364,193	0
5620001	Station Expenses - Nonassoc	174,657	(1)	(1)	174,659
5630000	Overhead Line Expenses	25,779	(0)	(0)	25,780
5640000	Underground Line Expenses	16	0	0	16
5650002	Transmssn Elec by Others-NAC	77,711	0	77,711	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	67,691,945	0	0
5650012	PJM Trans Enhancement Charge	1,720,424	0	1,720,424	0
5650015	PJM TO Serv Exp - Aff	137,746	0	137,746	0
5650016	PJM NITS Expense - Affiliated	62,208,003	0	62,208,003	0
5650019	Affil PJM Trans Enhncement Exp	4,582,491	0	4,582,491	0
5650020	PROVISION RTO Affl Expense	(3,511,573)	0	(3,511,573)	0
5650021	PJM NITS Expense - Non-Affilia	722,601	0	722,601	0
5650023	Amort of PROVISION RTO Expense	45,675	0	45,675	0
5660000	Misc Transmission Expenses	1,035,583	118,753	2,736	914,094
5660009	PJM OATT LSE Over-Under Adjust	1,248,885	0	1,248,885	0
5660011	Misc Transm Exp - Affiliate	2,875	0	0	2,875
5670002	Rents - Associated	0	0	0	212,008
	Transmission Op Exp	**72,244,294**	**67,867,310**	**68,793,550**	**3,487,388**
5800000	Oper Supervision & Engineering	837,137	832,871	536	3,775
5810000	Load Dispatching	996	996	0	0
5820000	Station Expenses	314,134	309,726	16	4,392
5830000	Overhead Line Expenses	219,609	219,855	(1)	41
5840000	Underground Line Expenses	292,084	292,427	0	(342)
5850000	Street Lighting & Signal Sys E	32,204	32,207	0	0
5860000	Meter Expenses	1,161,081	1,162,270	(1)	(68)
5870000	Customer Installations Exp	160,018	160,116	0	(35)
5880000	Miscellaneous Distribution Exp	5,358,859	5,351,921	958	6,533
5890001	Rents - Nonassociated	816,098	816,098	0	0
5890002	Rents - Associated	60,351	60,351	0	0
	Distribution Op Exp	**9,252,570**	**9,238,837**	**1,508**	**14,294**
9010000	Supervision - Customer Accts	9,859	9,771	22	66
9020000	Meter Reading Expenses	31,175	31,175	0	0
9020002	Meter Reading - Regular	246,659	246,750	0	0
9020003	Meter Reading - Large Power	21,929	21,929	0	0
9030000	Cust Records & Collection Exp	260,048	257,093	6	2,949
9030001	Customer Orders & Inquiries	2,434,363	2,433,816	166	421
9030002	Manual Billing	8,199	8,168	16	15
9030003	Postage - Customer Bills	520,384	520,384	0	0
9030004	Cashiering	44,594	44,594	0	0
9030005	Collection Agents Fees & Exp	2,710	2,710	0	0
9030006	Credit & Oth Collection Activi	532,831	533,235	0	0

American Electric Power

IS8016 YTD Oct 2024 11/14/2024 07:55	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024
9030007	Collectors	266,437	266,437	0	0
9030009	Data Processing	30,109	30,102	5	5
9040007	Uncoll Accts - Misc Receivable	17,258	17,235	1	22
9050000	Misc Customer Accounts Exp	16,700	16,700	0	0
9070000	Supervision - Customer Service	48,872	48,834	10	33
9080000	Customer Assistance Expenses	1,071,988	1,072,024	0	0
9080009	Cust Assistance Expense - DSM	397,668	397,671	0	0
9100000	Misc Cust Svc&Informational Ex	4,583	2,164	1,238	1,181
	Customer Service and Information Op Exp	**5,966,365**	**5,960,792**	**1,463**	**4,692**
9120000	Demonstrating & Selling Exp	8,598	8,594	1	3
9120003	Demo & Selling Exp - Area Dev	36	36	0	0
9130001	Advertising Exp - Residential	80	72	7	1
	Sales Expenses	**8,713**	**8,701**	**8**	**4**
	Memo: Insurance (9240 9250)	**2,651,542**	**1,425,654**	**982,400**	**243,489**
9200000	Administrative & Gen Salaries	10,641,858	5,089,141	3,877,194	1,675,533
9210001	Off Supl & Exp - Nonassociated	607,218	363,925	171,765	71,578
9210003	Office Supplies & Exp - Trnsf	180	80	68	32
9210020	EMP RECOG - Over 100 Dollars	2	2	1	0
9210021	EMP TRAVEL - Airfare	111	50	46	15
9210022	MEALS & ENT-100 Pct DEDUCTIBLE	109	45	51	13
9210023	EMP TRAVEL-MILEAGE	585	309	183	94
9210024	EMP TRAVEL-PARKING	14	7	5	1
9210025	MEALS & ENT-50 Pct DEDUCTIBLE	46	28	16	2
9210026	EMP TRAVEL-CAR RENTAL	29	17	11	2
9210027	EMP TRAVEL-TAXI AND SHUTTLE	14	7	5	1
9210028	EMP TRAVEL-HOTEL & LODGING	639	240	323	76
9210030	EMP TRAVEL-OTHER	122	92	29	1
9210031	SAFETY EQUIPMENT AND SUPPLIES	7	2	4	1
9210032	FUEL	10	7	3	0
9210033	FOOD SERVICE-CATERING	9	3	4	2
9210034	In-House Training & Seminars	106	0	0	106
9210037	OEM/TECHNICAL TRAINING	263	3	1	259
9210040	DUES-BUSINESS/PROFESSIONAL	63	21	29	13
9210041	VEHICLE-LICENSE FEES	12	4	5	3
9220000	Administrative Exp Trnsf - Cr	(201,204)	(201,204)	(0)	(0)
9220001	Admin Exp Trnsf to Cnstrction	(390,555)	(390,555)	0	0
9220002	Admin Exp Trnsf Const-Mngerial	0	(0)	0	0
9220004	Admin Exp Trnsf to ABD	(263)	(263)	0	0
9220005	Overhead Loadings	(581,361)	(386,704)	(166,069)	(28,588)
9230001	Outside Svcs Empl - Nonassoc	3,586,389	1,089,072	1,262,565	1,234,752
9230003	AEPSC Billed to Client Co	(114,136)	(46,781)	(54,881)	(12,474)
9230024	SRV-MAIL/MESSENGER-POSTAGE	1	1	0	0
9230031	SRV-OUTSIDE SERVICES (TECH)	112	37	52	23
9230034	SRV-SOFTWARE LICENSING	14,962	10,978	3,859	125
9230035	Development Project Expense	116	0	0	116
9240000	Property Insurance	973,522	237,561	569,191	166,769
9250000	Injuries and Damages	1,523,896	1,055,178	394,892	73,826
9250002	Emp Accdent Prvntion-Adm Exp	206	71	72	63
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	303,607	268,574	31,345	3,688
9250007	Prsnal Injries&Prop Dmage-Pub	22,469	0	22,469	0
9250010	Frg Ben Loading - Workers Comp	(172,156)	(135,730)	(35,569)	(857)

American Electric Power

IS8016 YTD Oct 2024 11/14/2024 07:55	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024
9260000	Employee Pensions & Benefits	2,138	2,138	0	0
9260001	Edit & Print Empl Pub-Salaries	86	33	37	16
9260002	Pension & Group Ins Admin	25,042	11,502	13,152	388
9260003	Pension Plan	1,782,440	1,195,236	573,453	13,751
9260004	Group Life Insurance Premiums	108,753	71,684	36,451	618
9260005	Group Medical Ins Premiums	4,060,868	2,751,208	1,273,749	35,911
9260007	Group L-T Disability Ins Prem	408,229	295,085	112,752	393
9260009	Group Dental Insurance Prem	142,624	96,910	44,349	1,364
9260010	Training Administration Exp	1,161	480	403	278
9260012	Employee Activities	13,077	10,464	2,168	446
9260021	Postretirement Benefits - OPEB	77,005	41,937	34,005	1,064
9260027	Savings Plan Contributions	1,531,096	1,011,579	508,415	11,103
9260036	Deferred Compensation	8,845	8,845	0	0
9260037	Supplemental Pension	20,710	20,661	49	0
9260050	Frg Ben Loading - Pension	(780,139)	(664,328)	(104,557)	(11,254)
9260051	Frg Ben Loading - Grp Ins	(2,115,912)	(1,800,234)	(288,112)	(27,567)
9260052	Frg Ben Loading - Savings	(665,057)	(562,710)	(92,155)	(10,191)
9260053	Frg Ben Loading - OPEB	(80,889)	(65,213)	(14,456)	(1,220)
9260055	IntercoFringeOffset- Don't Use	(382,832)	(382,832)	0	0
9260058	Frg Ben Loading - Accrual	(144,733)	(81,008)	(61,585)	(2,141)
9260060	Amort-Post Retirerment Benefit	180,517	107,984	59,339	13,194
9270000	Franchise Requirements	135,618	134,276	699	644
9280000	Regulatory Commission Exp	8,816	3,805	2,641	2,369
9280001	Regulatory Commission Exp-Adm	4,351	4,186	160	5
9280002	Regulatory Commission Exp-Case	2,341,750	1,206,225	556,365	579,164
9280005	Reg Com Exp-FERC Trans Cases	19,442	403	437	18,603
9280006	State Publ Serv CommissionFees	792,331	792,331	0	0
9301000	General Advertising Expenses	24,314	10,798	7,021	6,495
9301001	Newspaper Advertising Space	20,262	9,134	5,651	5,476
9301003	TV Station Advertising Time	24,302	10,947	6,929	6,426
9301012	Public Opinion Surveys	12,539	12,538	1	1
9301015	Other Corporate Comm Exp	5,508	5,508	0	0
9302000	Misc General Expenses	232,609	91,494	91,415	49,700
9302003	Corporate & Fiscal Expenses	83,336	46,542	28,848	7,947
9302004	Research, Develop&Demonstr Exp	584	201	286	98
9310001	Rents - Real Property	8,000	8,000	0	0
9310002	Rents - Personal Property	44,011	36,500	6,812	699
	Administration & General	**24,167,805**	**11,396,528**	**8,882,387**	**3,888,954**
4111005	Accretion Expense	1,042,252	12,976	1,029,276	0
	Accretion	**1,042,252**	**12,976**	**1,029,276**	**-**
4116000	Gain From Disposition of Plant	(12,097)	(12,097)	0	0
	Loss/(Gain) on Utility Plant	**(12,097)**	**(12,097)**	**-**	**-**
9302006	Assoc Bus Dev - Materials Sold	120,525	120,525	0	0
9302007	Assoc Business Development Exp	164,615	133,519	184	30,920
	Associated Business Development Expenses	**285,140**	**254,044**	**184**	**30,920**
	Gain on Disposition of Property	**-**	**-**	**-**	**-**
4212000	Loss on Dspsition of Property	174	0	174	0
	Loss on Disposition of Property	**174**	**-**	**174**	**-**
	Loss(Gain) of Sale of Property	**174**	**-**	**174**	**-**
4265009	Factored Cust A/R Exp - Affil	2,733,252	2,733,252	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	1,604,391	1,604,391	0	0

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INCOME STATEMENT

IS8016
YTD Oct 2024
11/14/2024 07:55

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Oct 2024	Kentucky Power Company - Distribution 110 Actual YTD Oct 2024	Kentucky Power Company - Generation 117 Actual YTD Oct 2024	Kentucky Power Company - Transmission 180 Actual YTD Oct 2024
	Opr Exp and Factored A/R	**4,337,643**	**4,337,643**	**-**	**-**
	Water Heaters	**-**	**-**	**-**	**-**
4040007	Cloud Implement - Amort Plant	364,440	256,719	67,529	40,192
4171006	Outside Services - Other	630	630	0	0
4265004	Social & Service Club Dues	37,919	15,823	20,022	2,074
4265007	Regulatory Expenses	4,353	1,943	1,246	1,164
	Expense of Non-Utility Operation	**407,343**	**275,116**	**88,797**	**43,430**
4210009	Misc Non-Op Exp - NonAssoc	16,985	16,737	107	142
	Misc NonOp Expenses - NonAssoc	**16,985**	**16,737**	**107**	**142**
4261000	Donations	1,356,104	1,342,558	7,324	6,223
	Donation Contributions	**1,356,104**	**1,342,558**	**7,324**	**6,223**
4263001	Penalties	2,064	843	890	331
	Provision for Penalties	**2,064**	**843**	**890**	**331**
4264000	Civic and Political Activity	178,542	91,308	44,798	42,439
4264001	Non-deduct Lobbying per IRS	14,223	4,883	6,467	2,873
	Civic & Political Activities	**192,766**	**96,191**	**51,266**	**45,312**
4265002	Other Deductions - Nonassoc	352,235	316,380	25,162	10,693
	Other Deductions	**352,235**	**316,380**	**25,162**	**10,693**
	Shutdown Coal Company Expenses	**-**	**-**	**-**	**-**
	All Other Operational Expenses	**6,665,140**	**6,385,467**	**173,545**	**106,130**
	Operational Expenses	**132,103,924**	**101,163,470**	**91,299,882**	**7,547,252**
5100000	Maint Supv & Engineering	1,474,450	0	1,474,448	2
5110000	Maintenance of Structures	1,583,589	0	1,583,589	0
5120000	Maintenance of Boiler Plant	12,113,008	0	12,113,008	0
5120034	BSDR O/U Recovery - Maint Cost	(8,644)	0	(8,644)	0
5120037	KY Steam Maint O/U	(546,405)	0	(546,405)	0
5130000	Maintenance of Electric Plant	3,402,093	0	3,402,093	0
5140000	Maintenance of Misc Steam Plt	1,312,009	0	1,312,009	0
5140025	Maint MiscStmPlt Environmental	(14)	0	(14)	0
	Steam Generation Maintenance	**19,330,086**	**-**	**19,330,085**	**2**
	Nuclear Generation Maintenance	**-**	**-**	**-**	**-**
	Hydro Generation Maintenance	**-**	**-**	**-**	**-**
	Other Generation Maintenance	**-**	**-**	**-**	**-**
5680000	Maint Supv & Engineering	20,704	913	729	19,062
5690000	Maintenance of Structures	32,355	0	0	32,355
5691000	Maint of Computer Hardware	6,524	101	13	6,410
5692000	Maint of Computer Software	184,282	11,379	6,227	166,676
5693000	Maint of Communication Equip	10,261	314	0	9,947
5700000	Maint of Station Equipment	416,990	1,764	3	415,223
5710000	Maintenance of Overhead Lines	4,871,462	(5)	0	4,871,470
5720000	Maint of Underground Lines	547	0	0	547
5730000	Maint of Misc Trnsmssion Plt	2,531	50	5	2,476
	Transmission Maintenance	**5,545,655**	**14,516**	**6,976**	**5,524,166**
5900000	Maint Supv & Engineering	13,061	12,828	0	233
5910000	Maintenance of Structures	9,641	9,632	0	9
5920000	Maint of Station Equipment	827,572	820,536	61	6,975
5930000	Maintenance of Overhead Lines	32,925,630	32,926,948	484	4,921
5930001	Tree and Brush Control	351,587	351,533	0	0
5940000	Maint of Underground Lines	34,691	34,699	0	0
5950000	Maint of Lne Trnf,Rglators&Dvi	14,867	14,875	0	0
5960000	Maint of Strt Lghtng & Sgnal S	8,580	8,581	0	0

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IS8016 YTD Oct 2024 11/14/2024 07:55	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024
5970000	Maintenance of Meters	30,644	30,672	0	(0)
5980000	Maint of Misc Distribution Plt	26,510	26,504	1	6
	Distribution Maintenance	**34,242,783**	**34,236,808**	**547**	**12,143**
9350000	Maintenance of General Plant	21,702	16,866	4,836	0
9350001	Maint of Structures - Owned	759,929	751,726	5,374	2,829
9350002	Maint of Structures - Leased	8,111	6,521	548	1,042
9350012	Maint of Data Equipment	3,789	2,812	977	0
9350013	Maint of Cmmncation Eq-Unall	939,680	907,044	33,325	0
9350015	Maint of Office Furniture & Eq	812,104	395,051	417,053	0
9350023	Site Communications Services	98	72	26	0
9350024	Maint of DA-AMI Comm Equip	4,717	4,424	103	192
	Administration & General Maintenance	**2,550,130**	**2,084,516**	**462,242**	**4,063**
	All Other Maintenance Expenses	**-**	**-**	**-**	**-**
	Maintenance Expenses	**61,668,654**	**36,335,840**	**19,799,850**	**5,540,374**
	Total Operational and Maintenance Expenses	**193,772,578**	**137,499,310**	**111,099,731**	**13,087,625**
4040001	Amort. of Plant	7,725,477	3,854,952	2,647,032	1,223,493
4060001	Amort of Plt Acq Adj	32,180	0	0	32,180
	DDA Amortization	**7,757,657**	**3,854,952**	**2,647,032**	**1,255,673**
4073000	Regulatory Debits	(0)	0	(0)	0
4073014	Regulatory Debit - BSDR	336,414	0	336,414	0
	DDA Regulatory Debits	**336,413**	**-**	**336,413**	**-**
4074000	Regulatory Credits	(800,211)	(40,681)	(759,530)	0
4074025	PPA RIDER Over/Under	3,411,483	0	3,411,483	0
	DDA Regulatory Credits	**2,611,272**	**(40,681)**	**2,651,953**	**-**
	Amortization	**10,705,342**	**3,814,271**	**5,635,399**	**1,255,673**
4030001	Depreciation Exp	88,135,283	37,346,365	30,885,740	19,903,177
4030029	Over/Undr Depr Exp Var Riders	(2,470,285)	0	(2,470,285)	0
	DDA Depreciation	**85,664,998**	**37,346,365**	**28,415,455**	**19,903,177**
	DDA STP Nuclear Decommissioning	**-**	**-**	**-**	**-**
4031001	Depr - Asset Retirement Oblig	891,106	8,145	882,961	0
	DDA Asset Retirement Obligation	**891,106**	**8,145**	**882,961**	**-**
	DDA Removal Costs	**-**	**-**	**-**	**-**
	Depreciation	**86,556,103**	**37,354,510**	**29,298,416**	**19,903,177**
	Depreciation and Amortization	**97,261,446**	**41,168,781**	**34,933,814**	**21,158,850**
	Franchise Taxes	**-**	**-**	**-**	**-**
408100624	State Gross Receipts Tax	16,496	3	16,493	0
	Revenue-kWhr Taxes	**16,496**	**3**	**16,493**	**-**
4081002	FICA	3,020,427	2,073,097	928,495	18,835
4081003	Federal Unemployment Tax	13,322	8,339	4,891	92
4081007	State Unemployment Tax	23,282	8,378	14,821	83
4081033	Fringe Benefit Loading - FICA	(1,242,771)	(1,054,087)	(170,385)	(18,300)
4081034	Fringe Benefit Loading - FUT	(5,877)	(4,958)	(813)	(106)
4081035	Fringe Benefit Loading - SUT	(6,412)	(3,900)	(2,339)	(173)
	Payroll Taxes	**1,801,973**	**1,026,870**	**774,672**	**431**
408102022	State Business Occup Taxes	(28,789)	0	(28,789)	0
408102023	State Business Occup Taxes	8,974	0	8,974	0
408102024	State Business Occup Taxes	6,141,564	0	6,141,564	0
	Capacity Taxes	**6,121,749**	**-**	**6,121,749**	**-**
408100521	Real Personal Property Taxes	832,990	778,009	7	54,974

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IS8016 YTD Oct 2024 11/14/2024 07:55	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024
408100522	Real Personal Property Taxes	1,560,190	(10)	1,560,200	0
408100523	Real Personal Property Taxes	18,435,913	9,599,614	2,843,318	5,992,980
408102922	Real-Pers Prop Tax-Cap Leases	(372,463)	(187,830)	(5,727)	(178,907)
408102923	Real-Pers Prop Tax-Cap Leases	(832)	0	(832)	0
408102924	Real-Pers Prop Tax-Cap Leases	514,329	482,690	19,619	12,020
408103623	Real Prop Tax-Cap Leases	7,431	7,431	0	0
408103624	Real Prop Tax-Cap Leases	11,340	11,340	0	0
408200523	Real Personal Property Taxes	42,106	80	41,261	765
408200524	Real Personal Property Taxes	22,168	0	22,168	0
	Property Taxes	**21,053,172**	**10,691,325**	**4,480,014**	**5,881,833**
	Regulatory Fees	**-**	**-**	**-**	**-**
408101423	Federal Excise Taxes	725	0	725	0
408101424	Federal Excise Taxes	13,915	0	13,915	0
	Production Taxes	**14,640**	**-**	**14,640**	**-**
408101923	State Sales and Use Taxes	1,530	1,530	0	0
408101924	State Sales and Use Taxes	43,514	10,507	33,007	0
	Miscellaneous Taxes	**45,044**	**12,038**	**33,007**	**-**
	Other Non-Income Taxes	**59,684**	**12,038**	**47,647**	**-**
	Taxes Other Than Income Taxes	**29,053,074**	**11,730,236**	**11,440,575**	**5,882,264**
	TOTAL OPERATING EXPENSES	**320,087,097**	**190,398,327**	**157,474,120**	**40,128,739**
	Memo: SEC Total Operating Expenses	**515,772,221**	**522,893,424**	**353,157,914**	**40,130,067**
	OPERATING INCOME	**58,679,485**	**10,617,550**	**(60,933,615)**	**108,985,414**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	145,066	6,129	138,937	0
	Interest & Dividend NonAffiliated	**145,066**	**6,129**	**138,937**	**-**
4190005	Interest Income - Assoc CBP	309	309	0	0
	Interest & Dividend Affiliated	**309**	**309**	**-**	**-**
	Total Interest & Dividend Income	**145,374**	**6,437**	**138,937**	**-**
	Interest & Dividend Carrying Charge	**-**	**-**	**-**	**-**
	Memo: Total Interest & Dividend Income w/ Carrying	**145,374**	**6,437**	**138,937**	**-**
9260042	SERP Pension - Non-Service	(3,221)	(3,203)	(18)	0
9260043	OPEB - Non-Service	2,328,186	923,565	1,334,274	70,348
9260062	Pension Plan - Non-Service	3,419,674	900,515	2,578,165	(59,006)
	Other Components of Net Periodic Pension	**5,744,639**	**1,820,877**	**3,912,421**	**11,342**
4191000	Allw Oth Fnds Usd Drng Cnstr	1,938,976	478,224	393,493	1,067,259
	AFUDC	**1,938,976**	**478,224**	**393,493**	**1,067,259**
	Gain on Disposition of Equity Investments	**-**	**-**	**-**	**-**
	Interest LTD FMB	**-**	**-**	**-**	**-**
4270002	Int on LTD - Install Pur Contr	(2,545,833)	(2,545,833)	0	0
	Interest LTD IPC	**(2,545,833)**	**(2,545,833)**	**-**	**-**
4300001	Interest Exp - Assoc Non-CBP	(841,257)	(841,257)	0	0
	Interest LTD Notes Payable - Affiliated	**(841,257)**	**(841,257)**	**-**	**-**
	Interest LTD Notes Payable - NonAffiliated	**-**	**-**	**-**	**-**
	Interest LTD Debentures	**-**	**-**	**-**	**-**
4270006	Int on LTD - Sen Unsec Notes	(47,697,040)	(47,697,040)	0	0
	Interest LTD Senior Unsecured	**(47,697,040)**	**(47,697,040)**	**-**	**-**
	Interest LTD Other - Affil	**-**	**-**	**-**	**-**

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IS8016 YTD Oct 2024 11/14/2024 07:55	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024
4270005	Int on LTD - Other LTD	(8,058,480)	(8,058,480)	0	0
	Interest LTD Other - NonAffil	**(8,058,480)**	**(8,058,480)**	**-**	**-**
	Interest on Long-Term Debt	**(59,142,611)**	**(59,142,611)**	**-**	**-**
4300003	Int to Assoc Co - CBP	(3,758,377)	34,105,871	(48,842,675)	10,978,427
	Interest STD - Affil	**(3,758,377)**	**34,105,871**	**(48,842,675)**	**10,978,427**
4310007	Lines Of Credit	(569,874)	(254,298)	(206,944)	(108,633)
	Interest STD - NonAffil	**(569,874)**	**(254,298)**	**(206,944)**	**(108,633)**
	Interest on Short Term Debt	**(4,328,251)**	**33,851,573**	**(49,049,619)**	**10,869,794**
4280002	Amrtz Debt Dscnt&Exp-Instl Pur	(143,097)	(143,097)	0	0
4280003	Amrtz Debt Dscnt&Exp-N/P	(9,637)	(9,637)	0	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	(495,284)	(495,284)	0	0
	Amort of Debt Disc. Prem & Exp	**(648,018)**	**(648,018)**	**-**	**-**
4281004	Amrtz Loss Rcquired Debt-Dbnt	(28,042)	(28,042)	0	0
	Amort Loss on Reacquired Debt	**(28,042)**	**(28,042)**	**-**	**-**
	Amort Gain on Reacquired Debt	**-**	**-**	**-**	**-**
	Other Interest - Fuel Recovery	**-**	**-**	**-**	**-**
4310001	Other Interest Expense	9,517,721	19,660	9,486,446	11,615
4310002	Interest on Customer Deposits	(1,688,675)	(1,688,675)	0	0
9310005	Int on Regulated Fin Leases	(10,137)	0	0	0
	Other Interest - NonAffil	**7,818,910**	**(1,669,015)**	**9,486,446**	**11,615**
	Other Interest Expense - Affil	**-**	**-**	**-**	**-**
	Interest Rate Hedge Unrealized (Gain)/Loss	**-**	**-**	**-**	**-**
4320000	Allw Brrwed Fnds Used Cnstr-Cr	3,126,870	788,105	602,279	1,736,486
	AFUDC-Borrowed Funds	**3,126,870**	**788,105**	**602,279**	**1,736,486**
	Total Interest Charges	**(53,201,142)**	**(26,848,008)**	**(38,960,893)**	**12,617,895**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**13,307,332**	**(13,924,920)**	**(95,449,658)**	**122,681,910**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	222,421	(6,327,068)	(16,016,285)	22,565,774
4092001	Inc Tax, Oth Inc&Ded-Federal	(383,797)	(307,174)	(80,427)	3,804
	Federal Current Income Tax	**(161,375)**	**(6,634,241)**	**(16,096,712)**	**22,569,578**
4101001	Prov Def I/T Util Op Inc-Fed	47,951,461	11,821,569	30,879,168	5,250,724
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(50,622,430)	(8,403,560)	(38,292,389)	(3,926,481)
	Federal Deferred Income Tax	**(2,670,968)**	**3,418,009**	**(7,413,220)**	**1,324,243**
	Federal Investment Tax Credits	**-**	**-**	**-**	**-**
	Federal Income Taxes	**(2,832,344)**	**(3,216,232)**	**(23,509,932)**	**23,893,821**
4091002	Income Taxes, UOI - State	(399,514)	(539,910)	(1,369,297)	1,509,693
409100223	Income Taxes UOI - State	(255,377)	(1,814,309)	(2,126,994)	3,685,926
4092002	Inc Tax, Oth Inc & Ded - State	(26,396)	(19,438)	(8,143)	1,185
409200223	Inc Tax Oth Inc Ded - State	(69,925)	(57,653)	(12,042)	(231)
	State Current Income Tax	**(751,212)**	**(2,431,310)**	**(3,516,475)**	**5,196,573**
4111002	Prv Def I/T-Cr UtilOpInc-State	(909,273)	0	(909,273)	0
	State Deferred Income Tax	**(909,273)**	**-**	**(909,273)**	**-**
	State Investment Tax Credits	**-**	**-**	**-**	**-**
	State Income Taxes	**(1,660,486)**	**(2,431,310)**	**(4,425,749)**	**5,196,573**
	Local Current Income Tax	**-**	**-**	**-**	**-**
	Local Deferred Income Tax	**-**	**-**	**-**	**-**
	Local Investment Tax Credits	**-**	**-**	**-**	**-**
	Local Income Taxes	**-**	**-**	**-**	**-**
	Foreign Current Income Tax	**-**	**-**	**-**	**-**

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IS8016 YTD Oct 2024 11/14/2024 07:55	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024
	Foreign Deferred Income Tax	-	-	-	-
	Foreign Investment Tax Credits	-	-	-	-
	Foreign Income Taxes	-	-	-	-
	Total Income Taxes	(4,492,830)	(5,647,543)	(27,935,681)	29,090,394
	Equity Earnings of Subs	-	-	-	-
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	17,800,162	(8,277,377)	(67,513,977)	93,591,516
	Discontinued Operations (Net of Taxes)	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-
	NET INCOME	17,800,162	(8,277,377)	(67,513,977)	93,591,516
	Minority Interest	-	-	-	-
	Preferred Stock Dividend Subs	-	-	-	-
	Earnings to Common Shareholders	17,800,162	(8,277,377)	(67,513,977)	93,591,516
	NET INCOME (LOSS) NODE before PS	17,800,162	(8,277,377)	(67,513,977)	93,591,516
	Double Check on Net Income Node after PS	-	0	-	-

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BS8216 YTD Oct 2024 11/14/2024 07:37	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024
	ASSETS				
	Cash and Cash Equivalents	**624,930**	**624,930**	**0**	**0**
	Other Cash Deposits	**19,180**	**9,413**	**9,500**	**267**
	Customers	11,853,768	8,513,299	846,703	2,493,765
	Accrued Unbilled Revenues	(1,184,034)	(1,184,034)	0	0
	Miscellaneous Accounts Receivable	15,518,224	12,041,218	41,287,209	15,917,157
	Allowances for Uncollectible Accounts	(270)	(250)	0	(20)
	Accounts Receivable	**26,187,688**	**19,370,234**	**42,133,912**	**18,410,903**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**91,615,200**	**6,456,104**	**81,728,687**	**3,430,409**
	Risk Management Contracts - Current	**7,747,518**	**0**	**7,747,518**	**0**
	Margin Deposits	**5,548,852**	**51,829**	**5,497,023**	**0**
	Unrecovered Fuel - Current	**7,496,939**	**0**	**7,496,939**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**5,542,214**	**4,671,547**	**632,695**	**237,972**
	TOTAL CURRENT ASSETS	**144,782,521**	**31,184,056**	**145,246,274**	**22,079,551**
	Electric Production	**1,281,960,691**	**1,304,780,999**	**1,317,129,746**	**883,529,098**
	Electric Transmission	**878,950,788**	**0**	**0**	**0**
	Electric Distribution	**1,170,913,982**	**0**	**0**	**0**
	General Property, Plant and Equipment	**174,771,916**	**83,276**	**(45,138)**	**1,119,396**
	Construction Work-in-Progress	**186,641,307**	**59,302,338**	**8,947,341**	**118,391,627**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,693,238,684**	**1,364,166,613**	**1,326,031,950**	**1,003,040,121**
	less: Accumulated Depreciation and Amortization	**(1,246,921,702)**	**(331,427,967)**	**(649,034,174)**	**(266,459,561)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,446,316,982**	**1,032,738,647**	**676,997,775**	**736,580,559**
	Net Regulatory Assets	**610,095,859**	**136,503,761**	**463,431,891**	**10,160,207**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Assets	**26,685,630**	**13,908,683**	**11,996,630**	**780,316**
	Other Non Current Assets	**29,382,641**	**7,048,453**	**20,174,991**	**2,159,197**
	TOTAL OTHER NON-CURRENT ASSETS	**666,164,129**	**157,460,897**	**495,603,513**	**13,099,720**
	TOTAL ASSETS	**3,257,263,632**	**1,221,383,599**	**1,317,847,562**	**771,759,830**
	LIABILITIES				
	Accounts Payable	**125,706,139**	**82,208,829**	**73,445,673**	**23,778,997**
	Advances from Affiliates	**147,344,429**	**(640,753,936)**	**1,054,670,109**	**(266,571,744)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**150,000,000**	**150,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	6,004,538	53,840	5,950,698	0
2440021	S/T Liability MTM Collateral	(773,613)	(66,412)	(707,201)	0
	Risk Management Liabilities - MTM	5,230,925	(12,572)	5,243,497	0
	Risk Management Liabilities	**5,230,925**	**(12,572)**	**5,243,497**	**0**
	Accrued Taxes	**17,146,568**	**(5,026,811)**	**(44,409,407)**	**66,582,786**

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	BALANCE SHEET	Kentucky Power Int Consol	Kentucky Power Company - Distribution	Kentucky Power Company - Generation	Kentucky Power Company - Transmission
		BS8216	110	117	180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024
	Memo: Property Taxes	29,041,341	16,252,293	4,530,749	8,258,299
	Accrued Interest	**22,479,511**	**22,479,511**	**0**	**0**
	Risk Management Collateral	496,705	0	496,705	0
	Utility Customer Deposits	37,608,066	37,608,066	0	0
	Deposits - Customer and Collateral	**38,104,771**	**37,608,066**	**496,705**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	129,552	50,284	79,268	0
	Obligations under Operating Leases - Current	230,108	95,954	62,854	71,300
	Tax Collections Payable	1,588,084	1,588,084	0	0
	Revenue Refunds - Accrued	394,291	0	133,025	261,266
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	995,204	851,074	134,612	9,518
	Accrued Rents	(5,710)	(5,710)	0	0
	Accrued ICP	1,698,328	1,566,790	124,821	6,716
	Accrued Vacations	2,387,928	2,130,638	235,084	22,206
	Misc Employee Benefits	1,281,769	1,090,264	188,824	2,681
	Payroll Deductions	94,671	83,772	9,635	1,264
	Severance / SEI	728	728	0	0
	Accrued Workers Compensation	242,772	241,530	1,242	0
2530022	Customer Advance Receipts	2,808,596	2,808,596	0	0
	Customer Advance	2,808,596	2,808,596	0	0
2420511	Control Cash Disburse Account	4,423,871	4,423,871	0	0
	Control Cash Disbursement Account	4,423,871	4,423,871	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	118,665	0	118,665	0
2300002	ARO - Current	1,442,506	0	1,442,506	0
2420088	Econ. Development Fund Curr	500,646	500,646	0	0
2420512	Unclaimed Funds	16,001	16,001	0	0
2420542	Acc Cash Franchise Req	65,733	65,733	0	0
2420643	Accrued Audit Fees	21,767	9,187	8,186	4,394
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	283,242	282,582	0	661
2530112	Other Deferred Credits-Curr	1,847	1,847	0	0
2530124	Contr In Aid of Constr Advance	619,135	619,135	0	0
	Misc Current and Accrued Liabilities	3,070,226	1,495,816	1,569,356	5,054
	Current Other and Accrued Liabilities	18,980,758	16,275,453	2,396,599	308,706
	Other Current Liabilities	**19,340,418**	**16,421,691**	**2,538,721**	**380,006**
	TOTAL CURRENT LIABILITIES	**525,352,761**	**(337,075,222)**	**1,091,985,299**	**(175,829,956)**
	Long-Term Debt - Affiliated	**0**	**0**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,060,981,707**	**1,060,981,707**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(604,125)**	**(604,125)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,060,377,582*	*1,060,377,582*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	429,053	5,703	423,350	0
2440022	L/T Liability MTM Collateral	(24,223)	(11,332)	(12,891)	0
	Long-Term Risk Management Liabilities - MTM	404,830	(5,629)	410,459	0
	Long-Term Risk Management Liabilities	**404,830**	**(5,629)**	**410,459**	**0**

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BS8216 YTD Oct 2024 11/14/2024 07:37	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024	YTD Oct 2024
	Deferred Income Taxes	**480,716,109**	**169,586,608**	**216,953,082**	**94,176,419**
	Deferred Investment Tax Credits	**0**	**0**	**0**	**0**
	Regulatory Liabilities and Deferred Credits	**116,382,490**	**86,538,779**	**(3,809,497)**	**33,653,208**
	Memo - Reg Liab and Def ITC	*116,382,490*	*86,538,779*	*(3,809,497)*	*33,653,208*
	Asset Retirement Obligation	**86,648,325**	**214,040**	**86,434,285**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**7,182,205**	**11,129,143**	**(5,725,130)**	**1,778,192**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redempt	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	722,113	553,862	168,252	0
	Obligations Under Operating Leases	1,764,230	1,288,934	184,032	291,265
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	99,203	99,203	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	28,310	28,310	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	222	0	0	222
2530185	O\U Accounting of ExpensesT	3,767	0	3,767	0
2530188	Long Term Assoc AP	3,781,087	0	0	3,781,087
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	3,898,001	28,310	3,767	3,865,924
	Total Other Deferred Credits	3,997,204	127,513	3,767	3,865,924
	Accumulated Provisions - Rate Refund	687,793	0	0	687,793
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**7,171,341**	**1,970,309**	**356,050**	**4,844,982**
	TOTAL NON-CURRENT LIABILITIES	**1,758,882,883**	**1,329,810,832**	**294,619,249**	**134,452,801**
	TOTAL LIABILITIES	**2,284,235,644**	**992,735,610**	**1,386,604,548**	**(41,377,154)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**527,243,589**	**106,025,371**	**336,531,464**	**84,686,754**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**395,334,399**	**100,218,569**	**(415,576,053)**	**710,691,883**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**973,027,988**	**228,647,989**	**(68,756,985)**	**813,136,985**
	Memo: Total Equity	973,027,988	228,647,989	(68,756,985)	813,136,985
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,257,263,632**	**1,221,383,599**	**1,317,847,562**	**771,759,830**

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BS8216 YTD Oct 2023 11/09/2023 18:08	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Oct 2023	YTD Oct 2023	YTD Oct 2023	YTD Oct 2023
	ASSETS				
	Cash and Cash Equivalents	**1,706,354**	**1,706,354**	**0**	**0**
	Other Cash Deposits	**55,764**	**22,325**	**32,470**	**969**
	Customers	12,949,445	10,439,679	1,450,281	1,059,485
	Accrued Unbilled Revenues	4,515,239	4,515,239	0	0
	Miscellaneous Accounts Receivable	14,952,025	3,632,875	44,072,007	14,917,550
	Allowances for Uncollectible Accounts	(88,797)	(254)	(3)	(88,540)
	Accounts Receivable	**32,327,913**	**18,587,540**	**45,522,284**	**15,888,495**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**97,949,434**	**8,068,913**	**87,400,232**	**2,480,289**
	Risk Management Contracts - Current	**7,256,824**	**0**	**7,256,824**	**0**
	Margin Deposits	**119,548**	**0**	**119,548**	**0**
	Unrecovered Fuel - Current	**4,708,865**	**0**	**4,708,865**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**3,043,813**	**2,341,803**	**489,326**	**212,684**
	TOTAL CURRENT ASSETS	**147,168,515**	**30,726,935**	**145,529,550**	**18,582,437**
	Electric Production	**1,240,948,833**	**1,233,118,528**	**1,279,041,020**	**824,712,787**
	Electric Transmission	**820,941,390**	**0**	**0**	**0**
	Electric Distribution	**1,102,691,265**	**0**	**0**	**0**
	General Property, Plant and Equipment	**173,517,726**	**83,276**	**24,208**	**1,119,396**
	Construction Work-in-Progress	**176,459,358**	**66,773,556**	**24,685,179**	**85,000,623**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,514,558,573**	**1,299,975,360**	**1,303,750,406**	**910,832,806**
	less: Accumulated Depreciation and Amortization	**(1,197,195,007)**	**(317,616,107)**	**(625,257,380)**	**(254,321,520)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,317,363,566**	**982,359,254**	**678,493,027**	**656,511,285**
	Net Regulatory Assets	**535,612,758**	**128,662,463**	**400,118,111**	**6,832,184**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**357,182**	**0**	**357,182**	**0**
	Employee Benefits and Pension Assets	**22,201,118**	**11,650,650**	**9,993,023**	**557,445**
	Other Non Current Assets	**19,203,649**	**4,902,134**	**13,175,115**	**1,126,401**
	TOTAL OTHER NON-CURRENT ASSETS	**577,374,708**	**145,215,247**	**423,643,431**	**8,516,030**
	TOTAL ASSETS	**3,041,906,789**	**1,158,301,435**	**1,247,666,008**	**683,609,752**
	LIABILITIES				
	Accounts Payable	**80,146,794**	**68,349,517**	**51,218,698**	**8,248,985**
	Advances from Affiliates	**119,572,476**	**(661,563,318)**	**968,362,946**	**(187,227,152)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**490,000,000**	**490,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities	**547,945**	**0**	**547,945**	**0**
	Accrued Taxes	**18,309,444**	**995,398**	**(15,960,178)**	**33,274,224**
	Memo: Property Taxes	21,860,355	11,065,990	3,467,060	7,327,305
	Accrued Interest	**10,711,662**	**10,711,662**	**0**	**0**
	Risk Management Collateral	2,249,816	0	2,249,816	0
2350001	Customer Deposits-Active	40,472,843	40,472,843	0	0
	Utility Customer Deposits	40,472,843	40,472,843	0	0
	Deposits - Customer and Collateral	**42,722,660**	**40,472,843**	**2,249,816**	**0**

BS8216 YTD Oct 2023 11/09/2023 18:08	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Oct 2023	YTD Oct 2023	YTD Oct 2023	YTD Oct 2023
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	102,406	26,011	76,395	0
	Obligations under Operating Leases - Current	128,127	104,598	20,501	3,028
	Tax Collections Payable	1,701,501	1,701,501	0	0
	Revenue Refunds - Accrued	616,239	0	141,552	474,687
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	1,204,042	1,072,639	120,589	10,814
	Accrued Rents	1,275	1,275	0	0
	Accrued ICP	1,658,280	1,535,686	116,444	6,151
	Accrued Vacations	2,695,978	2,386,901	289,114	19,963
	Misc Employee Benefits	1,746,466	962,694	781,643	2,130
	Payroll Deductions	118,073	93,411	23,390	1,272
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	185,228	169,626	15,602	0
2530022	Customer Advance Receipts	5,812,916	5,812,916	0	0
	Customer Advance	5,812,916	5,812,916	0	0
2420511	Control Cash Disburse Account	1,809,733	1,809,733	0	0
	Control Cash Disbursement Account	1,809,733	1,809,733	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	111,171	0	111,171	0
2300002	ARO - Current	29,797	0	29,797	0
2420088	Econ. Development Fund Curr	458,018	458,018	0	0
2420512	Unclaimed Funds	7,464	7,464	0	0
2420542	Acc Cash Franchise Req	57,747	57,747	0	0
2420643	Accrued Audit Fees	34,380	13,975	13,490	6,915
2420656	Federal Mitigation Accru (NSR)	244,045	0	244,045	0
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	304,010	303,279	0	731
2530112	Other Deferred Credits-Curr	484,596	483,229	0	1,367
2530124	Contr In Aid of Constr Advance	171,697	171,697	0	0
2530177	Deferred Rev-Bonus Lease Curr	9,486	0	9,486	0
	Misc Current and Accrued Liabilities	1,913,096	1,496,094	407,989	9,013
	Current Other and Accrued Liabilities	19,462,827	17,042,475	1,896,323	524,030
	Other Current Liabilities	**19,693,360**	**17,173,084**	**1,993,219**	**527,057**
	TOTAL CURRENT LIABILITIES	**781,704,341**	**(33,860,814)**	**1,008,412,446**	**(145,176,885)**
	Long-Term Debt - Affiliated	**25,000,000**	**25,000,000**	**0**	**0**
	Long-Term Debt - Non Affiliated	**688,348,304**	**688,348,304**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**0**	**0**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*688,348,304*	*688,348,304*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	144,928	0	144,928	0
2440022	L/T Liability MTM Collateral	(64)	0	(64)	0
	Long-Term Risk Management Liabilities - MTM	144,864	0	144,864	0
	Long-Term Risk Management Liabilities	**144,864**	**0**	**144,864**	**0**
	Deferred Income Taxes	**472,263,788**	**162,338,510**	**217,311,243**	**92,614,034**
	Deferred Investment Tax Credits	**(0)**	**0**	**(0)**	**0**
	Regulatory Liabilities and Deferred Credits	**98,328,514**	**66,995,858**	**2,979,745**	**28,352,911**
	Memo - Reg Liab and Def ITC	*98,328,514*	*66,995,858*	*2,979,744*	*28,352,911*
	Asset Retirement Obligation	**18,331,030**	**198,894**	**18,132,136**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**

BS8216 YTD Oct 2023 11/09/2023 18:08	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Oct 2023	YTD Oct 2023	YTD Oct 2023	YTD Oct 2023
	Employee Benefits and Pension Obligations	**7,882,477**	**10,980,140**	**(4,673,735)**	**1,576,072**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redempt	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	569,056	344,422	224,634	0
	Obligations Under Operating Leases	624,773	391,048	233,725	0
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	112,132	112,132	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	42,535	42,535	0	0
2530101	MACSS Unidentified EDI Cash	1,129	1,129	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	1,110	0	0	1,110
2530185	O\U Accounting of ExpensesT	5,926	0	5,926	0
2530188	Long Term Assoc AP	1,062,738	0	305,637	757,101
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	1,198,054	43,664	311,563	842,827
	Total Other Deferred Credits	1,310,186	155,796	311,563	842,827
	Accumulated Provisions - Rate Refund	1,502,947	0	0	1,502,947
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**4,006,962**	**891,266**	**769,922**	**2,345,774**
	TOTAL NON-CURRENT LIABILITIES	**1,314,305,939**	**954,752,973**	**234,664,175**	**124,888,791**
	TOTAL LIABILITIES	**2,096,010,279**	**920,892,159**	**1,243,076,621**	**(20,288,094)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,301,579**	**106,025,371**	**336,070,072**	**84,206,136**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**369,144,930**	**108,979,856**	**(341,768,288)**	**601,933,362**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**945,896,509**	**237,409,276**	**4,589,387**	**703,897,846**
	Memo: Total Equity	945,896,509	237,409,276	4,589,387	703,897,846
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,041,906,789**	**1,158,301,435**	**1,247,666,008**	**683,609,752**

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Application - Section II
Filing Requirements
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KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - October, 2024

Final

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		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,276,923,610.03	51,859,227.57	(12,253,142.01)	0.00	0.00	1,316,529,695.59
101/106	CLOUD GENERATION	381,874.02	53,716.99	0.00	0.00	0.00	435,591.01
	TOTAL PRODUCTION	**1,277,305,484.05**	**51,912,944.56**	**(12,253,142.01)**	**0.00**	**0.00**	**1,316,965,286.60**
101/106	TRANSMISSION	842,600,699.05	44,442,614.07	(3,514,215.59)	0.00	0.00	883,529,097.53
101/106	CLOUD TRANSMISSION	201,394.70	85,554.82	0.00	0.00	0.00	286,949.52
101/106	DISTRIBUTION	1,249,889,192.92	64,869,968.34	(11,426,866.35)	0.00	0.00	1,303,332,294.91
101/106	CLOUD DISTRIBUTION	1,618,196.01	371,035.78	0.00	0.00	0.00	1,989,231.79
	TOTAL (ACCOUNTS 101 & 106)	**3,371,614,966.73**	**161,682,117.57**	**(27,194,223.95)**	**0.00**	**0.00**	**3,506,102,860.35**
1011001/12	CAPITAL LEASES	1,080,445.85	0.00	0.00	166,637.85	0.00	1,247,083.70
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**3,372,695,412.58**	**161,682,117.57**	**(27,194,223.95)**	**166,637.85**	**0.00**	**3,507,349,944.05**
1050001	PLANT HELD FOR FUTURE USE	801,671.21	0.00	0.00	0.00	0.00	801,671.21
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEGINNING BALANCE	159,612,262.17					
107000X	ADDITIONS		165,472,182.55				
107000X	TRANSFERS		(138,443,137.78)				
107000X	ENDING BALANCE		27,029,044.77				186,641,306.94
107000X	**CLOUD CONSTRUCTION WIP:**						
107000X	BEGINNING BALANCE	1,540,647.27					
107000X	ADDITIONS		763,867.04				
107000X	TRANSFERS		(510,307.59)				
107000X	ENDING BALANCE		253,559.45				1,794,206.72
	TOTAL ELECTRIC UTILITY PLANT	**3,534,649,993.23**	**188,964,721.79**	**(27,194,223.95)**	**166,637.85**	**0.00**	**3,696,587,128.92**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	571,711.48	0.00	(69,345.76)	0.00	0.00	502,365.72
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1210003	NONUTILITY PROPERTY-WIP						
	BEGINNING BALANCE	0.00					
	ADDITIONS		0.00				
	TRANSFERS		0.00				
	ENDING BALANCE		0.00				0.00
1210016	NONUTILITY PROPERTY-CCNC	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	655,168.37	0.00	0.00	0.00	0.00	655,168.37
	TOTAL NONUTILITY PLANT	**1,226,879.85**	**0.00**	**(69,345.76)**	**0.00**	**0.00**	**1,157,534.09**

KPSC Case No. 2025-00257
Application - Section II
Filing Requirements
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KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - October, 2024

Final

GLR7410 11/11/24 14:47

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
.	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	623,339,018.27	31,787,070.21	(9,861,105.79)	(4,810,860.41)	(4,118,311.49)	636,335,810.79
1080001/11	TRANSMISSION	284,929,166.47	19,903,177.26	(2,795,167.13)	(809,503.09)	0.00	301,227,673.51
1080001/11	DISTRIBUTION	376,851,080.91	37,354,924.46	(8,930,799.64)	(3,416,699.51)	(152,964.97)	401,705,541.25
1080013	PRODUCTION	(4,098,119.71)	0.00	0.00	0.00	4,098,119.71	0.00
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(151,934.59)	0.00	0.00	0.00	151,934.59	0.00
	RETIREMENT WORK IN PROGRESS	(13,358,319.70)	0.00	0.00	(11,206,901.38)	9,037,063.01	(15,528,158.07)
	TOTAL (108X accounts)	**1,267,510,891.66**	**89,045,171.93**	**(21,587,072.56)**	**(20,243,964.39)**	**9,015,840.85**	**1,323,740,867.49**
	NUCLEAR					0.00	
1110001	PRODUCTION	12,296,619.11	2,800,478.42	(2,392,036.22)	0.00	0.00	12,705,061.31
1110007	CLOUD IMPLEMENT COST PRODUCT	103,001.61	67,528.94	0.00	0.00	0.00	170,530.55
1110001	TRANSMISSION	4,150,582.38	1,289,282.44	(719,048.46)	0.00	0.00	4,720,816.36
1110007	CLOUD IMPLEMENT COST TRANSMIS	36,477.38	40,191.89	0.00	0.00	0.00	76,669.27
1110001	DISTRIBUTION	14,363,824.54	3,950,826.56	(2,496,066.71)	0.00	0.00	15,818,584.39
1110007	CLOUD IMPLEMENT COST DISTRIBUT	417,883.25	256,719.49	0.00	0.00	0.00	674,602.74
	TOTAL (111X accounts)	**31,368,388.27**	**8,405,027.74**	**(5,607,151.39)**	**0.00**	**0.00**	**34,166,264.62**
1011006	CAPITAL LEASES	291,805.66	0.00	0.00	0.00	101,497.36	393,303.02
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**1,299,171,085.59**	**97,450,199.67**	**(27,194,223.95)**	**(20,243,964.39)**	**9,117,338.21**	**1,358,300,435.13**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	172,262.12	5,558.15	(69,345.76)	69,987.88	0.00	178,462.39
1220002	Depr&Amrt of Nonutl Prop-Leasd	0.00	0.00	0.00	0.00	0.00	0.00
1220003	Depr&Amrt of Nonutl Prop-WIP	69,987.88	0.00	0.00	0.00	(69,987.88)	0.00
1220004	Depletion - Owned	0.00	0.00	0.00	0.00	0.00	0.00
1240027	Other Property - RWIP	35,121.36	0.00	0.00	0.00	0.00	35,121.36
1240028	Other Property - Retirement	(46,947.27)	0.00	0.00	0.00	0.00	(46,947.27)
	TOTAL NONUTILITY PLANT	**230,424.09**	**5,558.15**	**(69,345.76)**	**69,987.88**	**(69,987.88)**	**166,636.48**

KPSC Case No. 2025-00257
Application - Section II
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U.S. Department of Energy
Energy Information Administration
Form EIA-826

Monthly Electric Utility Sales and Revenue Report with State Distributions – 2024

Form Approval
OMB NO.1905-0129
(Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**

Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650.

Utility Name: Kentucky Power Company **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan___ Feb___ Mar___ Apr___ May___ Jun___ Jul___ Aug___ Sep___ Oct_X__ Nov___ Dec__ , 2024

Contact Person: Sandra Vargo **Phone number: 614-716-2671**

Email: slvargo@aep.com **Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	$ 17,879	$ 15,483	$ 14,455	$ -	$ 47,816
	b. Megwatthours	112,333	124,193	175,459	-	411,985
	c. Number of consumers	130,877	30,770	955	-	162,602
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					

Note:

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Brian J. Frantz

Digitally signed by Brian J. Frantz
DN: cn=Brian J. Frantz, c=US, o=AEP, ou=Corporate Accounting, email=bjfrantz@aep.com
Reason: I have reviewed this document
Date: 2024.12.31 10:52:00 -05'00'

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American Electric Power

INCOME STATEMENT

IS8016
YTD Nov 2024
12/09/2024 09:44

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Nov 2024	Kentucky Power Company - Distribution 110 Actual YTD Nov 2024	Kentucky Power Company - Generation 117 Actual YTD Nov 2024	Kentucky Power Company - Transmission 180 Actual YTD Nov 2024
		REVENUES				
4400001		Residential Sales-W/Space Htg	125,201,853	125,201,853	0	0
4400002		Residential Sales-W/O Space Ht	58,609,476	59,649,570	(1,040,093)	0
4400005		Residential Fuel Rev	63,598,934	63,598,934	0	0
	A	**Revenue - Residential Sales**	**247,410,263**	**248,450,356**	**(1,040,093)**	**-**
4420001		Commercial Sales	89,947,177	90,808,649	(861,472)	0
4420006		Sales to Pub Auth - Schools	14,472,790	14,472,790	0	0
4420007		Sales to Pub Auth - Ex Schools	17,881,809	17,881,809	0	0
4420013		Commercial Fuel Rev	50,581,717	50,581,717	0	0
	A	**Revenue - Commercial Sales**	**172,883,493**	**173,744,965**	**(861,472)**	**-**
	B	**Revenue - Industrial Sales - Affiliated**	**-**	**-**	**-**	**-**
4420002		Industrial Sales (Excl Mines)	66,612,195	67,885,155	(1,272,959)	0
4420004		Ind Sales-NonAffil(Incl Mines)	16,272,908	16,272,908	0	0
4420016		Industrial Fuel Rev	69,952,617	69,952,617	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**152,837,720**	**154,110,680**	**(1,272,959)**	**-**
		Revenue - Industrial Sales	**152,837,720**	**154,110,680**	**(1,272,959)**	**-**
	A	**Revenue - Gas Products Sales**	**-**	**-**	**-**	**-**
	A	**Revenue - Gas Transportation & Storage Sales**	**-**	**-**	**-**	**-**
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	**-**	**-**	**-**	**-**
4440000		Public Street/Highway Lighting	1,647,259	1,652,753	(5,494)	0
4440002		Public St & Hwy Light Fuel Rev	305,559	305,559	0	0
	A	**Revenue - Other Retail Sales**	**1,952,817**	**1,958,311**	**(5,494)**	**-**
	B	**Revenue - Other Retail Sales - Affiliated**	**-**	**-**	**-**	**-**
		Revenue - Retail Sales	**575,084,294**	**578,264,313**	**(3,180,019)**	**-**
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	74,064,721
4561033		PJM NITS Revenue - Affiliated	67,483,087	0	0	67,483,087
4561034		PJM TO Adm. Serv Rev - Aff	228,880	0	0	228,880
4561035		PJM Affiliated Trans NITS Cost	(55,623,754)	0	(55,623,754)	0
4561036		PJM Affiliated Trans TO Cost	(149,341)	0	(149,341)	0
4561059		Affil PJM Trans Enhancmnt Rev	1,432,756	0	0	1,432,756
4561060		Affil PJM Trans Enhancmnt Cost	(1,180,966)	0	(1,180,966)	0
4561062		PROVISION RTO Cost - Affi	946,238	0	946,238	0
4561063		PROVISION RTO Rev Affiliated	3,172,149	0	0	3,172,149
	B	**Revenue - Transmission-Affiliated**	**16,309,048**	**-**	**(56,007,824)**	**146,381,594**
4470150		Transm. Rev.-Dedic. Whlsl/Muni	146,720	0	(2,383,403)	2,530,123
4470206		PJM Trans loss credits-OSS	69,361	0	69,361	0
4470209		PJM transm loss charges-OSS	(178,717)	0	(178,717)	0
4561005		PJM Point to Point Trans Svc	1,967,170	0	1,967,170	0
4561006		PJM Trans Owner Admin Rev	80,056	0	0	80,056
4561007		PJM Network Integ Trans Svc	10,135,845	0	0	10,135,845
4561019		Oth Elec Rev Trans Non Affil	47,129	0	0	47,129
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	4,270	0	0	4,270
4561029		PJM NITS Revenue Whsl Cus-NAff	2,266,819	0	0	2,266,819
4561030		PJM TO Serv Rev Whls Cus-NAff	8,481	0	0	8,481
4561045		PJM Non-Aff Gen IPP Rev	9,970	0	0	9,970
4561058		NonAffil PJM Trans Enhncmt Rev	1,574,931	0	0	1,574,931
4561061		NAff PJM RTEP Rev for Whsl-FR	48,128	0	0	48,128
4561064		PROVISION RTO Rev WhslCus-NAf	106,773	0	0	106,773
4561065		PROVISION RTO Rev - NonAff	461,950	0	(1)	461,951
	A	**Revenue - Transmission-NonAffiliated**	**16,748,885**	**-**	**(525,591)**	**17,274,475**
		Revenue - Transmission	**33,057,933**	**-**	**(56,533,415)**	**163,656,069**

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INCOME STATEMENT

IS8016 YTD Nov 2024 12/09/2024 09:44			Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
		Layout: IS8016				
17A V2099-01-01		Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024
	B	**Revenue - Resale-Affiliated**	-	-	-	-
4470010		Sales for Resale-Bookout Purch	(19)	0	(19)	0
4470027		Whsal/Muni/Pb Ath Fuel Rev	2,292,536	0	2,292,536	0
4470033		Whsal/Muni/Pub Auth Base Rev	1,619,918	0	1,619,918	0
4470082		Financial Electric Realized	(6,533)	0	(6,533)	0
4470089		PJM Energy Sales Margin	206,890	0	206,890	0
4470098		PJM Oper.Reserve Rev-OSS	(39,950)	0	(39,950)	0
4470099		Capacity Cr. Net Sales	(61,258)	0	(61,258)	0
4470100		PJM FTR Revenue-OSS	210,852	0	210,852	0
4470103		PJM Energy Sales Cost	12,798,575	0	12,798,575	0
4470110		PJM TO Admin. Exp.-NonAff.	4	0	4	0
4470115		PJM Meter Corrections-OSS	41,127	0	41,127	0
4470116		PJM Meter Corrections-LSE	258,945	0	258,945	0
4470126		PJM Incremental Imp Cong-OSS	(300,381)	0	(300,381)	0
4470175		OSS Sharing Reclass - Retail	4,585,618	0	4,585,618	0
4470176		OSS Sharing Reclass-Reduction	(4,585,618)	0	(4,585,618)	0
4470215		PJM 30m Suppl Reserve CH OSS	2,731	0	2,731	0
4470220		PJM Regulation - OSS	4,636,233	0	4,636,233	0
4470221		PJM Spinning Reserve - OSS	58,499	0	58,499	0
5550080		PJM Hourly Net Purch.-FERC	(7,896,925)	0	(7,896,925)	0
	A	**Revenue - Resale-NonAffiliated**	**13,821,245**	**-**	**13,821,245**	**-**
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**13,821,245**	**-**	**13,821,245**	**-**
4470074		Sale for Resale-Aff-Trnf Price	0	0	379,742,072	0
4540001		Rent From Elect Property - Af	1,099,090	841,540	0	490,758
	B	**Revenue - Other Ele-Affilliated**	**1,099,090**	**841,540**	**379,742,072**	**490,758**
4500000		Forfeited Discounts	789,066	789,066	0	0
4510001		Misc Service Rev - Nonaffil	114,024	113,210	0	814
4540002		Rent From Elect Property-NAC	3,023,211	2,350	3,001,586	19,275
4540005		Rent from Elec Prop-Pole Attch	4,589,412	4,582,380	0	7,032
4560007		Oth Elect Rev - DSM Program	390,020	390,020	0	0
5010040		Gas Procuremnt Sales Net	(2,698,802)	0	(2,698,802)	0
		Revenue - Other Ele-NonAffilliated	**6,206,930**	**5,877,025**	**302,784**	**27,122**
		Revenue - Gas	-	-	-	-
4118002		Comp. Allow Gains Title IV SO2	14	14	0	0
4118003		Comp. Allow. Gains-Seas NOx	180,714	0	180,714	0
		Gain/(Loss) on Allowances	**180,729**	**14**	**180,714**	**-**
	A	**Revenue - Other Ele-NonAffilliated**	**6,387,659**	**5,877,039**	**483,498**	**27,122**
		Revenue - Other Opr Electric	**7,486,748**	**6,718,580**	**380,225,570**	**517,879**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
4170004		Rev from Non-Util Oper NonAfil	303,723	303,723	0	0
	D	**Revenues Non-Utility Operations - NonAffiliated**	**303,723**	**303,723**	**-**	**-**
		Revenues from Non-Utility Operations	**303,723**	**303,723**	**-**	**-**
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operatng Rental Income	1,025	1,025	0	0
4180005		Non-Opratng Rntal Inc-Depr	(6,114)	0	0	(6,114)
	D	**Non-Operating Rental Income - NonAffiliated**	**(5,089)**	**1,025**	**-**	**(6,114)**
		Non-Operating Rental Income	**(5,089)**	**1,025**	**-**	**(6,114)**

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	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024
C	**Non-Operating Misc Income -Affiliated**	-	-	-	-
4210002	Misc Non-Op Inc-NonAsc-Rents	1,652	522	817	313
4210007	Misc Non-Op Inc - NonAsc - Oth	6,877	1,085	5,792	0
D	**Non-Operating Misc Income - NonAffiliated**	**8,529**	**1,607**	**6,609**	**313**
	Non-Operating Misc Income	**8,529**	**1,607**	**6,609**	**313**
4540004	Rent From Elect Prop-ABD-Nonaf	1,674	1,674	0	0
4560015	Other Electric Revenues - ABD	572,865	461,471	0	111,394
D	**Associated Business Development Income**	**574,539**	**463,145**	**-**	**111,394**
	Revenue - Other Opr - Other	**881,702**	**769,500**	**6,609**	**105,593**
=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	**-**	**-**	**-**	**-**
=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***881,702***	***769,500***	***6,609***	***105,593***
	Revenue - Other Operating	**8,368,450**	**7,488,079**	**380,232,180**	**623,472**
4491002	Prov Rate Refund-Nonaffiliated	(120,064)	0	0	(120,064)
4491003	Prov Rate Refund - Retail	(26,617)	0	0	(26,617)
A	**Provision for Rate Refund - NonAffiliated**	**(146,681)**	**-**	**-**	**(146,681)**
4491004	Prov Rate Refund - Affiliated	(781,228)	0	0	(781,228)
B	**Provision for Rate Refund - Affiliated**	**(781,228)**	**-**	**-**	**(781,228)**
	Provision for Rate Refund	**(927,909)**	**-**	**-**	**(927,909)**
A	**Revenue - Power Sales**	**-**	**-**	**-**	**-**
	TOTAL OPERATING REVENUES	**629,404,013**	**585,752,392**	**334,339,991**	**163,351,632**
=(A)	*Memo: G/T/D Revenue*	*611,895,401*	*584,141,352*	*10,599,134*	*17,154,916*
=(B)	*Memo: Other Affiliated Revenue*	*16,626,910*	*841,540*	*323,734,248*	*146,091,123*
=(C)	*Memo: Revenue-Oth Opr-Oth Af*	-	-	-	-
=(D)	*Memo: Revenue-Oth Opr-Oth No*	*881,702*	*769,500*	*6,609*	*105,593*
	Memo: Total Operating Revenues	*629,404,013*	*585,752,392*	*334,339,991*	*163,351,632*
=(E)=(B)+(C)	*Memo: Affiliated Revenue*	***16,626,910***	***841,540***	***323,734,248***	***146,091,123***
=(F)=(D)+(A)	*Memo: Non-Affiliated Revenue*	***612,777,103***	***584,910,852***	***10,605,743***	***17,260,508***
	Memo: Total Operating Revenues	***629,404,013***	***585,752,392***	***334,339,991***	***163,351,632***
	FUEL EXPENSES				
5010000	Fuel	5,880,796	2	5,880,792	1
5010001	Fuel Consumed	72,181,819	0	72,181,819	0
5010003	Fuel - Procure Unload & Handle	3,068,725	0	3,068,725	0
5010012	Ash Sales Proceeds	17,618	0	17,618	0
5010013	Fuel Survey Activity	49,281	0	49,281	0
5010019	Fuel Oil Consumed	3,569,512	0	3,569,512	0
5010020	Nat Gas Consumed Steam	24,588,075	0	24,588,075	0
5010021	Transp Gas Consumed Steam	664,853	0	664,853	0
5010027	Gypsum handling/disposal costs	1,262,566	0	1,262,566	0
5010028	Gypsum Sales Proceeds	(1,195,602)	0	(1,195,602)	0
5010034	Gas Transp Res Fees-Steam	5,776,881	0	5,776,881	0
	Fuel Expense Total	**115,864,523**	**2**	**115,864,519**	**1**
5010005	Fuel - Deferred	3,727,036	0	3,727,036	0
	Deferred Fuel Expense	**3,727,036**	**-**	**3,727,036**	**-**
	Over Under Fuel Expense				
	Fuel for Electric Generation	**119,591,559**	**2**	**119,591,555**	**1**
	Fuel from Affiliates for Electric Generation	**-**	**-**	**-**	**-**
5090000	Allow Consum Title IV SO2	34,987	0	34,987	0
5090001	Allowance Consumption - NOx	42,857	0	42,857	0
5090009	Allow Consumpt CSAPR SO2	168	0	168	0

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IS8016 YTD Nov 2024 12/09/2024 09:44	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024
5570009	Other Pwr Exp- REC's - RETAIL	446	0	446	0
	Allowances - Consumption	**78,459**	**-**	**78,459**	**-**
5020002	Urea Expense	1,119,691	0	1,119,691	0
5020004	Lime-Related Expenses	1,955,645	0	1,955,645	0
	Emissions Control - Chemicals	**3,075,336**	**-**	**3,075,336**	**-**
	Total Fuel for Electric Generation	**122,745,353**	**2**	**122,745,349**	**1**
	Memo: NonAff Fuel/Allow/Emissions	***122,745,353***	***2***	***122,745,349***	***1***
5550004	Purchased Power-Pool Capacity	373,078	0	373,078	0
5550029	Purch Power-Assoc-Trnsfr Price	0	379,742,072	0	0
	Purchased Electricity from AEP - Affiliates	**373,078**	**379,742,072**	**373,078**	**-**
5550001	Purch Pwr-NonTrading-Nonassoc	82,097,489	0	82,097,489	0
5550023	Purch Power Capacity -NA	1,217,708	0	1,217,708	0
5550039	PJM Inadvertent Mtr Res-OSS	5,553	0	5,553	0
5550040	PJM Inadvertent Mtr Res-LSE	60,237	0	60,237	0
5550074	PJM Reactive-Charge	3,297,310	0	3,297,310	0
5550075	PJM Reactive-Credit	(1,315,303)	0	(1,315,303)	0
5550076	PJM Black Start-Charge	1,003,825	0	1,003,825	0
5550078	PJM Regulation-Charge	555,485	0	555,485	0
5550079	PJM Regulation-Credit	(13,429)	0	(13,429)	0
5550083	PJM Sync & Non Sync-Charge	447,906	0	447,906	0
5550084	PJM Sync & Non Sync-Credit	(39,345)	0	(39,345)	0
5550123	PJM OpRes-LSE-Charge	1,167,679	0	1,166,353	1,326
5550124	PJM Implicit Congestion-LSE	6,106,160	0	6,106,160	0
5550132	PJM FTR Revenue-LSE	(6,990,776)	0	(6,990,776)	0
5550137	PJM OpRes-LSE-Credit	(60,098)	0	(60,098)	0
5550153	PurchPower-Rockport Def-NonAff	152,680	0	152,680	0
5550326	PJM Transm Loss Charges - LSE	5,061,599	0	5,061,599	0
5550327	PJM Transm Loss Credits-LSE	(2,040,549)	0	(2,040,549)	0
5550328	PJM FC Penalty Credit	(2,905)	0	(2,905)	0
	Purchased Electricity for Resale - NonAffiliated	**90,711,227**	**-**	**90,709,901**	**1,326**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**
8140000	Underground Storage Expenses	1,637	0	1,637	0
	Purchased Gas for Resale - NonAffiliated	**1,637**	**-**	**1,637**	**-**
	Total Purchased Power	**91,085,943**	**379,742,072**	**91,084,617**	**1,326**
	GROSS MARGIN	**415,572,717**	**206,010,317**	**120,510,025**	**163,350,305**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	4,099,670	(9,846)	4,100,720	8,798
5020000	Steam Expenses	1,397,168	0	1,397,168	0
5050000	Electric Expenses	45,194	0	45,194	0
5060000	Misc Steam Power Expenses	5,758,725	61,913	5,688,547	8,265
5060002	Misc Steam Power Exp-Assoc	46,961	0	46,961	0
5060004	NSR Settlement Expense	10,130	0	10,130	0
5060011	BSRR O/U Recovery-Oper Costs	367	0	367	0
	Steam Generation Op Exp	**11,358,215**	**52,067**	**11,289,086**	**17,063**
	Nuclear Generation Op Exp	**-**	**-**	**-**	**-**
	Hydro Generation Op Exp	**-**	**-**	**-**	**-**
5560000	Sys Control & Load Dispatching	63,520	0	63,520	0
5570000	Other Expenses	746,970	0	746,970	0
5570007	Other Pwr Exp - Wholesale RECs	245	245	0	0
5570010	OH Auction Exp - Incremental	6	0	6	0

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	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024
5757000	PJM Admin-MAM&SC- OSS	64,003	0	64,003	0
5757001	PJM Admin-MAM&SC- Internal	1,262,174	0	1,262,174	0
	Other Generation Op Exp	**2,136,918**	**245**	**2,136,673**	**-**
5600000	Oper Supervision & Engineering	1,968,674	51,545	19,867	1,897,262
5612000	Load Dispatch-Mntr&Op TransSys	353,289	4,646	627	348,017
5614000	PJM Admin-SSC&DS-OSS	67,921	0	67,921	0
5614001	PJM Admin-SSC&DS-Internal	1,205,860	0	1,205,860	0
5614009	GreenHat Settlement	3,535	0	3,535	0
5615000	Reliability,Plng&Stds Develop	73,509	1,565	215	71,729
5618000	PJM Admin-RP&SDS-OSS	21,690	0	21,690	0
5618001	PJM Admin-RP&SDS- Internal	397,113	0	397,113	0
5620001	Station Expenses - Nonassoc	203,354	(1)	(1)	203,357
5630000	Overhead Line Expenses	26,502	(0)	(0)	26,503
5640000	Underground Line Expenses	16	0	0	16
5650002	Transmssn Elec by Others-NAC	84,333	0	84,333	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	74,064,721	0	0
5650012	PJM Trans Enhancement Charge	1,891,091	0	1,891,091	0
5650015	PJM TO Serv Exp - Aff	150,130	0	150,130	0
5650016	PJM NITS Expense - Affiliated	68,326,340	0	68,326,340	0
5650019	Affil PJM Trans Enhncement Exp	5,040,740	0	5,040,740	0
5650020	PROVISION RTO Affl Expense	(3,658,928)	0	(3,658,928)	0
5650021	PJM NITS Expense - Non-Affilia	794,851	0	794,851	0
5650023	Amort of PROVISION RTO Expense	50,243	0	50,243	0
5660000	Misc Transmission Expenses	1,081,639	118,586	2,785	960,268
5660009	PJM OATT LSE Over-Under Adjust	1,248,885	0	1,248,885	0
5660011	Misc Transm Exp - Affiliate	3,131	0	0	3,131
5670002	Rents - Associated	0	0	0	233,209
	Transmission Op Exp	**79,333,918**	**74,241,062**	**75,647,296**	**3,743,491**
5800000	Oper Supervision & Engineering	964,809	963,531	383	944
5810000	Load Dispatching	996	996	0	0
5820000	Station Expenses	357,096	356,735	(6)	368
5830000	Overhead Line Expenses	267,141	267,535	(1)	14
5840000	Underground Line Expenses	310,235	310,588	0	(352)
5850000	Street Lighting & Signal Sys E	32,348	32,351	0	0
5860000	Meter Expenses	1,274,653	1,275,939	(1)	(68)
5870000	Customer Installations Exp	176,746	176,875	0	(55)
5880000	Miscellaneous Distribution Exp	5,648,621	5,642,007	692	6,548
5890001	Rents - Nonassociated	907,347	907,347	0	0
5890002	Rents - Associated	61,799	61,799	0	0
	Distribution Op Exp	**10,001,792**	**9,995,703**	**1,066**	**7,398**
9010000	Supervision - Customer Accts	11,641	11,632	2	7
9020000	Meter Reading Expenses	33,100	33,100	0	0
9020002	Meter Reading - Regular	272,610	272,711	0	0
9020003	Meter Reading - Large Power	22,359	22,359	0	0
9030000	Cust Records & Collection Exp	284,592	281,252	(3)	3,343
9030001	Customer Orders & Inquiries	2,645,729	2,645,580	52	139
9030002	Manual Billing	8,546	8,516	16	15
9030003	Postage - Customer Bills	571,662	571,662	0	0
9030004	Cashiering	49,969	49,969	0	0
9030005	Collection Agents Fees & Exp	3,171	3,171	0	0
9030006	Credit & Oth Collection Activi	589,556	590,009	0	0

American Electric Power

IS8016 YTD Nov 2024 12/09/2024 09:44	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024
9030007	Collectors	299,597	299,597	0	0
9030009	Data Processing	34,525	34,522	5	5
9040007	Uncoll Accts - Misc Receivable	17,761	17,758	1	2
9050000	Misc Customer Accounts Exp	18,367	18,367	0	0
9070000	Supervision - Customer Service	49,557	49,564	(0)	(1)
9080000	Customer Assistance Expenses	1,159,419	1,159,457	0	0
9080009	Cust Assistance Expense - DSM	411,811	411,813	0	0
9100000	Misc Cust Svc&Informational Ex	5,398	2,507	1,495	1,396
	Customer Service and Information Op Exp	**6,489,371**	**6,483,546**	**1,567**	**4,906**
9120000	Demonstrating & Selling Exp	8,755	8,754	0	0
9120003	Demo & Selling Exp - Area Dev	50	50	0	0
9130001	Advertising Exp - Residential	80	72	7	1
	Sales Expenses	**8,885**	**8,877**	**7**	**1**
	Memo: Insurance (9240 9250)	**3,115,841**	**1,512,377**	**1,334,886**	**268,578**
9200000	Administrative & Gen Salaries	11,429,305	5,554,433	4,128,699	1,746,186
9210001	Off Supl & Exp - Nonassociated	685,825	413,016	207,124	65,744
9210003	Office Supplies & Exp - Trnsf	180	80	68	32
9210005	Cellular Phones and Pagers	13	13	0	0
9210020	EMP RECOG - Over 100 Dollars	22	14	7	0
9210021	EMP TRAVEL - Airfare	236	59	160	17
9210022	MEALS & ENT-100 Pct DEDUCTIBLE	111	46	52	14
9210023	EMP TRAVEL-MILEAGE	595	315	186	94
9210024	EMP TRAVEL-PARKING	19	9	7	3
9210025	MEALS & ENT-50 Pct DEDUCTIBLE	52	31	18	3
9210026	EMP TRAVEL-CAR RENTAL	37	22	13	2
9210027	EMP TRAVEL-TAXI AND SHUTTLE	26	12	10	4
9210028	EMP TRAVEL-HOTEL & LODGING	745	292	364	89
9210030	EMP TRAVEL-OTHER	122	92	29	1
9210031	SAFETY EQUIPMENT AND SUPPLIES	7	2	4	1
9210032	FUEL	13	9	4	0
9210033	FOOD SERVICE-CATERING	9	3	4	2
9210034	In-House Training & Seminars	106	0	0	106
9210037	OEM/TECHNICAL TRAINING	263	3	1	259
9210040	DUES-BUSINESS/PROFESSIONAL	84	35	36	13
9210041	VEHICLE-LICENSE FEES	14	5	6	3
9220000	Administrative Exp Trnsf - Cr	(287,224)	(287,224)	(0)	(0)
9220001	Admin Exp Trnsf to Cnstrction	(424,335)	(424,335)	0	0
9220002	Admin Exp Trnsf Const-Mngerial	0	(0)	0	0
9220004	Admin Exp Trnsf to ABD	(301)	(301)	0	0
9220005	Overhead Loadings	(619,572)	(416,498)	(175,013)	(28,061)
9230001	Outside Svcs Empl - Nonassoc	3,753,205	1,168,813	1,325,866	1,258,526
9230003	AEPSC Billed to Client Co	654,920	193,715	196,497	264,708
9230024	SRV-MAIL/MESSENGER-POSTAGE	1	1	0	0
9230031	SRV-OUTSIDE SERVICES (TECH)	112	37	52	23
9230034	SRV-SOFTWARE LICENSING	16,787	12,304	4,342	141
9230035	Development Project Expense	116	0	0	116
9240000	Property Insurance	1,000,028	261,093	555,727	183,208
9250000	Injuries and Damages	1,687,157	1,167,058	437,489	82,611
9250002	Emp Accdent Prvntion-Adm Exp	13	5	2	6
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	596,685	229,993	362,794	3,897
9250007	Prsnal Injries&Prop Dmage-Pub	23,989	0	23,989	0

American Electric Power

INCOME STATEMENT

IS8016
YTD Nov 2024
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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Nov 2024	Kentucky Power Company - Distribution 110 Actual YTD Nov 2024	Kentucky Power Company - Generation 117 Actual YTD Nov 2024	Kentucky Power Company - Transmission 180 Actual YTD Nov 2024
9250010	Frg Ben Loading - Workers Comp	(192,030)	(145,773)	(45,115)	(1,142)
9260000	Employee Pensions & Benefits	2,328	2,328	0	0
9260001	Edit & Print Empl Pub-Salaries	86	33	37	16
9260002	Pension & Group Ins Admin	26,339	12,101	13,830	408
9260003	Pension Plan	1,942,984	1,301,326	626,537	15,121
9260004	Group Life Insurance Premiums	119,776	78,969	40,127	679
9260005	Group Medical Ins Premiums	4,437,722	3,012,112	1,386,038	39,572
9260007	Group L-T Disability Ins Prem	370,458	334,168	35,861	429
9260009	Group Dental Insurance Prem	155,012	105,823	47,689	1,500
9260010	Training Administration Exp	1,608	780	547	282
9260012	Employee Activities	17,353	14,001	2,879	473
9260021	Postretirement Benefits - OPEB	84,706	46,130	37,405	1,171
9260027	Savings Plan Contributions	1,722,016	1,134,807	574,640	12,570
9260036	Deferred Compensation	8,845	8,845	0	0
9260037	Supplemental Pension	22,781	22,727	54	0
9260050	Frg Ben Loading - Pension	(902,393)	(766,562)	(122,826)	(13,006)
9260051	Frg Ben Loading - Grp Ins	(2,437,349)	(2,067,710)	(338,049)	(31,590)
9260052	Frg Ben Loading - Savings	(764,013)	(644,419)	(108,052)	(11,542)
9260053	Frg Ben Loading - OPEB	(97,067)	(77,722)	(17,941)	(1,405)
9260055	IntercoFringeOffset- Don't Use	(432,862)	(432,862)	0	0
9260058	Frg Ben Loading - Accrual	(23,567)	(13,768)	(9,582)	(217)
9260060	Amort-Post Retirerment Benefit	198,568	118,783	65,273	14,513
9270000	Franchise Requirements	148,971	147,629	699	644
9280000	Regulatory Commission Exp	10,791	4,580	3,362	2,849
9280001	Regulatory Commission Exp-Adm	4,347	4,185	158	3
9280002	Regulatory Commission Exp-Case	2,481,761	1,287,789	583,828	610,149
9280005	Reg Com Exp-FERC Trans Cases	20,652	157	177	20,318
9280006	State Publ Serv CommissionFees	871,763	871,763	0	0
9301000	General Advertising Expenses	25,514	11,320	7,370	6,824
9301001	Newspaper Advertising Space	25,665	11,487	7,224	6,954
9301003	TV Station Advertising Time	39,288	17,473	11,290	10,525
9301012	Public Opinion Surveys	12,539	12,538	1	1
9301015	Other Corporate Comm Exp	6,286	6,286	0	0
9302000	Misc General Expenses	262,418	114,349	96,520	51,549
9302003	Corporate & Fiscal Expenses	86,400	48,526	29,771	8,102
9302004	Research, Develop&Demonstr Exp	629	239	286	104
9310001	Rents - Real Property	16,634	16,634	0	0
9310002	Rents - Personal Property	48,292	40,122	7,423	747
	Administration & General	**26,842,612**	**12,512,348**	**10,005,996**	**4,324,346**
4111005	Accretion Expense	1,233,372	14,450	1,218,922	0
	Accretion	**1,233,372**	**14,450**	**1,218,922**	**-**
4116000	Gain From Disposition of Plant	(13,307)	(13,307)	0	0
	Loss/(Gain) on Utility Plant	**(13,307)**	**(13,307)**	**-**	**-**
9302006	Assoc Bus Dev - Materials Sold	120,525	120,525	0	0
9302007	Assoc Business Development Exp	247,493	141,757	(16)	105,759
	Associated Business Development Expenses	**368,018**	**262,283**	**(16)**	**105,759**
	Gain on Disposition of Property	**-**	**-**	**-**	**-**
4212000	Loss on Dspsition of Property	174	0	174	0
	Loss on Disposition of Property	**174**	**-**	**174**	**-**
	Loss(Gain) of Sale of Property	**174**	**-**	**174**	**-**
4265009	Factored Cust A/R Exp - Affil	3,007,526	3,007,526	0	0

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INCOME STATEMENT

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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Nov 2024	Kentucky Power Company - Distribution 110 Actual YTD Nov 2024	Kentucky Power Company - Generation 117 Actual YTD Nov 2024	Kentucky Power Company - Transmission 180 Actual YTD Nov 2024
4265010	Fact Cust A/R-Bad Debts-Affil	1,672,914	1,672,914	0	0
	Opr Exp and Factored A/R	**4,680,440**	**4,680,440**	**-**	**-**
	Water Heaters	**-**	**-**	**-**	**-**
4040007	Cloud Implement - Amort Plant	405,346	285,583	74,789	44,974
4171006	Outside Services - Other	630	630	0	0
4265004	Social & Service Club Dues	53,349	31,118	20,092	2,140
4265007	Regulatory Expenses	4,793	2,135	1,374	1,284
	Expense of Non-Utility Operation	**464,117**	**319,465**	**96,254**	**48,398**
4210009	Misc Non-Op Exp - NonAssoc	16,721	16,649	9	63
	Misc NonOp Expenses - NonAssoc	**16,721**	**16,649**	**9**	**63**
4261000	Donations	1,508,441	1,493,738	7,877	6,827
	Donation Contributions	**1,508,441**	**1,493,738**	**7,877**	**6,827**
4263001	Penalties	3,700	1,238	890	1,573
	Provision for Penalties	**3,700**	**1,238**	**890**	**1,573**
4264000	Civic and Political Activity	181,711	92,005	46,283	43,426
4264001	Non-deduct Lobbying per IRS	19,613	10,019	6,643	2,952
	Civic & Political Activities	**201,325**	**102,024**	**52,926**	**46,377**
4265002	Other Deductions - Nonassoc	369,156	327,113	29,044	13,000
	Other Deductions	**369,156**	**327,113**	**29,044**	**13,000**
	Shutdown Coal Company Expenses	**-**	**-**	**-**	**-**
	All Other Operational Expenses	**7,243,900**	**6,940,666**	**187,000**	**116,238**
	Operational Expenses	**145,003,870**	**110,497,939**	**100,487,773**	**8,319,201**
5100000	Maint Supv & Engineering	1,594,650	0	1,594,649	2
5110000	Maintenance of Structures	1,753,616	0	1,753,616	0
5120000	Maintenance of Boiler Plant	13,147,368	0	13,147,368	0
5120034	BSDR O/U Recovery - Maint Cost	(10,169)	0	(10,169)	0
5120037	KY Steam Maint O/U	(604,677)	0	(604,677)	0
5130000	Maintenance of Electric Plant	3,789,024	0	3,789,024	0
5140000	Maintenance of Misc Steam Plt	1,462,352	0	1,462,352	0
5140025	Maint MiscStmPlt Environmental	(14)	0	(14)	0
	Steam Generation Maintenance	**21,132,152**	**-**	**21,132,150**	**2**
	Nuclear Generation Maintenance	**-**	**-**	**-**	**-**
	Hydro Generation Maintenance	**-**	**-**	**-**	**-**
	Other Generation Maintenance	**-**	**-**	**-**	**-**
5680000	Maint Supv & Engineering	21,221	913	831	19,477
5690000	Maintenance of Structures	32,213	0	0	32,213
5691000	Maint of Computer Hardware	7,176	9	(15)	7,182
5692000	Maint of Computer Software	203,898	18,236	6,995	178,667
5693000	Maint of Communication Equip	6,438	331	0	6,107
5700000	Maint of Station Equipment	423,635	1,765	(0)	421,871
5710000	Maintenance of Overhead Lines	4,847,100	(5)	0	4,847,107
5720000	Maint of Underground Lines	269	0	0	269
5730000	Maint of Misc Trnsmssion Plt	2,708	50	5	2,653
	Transmission Maintenance	**5,544,658**	**21,300**	**7,815**	**5,515,547**
5900000	Maint Supv & Engineering	14,823	14,772	0	51
5910000	Maintenance of Structures	10,318	10,322	0	(4)
5920000	Maint of Station Equipment	871,290	870,260	62	969
5930000	Maintenance of Overhead Lines	34,731,981	34,738,959	(13)	62
5930001	Tree and Brush Control	392,961	392,928	0	0
5940000	Maint of Underground Lines	25,806	25,814	0	0
5950000	Maint of Lne Trnf,Rglators&Dvi	16,062	16,070	0	0

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IS8016 YTD Nov 2024 12/09/2024 09:44	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024
5960000	Maint of Strt Lghtng & Sgnal S	9,526	9,529	0	0
5970000	Maintenance of Meters	34,364	34,395	0	(0)
5980000	Maint of Misc Distribution Plt	26,234	26,233	1	1
	Distribution Maintenance	**36,133,366**	**36,139,281**	**49**	**1,078**
9350000	Maintenance of General Plant	23,140	18,304	4,836	0
9350001	Maint of Structures - Owned	859,705	851,562	5,391	2,753
9350002	Maint of Structures - Leased	12,733	6,521	548	5,664
9350012	Maint of Data Equipment	4,169	3,091	1,078	0
9350013	Maint of Cmmncation Eq-Unall	1,041,119	1,007,137	34,850	0
9350015	Maint of Office Furniture & Eq	883,727	430,659	453,068	0
9350023	Site Communications Services	98	72	26	0
9350024	Maint of DA-AMI Comm Equip	4,321	4,323	(3)	3
	Administration & General Maintenance	**2,829,014**	**2,321,670**	**499,795**	**8,420**
	All Other Maintenance Expenses	**-**	**-**	**-**	**-**
	Maintenance Expenses	**65,639,190**	**38,482,251**	**21,639,809**	**5,525,046**
	Total Operational and Maintenance Expenses	**210,643,060**	**148,980,190**	**122,127,582**	**13,844,248**
4040001	Amort. of Plant	8,442,711	4,220,303	2,885,172	1,337,236
4060001	Amort of Plt Acq Adj	35,398	0	0	35,398
	DDA Amortization	**8,478,109**	**4,220,303**	**2,885,172**	**1,372,634**
4073000	Regulatory Debits	(0)	0	(0)	0
4073014	Regulatory Debit - BSDR	353,738	0	353,738	0
	DDA Regulatory Debits	**353,737**	**-**	**353,737**	**-**
4074000	Regulatory Credits	(461,128)	(81,362)	(379,765)	0
4074025	PPA RIDER Over/Under	2,245,230	0	2,245,230	0
	DDA Regulatory Credits	**1,784,102**	**(81,362)**	**1,865,464**	**-**
	Amortization	**10,615,949**	**4,138,941**	**5,104,373**	**1,372,634**
4030001	Depreciation Exp	97,134,393	41,166,313	34,013,670	21,954,410
4030029	Over/Undr Depr Exp Var Riders	(4,136,429)	0	(4,136,429)	0
	DDA Depreciation	**92,997,963**	**41,166,313**	**29,877,241**	**21,954,410**
	DDA STP Nuclear Decommissioning	**-**	**-**	**-**	**-**
4031001	Depr - Asset Retirement Oblig	1,050,306	9,001	1,041,305	0
	DDA Asset Retirement Obligation	**1,050,306**	**9,001**	**1,041,305**	**-**
	DDA Removal Costs	**-**	**-**	**-**	**-**
	Depreciation	**94,048,269**	**41,175,314**	**30,918,546**	**21,954,410**
	Depreciation and Amortization	**104,664,218**	**45,314,255**	**36,022,919**	**23,327,044**
	Franchise Taxes	**-**	**-**	**-**	**-**
408100624	State Gross Receipts Tax	18,161	3	18,142	16
	Revenue-kWhr Taxes	**18,161**	**3**	**18,142**	**16**
4081002	FICA	3,266,891	2,211,451	1,035,094	20,346
4081003	Federal Unemployment Tax	13,396	8,359	4,946	92
4081007	State Unemployment Tax	23,635	8,558	14,995	83
4081033	Fringe Benefit Loading - FICA	(1,427,942)	(1,207,383)	(199,815)	(20,744)
4081034	Fringe Benefit Loading - FUT	(6,809)	(5,730)	(955)	(124)
4081035	Fringe Benefit Loading - SUT	(7,404)	(4,518)	(2,702)	(185)
	Payroll Taxes	**1,861,768**	**1,010,737**	**851,563**	**(532)**
408102022	State Business Occup Taxes	(28,789)	0	(28,789)	0
408102023	State Business Occup Taxes	8,974	0	8,974	0
408102024	State Business Occup Taxes	6,755,721	0	6,755,721	0
	Capacity Taxes	**6,735,906**	**-**	**6,735,906**	**-**

American Electric Power

INCOME STATEMENT

IS8016
YTD Nov 2024
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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Nov 2024	Kentucky Power Company - Distribution 110 Actual YTD Nov 2024	Kentucky Power Company - Generation 117 Actual YTD Nov 2024	Kentucky Power Company - Transmission 180 Actual YTD Nov 2024
408100521	Real Personal Property Taxes	807,087	752,106	7	54,974
408100522	Real Personal Property Taxes	1,560,190	(10)	1,560,200	0
408100523	Real Personal Property Taxes	20,436,685	10,559,347	3,285,059	6,592,278
408102922	Real-Pers Prop Tax-Cap Leases	(372,463)	(187,830)	(5,727)	(178,907)
408102923	Real-Pers Prop Tax-Cap Leases	(832)	0	(832)	0
408102924	Real-Pers Prop Tax-Cap Leases	565,430	530,959	21,249	13,222
408103623	Real Prop Tax-Cap Leases	7,431	7,431	0	0
408103624	Real Prop Tax-Cap Leases	12,474	12,474	0	0
408200523	Real Personal Property Taxes	42,106	80	41,261	765
408200524	Real Personal Property Taxes	27,710	0	27,710	0
	Property Taxes	**23,085,817**	**11,674,558**	**4,928,927**	**6,482,333**
	Regulatory Fees	**-**	**-**	**-**	**-**
408101423	Federal Excise Taxes	725	0	725	0
408101424	Federal Excise Taxes	13,915	0	13,915	0
	Production Taxes	**14,640**	**-**	**14,640**	**-**
408101923	State Sales and Use Taxes	1,530	1,530	0	0
408101924	State Sales and Use Taxes	47,805	11,499	36,305	0
	Miscellaneous Taxes	**49,335**	**13,030**	**36,305**	**-**
	Other Non-Income Taxes	**63,975**	**13,030**	**50,945**	**-**
	Taxes Other Than Income Taxes	**31,765,627**	**12,698,327**	**12,585,483**	**6,481,817**
	TOTAL OPERATING EXPENSES	**347,072,905**	**206,992,772**	**170,735,985**	**43,653,109**
	Memo: SEC Total Operating Expenses	**560,904,202**	**586,734,847**	**384,565,951**	**43,654,436**
	OPERATING INCOME	**68,499,811**	**(982,455)**	**(50,225,960)**	**119,697,196**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	928,377	269,907	407,932	250,538
	Interest & Dividend NonAffiliated	**928,377**	**269,907**	**407,932**	**250,538**
4190005	Interest Income - Assoc CBP	309	309	0	0
	Interest & Dividend Affiliated	**309**	**309**	**-**	**-**
	Total Interest & Dividend Income	**928,686**	**270,216**	**407,932**	**250,538**
	Interest & Dividend Carrying Charge	**-**	**-**	**-**	**-**
	Memo: Total Interest & Dividend Income w/ Carrying	**928,686**	**270,216**	**407,932**	**250,538**
9260042	SERP Pension - Non-Service	(3,544)	(3,524)	(20)	0
9260043	OPEB - Non-Service	2,572,878	1,023,946	1,471,550	77,382
9260062	Pension Plan - Non-Service	1,943,883	(378,789)	2,388,439	(65,768)
	Other Components of Net Periodic Pension	**4,513,217**	**641,634**	**3,859,969**	**11,614**
4191000	Allw Oth Fnds Usd Drng Cnstr	2,003,426	493,633	397,775	1,112,018
	AFUDC	**2,003,426**	**493,633**	**397,775**	**1,112,018**
	Gain on Disposition of Equity Investments	**-**	**-**	**-**	**-**
	Interest LTD FMB	**-**	**-**	**-**	**-**
4270002	Int on LTD - Install Pur Contr	(2,800,417)	(2,800,417)	0	0
	Interest LTD IPC	**(2,800,417)**	**(2,800,417)**	**-**	**-**
4300001	Interest Exp - Assoc Non-CBP	(841,257)	(841,257)	0	0
	Interest LTD Notes Payable - Affiliated	**(841,257)**	**(841,257)**	**-**	**-**
	Interest LTD Notes Payable - NonAffiliated	**-**	**-**	**-**	**-**
	Interest LTD Debentures	**-**	**-**	**-**	**-**
4270006	Int on LTD - Sen Unsec Notes	(52,324,894)	(52,324,894)	0	0
	Interest LTD Senior Unsecured	**(52,324,894)**	**(52,324,894)**	**-**	**-**

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IS8016 YTD Nov 2024 12/09/2024 09:44	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024
	Interest LTD Other - Affil	**-**	**-**	**-**	**-**
4270005	Int on LTD - Other LTD	(8,778,465)	(8,778,465)	0	0
	Interest LTD Other - NonAffil	**(8,778,465)**	**(8,778,465)**	**-**	**-**
	Interest on Long-Term Debt	**(64,745,033)**	**(64,745,033)**	**-**	**-**
4300003	Int to Assoc Co - CBP	(4,478,843)	36,593,966	(53,100,042)	12,027,232
	Interest STD - Affil	**(4,478,843)**	**36,593,966**	**(53,100,042)**	**12,027,232**
4310007	Lines Of Credit	(623,614)	(274,435)	(227,897)	(121,282)
	Interest STD - NonAffil	**(623,614)**	**(274,435)**	**(227,897)**	**(121,282)**
	Interest on Short Term Debt	**(5,102,457)**	**36,319,531**	**(53,327,939)**	**11,905,951**
4280002	Amrtz Debt Dscnt&Exp-Instl Pur	(157,479)	(157,479)	0	0
4280003	Amrtz Debt Dscnt&Exp-N/P	(10,271)	(10,271)	0	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	(542,962)	(542,962)	0	0
	Amort of Debt Disc. Prem & Exp	**(710,712)**	**(710,712)**	**-**	**-**
4281004	Amrtz Loss Rcquired Debt-Dbnt	(30,847)	(30,847)	0	0
	Amort Loss on Reacquired Debt	**(30,847)**	**(30,847)**	**-**	**-**
	Amort Gain on Reacquired Debt	**-**	**-**	**-**	**-**
	Other Interest - Fuel Recovery	**-**	**-**	**-**	**-**
4310001	Other Interest Expense	10,432,637	(74,430)	10,555,484	(48,417)
4310002	Interest on Customer Deposits	(1,854,570)	(1,854,570)	0	0
9310005	Int on Regulated Fin Leases	(11,030)	0	0	0
	Other Interest - NonAffil	**8,567,037**	**(1,929,000)**	**10,555,484**	**(48,417)**
	Other Interest Expense - Affil	**-**	**-**	**-**	**-**
	Interest Rate Hedge Unrealized (Gain)/Loss	**-**	**-**	**-**	**-**
4320000	Allw Brrwed Fnds Used Cnstr-Cr	3,545,528	885,593	630,294	2,029,641
	AFUDC-Borrowed Funds	**3,545,528**	**885,593**	**630,294**	**2,029,641**
	Total Interest Charges	**(58,476,483)**	**(30,210,468)**	**(42,142,161)**	**13,887,175**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**17,468,657**	**(29,787,440)**	**(87,702,445)**	**134,958,542**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	(4,040,726)	(9,327,935)	(17,660,463)	22,947,672
4092001	Inc Tax, Oth Inc&Ded-Federal	(256,120)	(281,202)	(23,119)	48,201
	Federal Current Income Tax	**(4,296,845)**	**(9,609,137)**	**(17,683,582)**	**22,995,874**
4101001	Prov Def I/T Util Op Inc-Fed	59,558,970	14,838,266	37,032,542	7,688,162
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(57,954,310)	(11,779,916)	(41,666,499)	(4,507,895)
	Federal Deferred Income Tax	**1,604,660**	**3,058,350**	**(4,633,957)**	**3,180,267**
	Federal Investment Tax Credits	**-**	**-**	**-**	**-**
	Federal Income Taxes	**(2,692,186)**	**(6,550,787)**	**(22,317,539)**	**26,176,141**
4091002	Income Taxes, UOI - State	709,295	(2,732,325)	(2,093,741)	5,535,362
4092002	Inc Tax, Oth Inc & Ded - State	(64,278)	(70,573)	(5,802)	12,097
	State Current Income Tax	**645,017**	**(2,802,898)**	**(2,099,544)**	**5,547,459**
4101002	Prov Def I/T Util Op Inc-State	10,280	10,280	0	0
4111002	Prv Def I/T-Cr UtilOpInc-State	(2,224,884)	0	(2,224,884)	0
	State Deferred Income Tax	**(2,214,604)**	**10,280**	**(2,224,884)**	**-**
	State Investment Tax Credits	**-**	**-**	**-**	**-**
	State Income Taxes	**(1,569,587)**	**(2,792,618)**	**(4,324,428)**	**5,547,459**
	Local Current Income Tax	**-**	**-**	**-**	**-**
	Local Deferred Income Tax	**-**	**-**	**-**	**-**
	Local Investment Tax Credits	**-**	**-**	**-**	**-**
	Local Income Taxes	**-**	**-**	**-**	**-**
	Foreign Current Income Tax	**-**	**-**	**-**	**-**

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IS8016 YTD Nov 2024 12/09/2024 09:44	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024
	Foreign Deferred Income Tax	-	-	-	-
	Foreign Investment Tax Credits	-	-	-	-
	Foreign Income Taxes	-	-	-	-
	Total Income Taxes	(4,261,773)	(9,343,406)	(26,641,967)	31,723,600
	Equity Earnings of Subs	-	-	-	-
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	21,730,430	(20,444,035)	(61,060,478)	103,234,943
	Discontinued Operations (Net of Taxes)	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-
	NET INCOME	21,730,430	(20,444,035)	(61,060,478)	103,234,943
	Minority Interest	-	-	-	-
	Preferred Stock Dividend Subs	-	-	-	-
	Earnings to Common Shareholders	21,730,430	(20,444,035)	(61,060,478)	103,234,943
	NET INCOME (LOSS) NODE before PS	21,730,430	(20,444,035)	(61,060,478)	103,234,943
	Double Check on Net Income Node after PS	-	0	-	-

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BS8216 YTD Nov 2024 12/09/2024 20:04	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024
	ASSETS				
	Cash and Cash Equivalents	(17,317)	(17,317)	0	0
	Other Cash Deposits	19,180	9,413	9,500	267
	Customers	15,445,912	12,104,494	793,705	2,547,712
	Accrued Unbilled Revenues	4,199,185	4,199,185	0	0
	Miscellaneous Accounts Receivable	15,622,742	1,442,716	56,782,129	16,712,585
	Allowances for Uncollectible Accounts	(805)	(805)	0	0
	Accounts Receivable	35,267,034	17,745,591	57,575,834	19,260,298
	Advances to Affiliates	0	0	0	0
	Fuel, Materials and Supplies	89,282,839	6,525,146	79,170,342	3,587,351
	Risk Management Contracts - Current	7,568,932	0	7,568,932	0
	Margin Deposits	6,117,933	50,826	6,067,107	0
	Unrecovered Fuel - Current	6,960,768	0	6,960,768	0
	Other Current Regulatory Assets	0	0	0	0
	Prepayments and Other Current Assets	4,064,331	3,402,538	458,729	203,064
	TOTAL CURRENT ASSETS	149,263,700	27,716,197	157,811,211	23,050,980
	Electric Production	1,282,927,351	1,309,879,217	1,318,161,469	893,467,814
	Electric Transmission	888,701,241	0	0	0
	Electric Distribution	1,174,645,104	0	0	0
	General Property, Plant and Equipment	176,392,338	83,276	(45,138)	1,119,396
	Construction Work-in-Progress	192,357,498	60,362,959	12,242,718	119,751,822
	TOTAL PROPERTY, PLANT and EQUIPMENT	3,715,023,532	1,370,325,452	1,330,359,049	1,014,339,032
	less: Accumulated Depreciation and Amortization	(1,252,751,017)	(333,136,619)	(652,503,530)	(267,110,867)
	NET PROPERTY, PLANT and EQUIPMENT	2,462,272,515	1,037,188,832	677,855,519	747,228,164
	Net Regulatory Assets	609,899,576	136,870,768	462,295,416	10,733,393
	Securitized Transition Assets and Other	0	0	0	0
	Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
	Investments in Power and Distribution Projects	0	0	0	0
	Goodwill	0	0	0	0
	Long-Term Risk Management Assets	226,098	0	226,098	0
	Employee Benefits and Pension Assets	26,909,073	14,005,005	12,116,824	787,244
	Other Non Current Assets	27,595,058	6,076,545	19,961,313	1,557,201
	TOTAL OTHER NON-CURRENT ASSETS	664,629,805	156,952,317	494,599,650	13,077,838
	TOTAL ASSETS	3,276,166,020	1,221,857,346	1,330,266,380	783,356,982
	LIABILITIES				
	Accounts Payable	118,602,575	95,116,238	61,050,775	21,750,250
	Advances from Affiliates	182,640,130	(625,434,984)	1,075,259,908	(267,184,793)
	Short-Term Debt	0	0	0	0
	Other Current Regulatory Liabilities	0	0	0	0
	Long-Term Debt Due Within One Year Non-Affiliated	150,000,000	150,000,000	0	0
	Long-Term Debt Due Within One Year - Affiliated	0	0	0	0
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	2,922,745	65,957	2,856,788	0
2440021	S/T Liability MTM Collateral	(382,616)	(65,957)	(316,659)	0
	Risk Management Liabilities - MTM	2,540,129	0	2,540,129	0
	Risk Management Liabilities	2,540,129	0	2,540,129	0
	Accrued Taxes	12,160,289	(11,232,105)	(44,564,915)	67,957,309

BS8216 YTD Nov 2024 12/09/2024 20:04	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024
	Memo: Property Taxes	28,590,658	16,093,537	4,530,724	7,966,397
	Accrued Interest	**14,356,278**	**14,356,278**	**0**	**0**
	Risk Management Collateral	496,705	0	496,705	0
	Utility Customer Deposits	37,604,564	37,604,564	0	0
	Deposits - Customer and Collateral	**38,101,269**	**37,604,564**	**496,705**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	133,375	54,411	78,965	0
	Obligations under Operating Leases - Current	239,242	104,375	63,231	71,636
	Tax Collections Payable	1,874,589	1,874,589	0	0
	Revenue Refunds - Accrued	351,572	0	129,863	221,709
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	483,399	424,152	54,515	4,732
	Accrued Rents	(5,802)	(5,802)	0	0
	Accrued ICP	1,777,338	1,642,436	127,874	7,027
	Accrued Vacations	2,402,712	2,142,218	238,051	22,443
	Misc Employee Benefits	1,253,658	1,059,672	191,526	2,460
	Payroll Deductions	93,987	83,088	9,635	1,264
	Severance / SEI	728	728	0	0
	Accrued Workers Compensation	224,664	220,868	3,796	0
2530022	Customer Advance Receipts	3,023,984	3,023,984	0	0
	Customer Advance	3,023,984	3,023,984	0	0
2420511	Control Cash Disburse Account	807,937	807,937	0	0
	Control Cash Disbursement Account	807,937	807,937	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	163,541	0	163,541	0
2300002	ARO - Current	1,442,506	0	1,442,506	0
2420088	Econ. Development Fund Curr	563,054	563,054	0	0
2420512	Unclaimed Funds	16,001	16,001	0	0
2420542	Acc Cash Franchise Req	79,086	79,086	0	0
2420643	Accrued Audit Fees	50,370	21,207	18,994	10,169
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	209,265	208,767	0	499
2530112	Other Deferred Credits-Curr	1,713	1,713	0	0
2530124	Contr In Aid of Constr Advance	509,773	509,773	0	0
	Misc Current and Accrued Liabilities	3,035,993	1,400,285	1,625,041	10,668
	Current Other and Accrued Liabilities	15,324,760	12,674,154	2,380,301	270,304
	Other Current Liabilities	**15,697,377**	**12,832,940**	**2,522,497**	**341,940**
	TOTAL CURRENT LIABILITIES	**534,098,046**	**(326,757,070)**	**1,097,305,098**	**(177,135,295)**
	Long-Term Debt - Affiliated	**0**	**0**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,061,038,808**	**1,061,038,808**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(598,531)**	**(598,531)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,060,440,277*	*1,060,440,277*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	43,213	0	43,213	0
	Long-Term Risk Management Liabilities - MTM	43,213	0	43,213	0
	Long-Term Risk Management Liabilities	**43,213**	**0**	**43,213**	**0**
	Deferred Income Taxes	**484,640,339**	**168,872,640**	**219,168,949**	**96,598,751**

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BS8216 YTD Nov 2024 12/09/2024 20:04	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024	YTD Nov 2024
	Deferred Investment Tax Credits	**0**	**0**	**0**	**0**
	Regulatory Liabilities and Deferred Credits	**117,344,222**	**87,317,986**	**(4,323,105)**	**34,349,342**
	Memo - Reg Liab and Def ITC	*117,344,222*	*87,317,986*	*(4,323,105)*	*34,349,342*
	Asset Retirement Obligation	**87,026,928**	**214,814**	**86,812,114**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**8,234,964**	**13,226,787**	**(6,781,753)**	**1,789,930**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redemp	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	785,272	623,223	162,050	0
	Obligations Under Operating Leases	1,774,766	1,311,197	178,430	285,139
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	99,203	99,203	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	27,100	27,100	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	148	0	0	148
2530175	Legal Contingencies	(141)	(141)	0	0
2530185	O\U Accounting of ExpensesT	4,870	0	4,870	0
2530188	Long Term Assoc AP	3,895,221	0	0	3,895,221
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	4,011,813	26,959	4,870	3,979,984
	Total Other Deferred Credits	4,111,017	126,163	4,870	3,979,984
	Accumulated Provisions - Rate Refund	708,720	0	0	708,720
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**7,379,775**	**2,060,582**	**345,349**	**4,973,844**
	TOTAL NON-CURRENT LIABILITIES	**1,765,109,718**	**1,332,133,085**	**295,264,767**	**137,711,866**
	TOTAL LIABILITIES	**2,299,207,764**	**1,005,376,015**	**1,392,569,866**	**(39,423,428)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**527,243,589**	**106,025,371**	**336,531,464**	**84,686,754**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**399,264,667**	**88,051,911**	**(409,122,553)**	**720,335,309**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**976,958,256**	**216,481,331**	**(62,303,486)**	**822,780,411**
	Memo: Total Equity	976,958,256	216,481,331	(62,303,486)	822,780,411
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,276,166,020**	**1,221,857,346**	**1,330,266,380**	**783,356,982**

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BS8216 YTD Nov 2023 12/12/2023 01:55	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Nov 2023	YTD Nov 2023	YTD Nov 2023	YTD Nov 2023
	ASSETS				
	Cash and Cash Equivalents	**1,684,894**	**1,684,894**	**0**	**0**
	Other Cash Deposits	**55,764**	**22,325**	**32,470**	**969**
	Customers	12,348,672	9,278,350	2,192,417	877,904
	Accrued Unbilled Revenues	7,301,956	7,301,956	0	0
	Miscellaneous Accounts Receivable	16,494,200	3,329,653	49,436,249	15,789,654
	Allowances for Uncollectible Accounts	(100,735)	(302)	(1)	(100,431)
	Accounts Receivable	**36,044,093**	**19,909,657**	**51,628,665**	**16,567,127**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**103,720,260**	**8,004,581**	**92,997,093**	**2,718,586**
	Risk Management Contracts - Current	**5,481,508**	**0**	**5,481,508**	**0**
	Margin Deposits	**974,669**	**0**	**974,669**	**0**
	Unrecovered Fuel - Current	**5,556,945**	**0**	**5,556,945**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**2,724,525**	**2,114,388**	**421,848**	**188,289**
	TOTAL CURRENT ASSETS	**156,242,659**	**31,735,845**	**157,093,198**	**19,474,971**
	Electric Production	**1,240,754,593**	**1,245,068,213**	**1,278,862,751**	**827,465,435**
	Electric Transmission	**823,651,577**	**0**	**0**	**0**
	Electric Distribution	**1,113,814,545**	**0**	**0**	**0**
	General Property, Plant and Equipment	**174,402,564**	**83,276**	**24,208**	**1,119,396**
	Construction Work-in-Progress	**173,348,078**	**60,389,921**	**25,605,596**	**87,352,561**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,525,971,356**	**1,305,541,410**	**1,304,492,556**	**915,937,391**
	less: Accumulated Depreciation and Amortization	**(1,201,134,801)**	**(319,010,982)**	**(627,117,547)**	**(255,006,272)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,324,836,556**	**986,530,428**	**677,375,009**	**660,931,119**
	Net Regulatory Assets	**547,615,502**	**128,839,609**	**411,532,961**	**7,242,932**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Assets	**22,474,713**	**11,802,755**	**10,095,855**	**576,103**
	Other Non Current Assets	**17,682,282**	**4,583,499**	**12,469,927**	**628,856**
	TOTAL OTHER NON-CURRENT ASSETS	**587,772,497**	**145,225,864**	**434,098,743**	**8,447,891**
	TOTAL ASSETS	**3,068,851,712**	**1,163,492,137**	**1,268,566,950**	**688,853,980**
	LIABILITIES				
	Accounts Payable	**85,770,773**	**70,052,618**	**56,491,846**	**11,287,664**
	Advances from Affiliates	**31,592,565**	**(758,467,417)**	**987,010,923**	**(196,950,941)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**215,000,000**	**215,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities	**7,272,419**	**0**	**7,272,419**	**0**
	Accrued Taxes	**18,250,394**	**(28,384)**	**(19,863,266)**	**38,142,043**
	Memo: Property Taxes	21,861,028	11,066,664	3,467,060	7,327,305
	Accrued Interest	**14,927,819**	**14,927,819**	**0**	**0**
	Risk Management Collateral	0	0	0	0
2350001	Customer Deposits-Active	37,657,959	37,657,959	0	0

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BS8216 YTD Nov 2023 12/12/2023 01:55	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Nov 2023	YTD Nov 2023	YTD Nov 2023	YTD Nov 2023
	Utility Customer Deposits	37,657,959	37,657,959	0	0
	Deposits - Customer and Collateral	**37,657,959**	**37,657,959**	**0**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	99,575	23,166	76,409	0
	Obligations under Operating Leases - Current	217,788	154,697	60,063	3,028
	Tax Collections Payable	1,813,500	1,813,500	0	0
	Revenue Refunds - Accrued	612,821	0	138,134	474,687
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	1,405,180	1,252,393	140,169	12,618
	Accrued Rents	1,987	1,987	0	0
	Accrued ICP	1,624,280	1,504,134	114,123	6,023
	Accrued Vacations	2,581,598	2,299,979	263,789	17,830
	Misc Employee Benefits	1,565,357	793,712	770,574	1,071
	Payroll Deductions	113,629	88,970	23,388	1,272
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	178,370	164,775	13,595	0
2530022	Customer Advance Receipts	6,247,670	6,247,670	0	0
	Customer Advance	6,247,670	6,247,670	0	0
2420511	Control Cash Disburse Account	1,542,107	1,542,107	0	0
	Control Cash Disbursement Account	1,542,107	1,542,107	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	118,665	0	118,665	0
2300002	ARO - Current	29,797	0	29,797	0
2420088	Econ. Development Fund Curr	514,273	514,273	0	0
2420512	Unclaimed Funds	7,464	7,464	0	0
2420542	Acc Cash Franchise Req	69,469	69,469	0	0
242059223	Sales Use Tax - Leased Equip	20,597	20,597	0	0
2420643	Accrued Audit Fees	60,104	24,766	23,362	11,976
2420656	Federal Mitigation Accru (NSR)	244,045	0	244,045	0
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	229,715	229,159	0	556
2530112	Other Deferred Credits-Curr	210,995	209,552	76	1,367
2530124	Contr In Aid of Constr Advance	164,940	164,940	0	0
2530177	Deferred Rev-Bonus Lease Curr	7,589	0	7,589	0
	Misc Current and Accrued Liabilities	1,678,337	1,240,905	423,534	13,898
	Current Other and Accrued Liabilities	19,364,837	16,950,132	1,887,307	527,398
	Other Current Liabilities	**19,682,200**	**17,127,995**	**2,023,779**	**530,426**
	TOTAL CURRENT LIABILITIES	**430,154,129**	**(403,729,409)**	**1,032,935,702**	**(146,990,808)**
	Long-Term Debt - Affiliated	**25,000,000**	**25,000,000**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,060,661,435**	**1,060,661,435**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(665,656)**	**(665,656)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,059,995,779*	*1,059,995,779*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	515,378	0	515,378	0
2440022	L/T Liability MTM Collateral	(33)	0	(33)	0
	Long-Term Risk Management Liabilities - MTM	515,345	0	515,345	0
	Long-Term Risk Management Liabilities	**515,345**	**0**	**515,345**	**0**

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BS8216 YTD Nov 2023 12/12/2023 01:55	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Nov 2023	YTD Nov 2023	YTD Nov 2023	YTD Nov 2023
	Deferred Income Taxes	**472,740,901**	**163,238,384**	**219,104,909**	**90,397,608**
	Deferred Investment Tax Credits	**(0)**	**0**	**(0)**	**0**
	Regulatory Liabilities and Deferred Credits	**99,209,022**	**68,591,008**	**1,616,787**	**29,001,227**
	Memo - Reg Liab and Def ITC	*99,209,022*	*68,591,008*	*1,616,786*	*29,001,227*
	Asset Retirement Obligation	**18,315,617**	**200,131**	**18,115,486**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**7,808,985**	**10,775,491**	**(4,549,001)**	**1,582,495**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redempt	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	585,999	367,859	218,141	0
	Obligations Under Operating Leases	910,742	684,919	225,823	0
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	92,751	92,751	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	41,471	41,471	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	1,036	0	0	1,036
2530175	Legal Contingencies	(356)	(356)	0	0
2530185	O\U Accounting of ExpensesT	6,814	0	6,814	0
2530188	Long Term Assoc AP	1,023,749	0	305,637	718,112
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	1,157,329	41,115	312,451	803,764
	Total Other Deferred Credits	1,250,081	133,866	312,451	803,764
	Accumulated Provisions - Rate Refund	1,611,905	0	0	1,611,905
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**4,358,727**	**1,186,644**	**756,415**	**2,415,669**
	TOTAL NON-CURRENT LIABILITIES	**1,687,944,376**	**1,328,987,438**	**235,559,939**	**123,396,999**
	TOTAL LIABILITIES	**2,118,098,506**	**925,258,029**	**1,268,495,641**	**(23,593,810)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,301,579**	**106,025,371**	**336,070,072**	**84,206,136**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**374,001,627**	**109,804,687**	**(346,286,367)**	**610,483,306**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**950,753,206**	**238,234,108**	**71,309**	**712,447,790**
	Memo: Total Equity	950,753,206	238,234,108	71,309	712,447,790
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,068,851,712**	**1,163,492,137**	**1,268,566,950**	**688,853,980**

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KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - November, 2024

Final

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		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,276,923,610.03	53,109,927.99	(12,472,247.21)	0.00	0.00	1,317,561,290.81
101/106	CLOUD GENERATION	381,874.02	60,222.03	0.00	0.00	0.00	442,096.05
	TOTAL PRODUCTION	**1,277,305,484.05**	**53,170,150.02**	**(12,472,247.21)**	**0.00**	**0.00**	**1,318,003,386.86**
101/106	TRANSMISSION	842,600,699.05	55,035,061.00	(4,167,945.92)	0.00	0.00	893,467,814.13
101/106	CLOUD TRANSMISSION	201,394.70	94,628.02	0.00	0.00	0.00	296,022.72
101/106	DISTRIBUTION	1,249,889,192.92	70,466,151.00	(12,002,650.34)	0.00	0.00	1,308,352,693.58
101/106	CLOUD DISTRIBUTION	1,618,196.01	407,189.44	0.00	0.00	0.00	2,025,385.45
	TOTAL (ACCOUNTS 101 & 106)	**3,371,614,966.73**	**179,173,179.48**	**(28,642,843.47)**	**0.00**	**0.00**	**3,522,145,302.74**
1011001/12	CAPITAL LEASES	1,080,445.85	0.00	0.00	244,584.17	0.00	1,325,030.02
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**3,372,695,412.58**	**179,173,179.48**	**(28,642,843.47)**	**244,584.17**	**0.00**	**3,523,470,332.76**
1050001	PLANT HELD FOR FUTURE USE	801,671.21	0.00	0.00	0.00	0.00	801,671.21
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEGINNING BALANCE	159,612,262.17					
107000X	ADDITIONS		188,627,703.91				
107000X	TRANSFERS		(155,882,467.79)				
107000X	ENDING BALANCE		32,745,236.12				192,357,498.29
107000X	**CLOUD CONSTRUCTION WIP:**						
107000X	BEGINNING BALANCE	1,540,647.27					
107000X	ADDITIONS		825,429.65				
107000X	TRANSFERS		(562,039.49)				
107000X	ENDING BALANCE		263,390.16				1,804,037.43
	TOTAL ELECTRIC UTILITY PLANT	**3,534,649,993.23**	**212,181,805.76**	**(28,642,843.47)**	**244,584.17**	**0.00**	**3,718,433,539.69**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	571,711.48	0.00	(69,345.76)	0.00	0.00	502,365.72
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1210003	NONUTILITY PROPERTY-WIP						
	BEGINNING BALANCE	0.00					
	ADDITIONS		0.00				
	TRANSFERS		0.00				
	ENDING BALANCE		0.00				0.00
1210016	NONUTILITY PROPERTY-CCNC	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	655,168.37	0.00	0.00	0.00	0.00	655,168.37
	TOTAL NONUTILITY PLANT	**1,226,879.85**	**0.00**	**(69,345.76)**	**0.00**	**0.00**	**1,157,534.09**

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KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - November, 2024

Final

GLR7410 12/09/24 16:28

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
.	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	623,339,018.27	35,073,344.37	(10,080,210.99)	(5,353,787.30)	(4,118,311.49)	638,860,052.86
1080001/11	TRANSMISSION	284,929,166.47	21,954,409.97	(3,448,897.46)	(809,503.09)	0.00	302,625,175.89
1080001/11	DISTRIBUTION	376,851,080.91	41,175,727.71	(9,506,583.63)	(3,566,382.15)	(152,964.97)	404,800,877.87
1080013	PRODUCTION	(4,098,119.71)	0.00	0.00	0.00	4,098,119.71	0.00
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(151,934.59)	0.00	0.00	0.00	151,934.59	0.00
	RETIREMENT WORK IN PROGRESS	(13,358,319.70)	0.00	0.00	(11,854,519.85)	9,729,672.54	(15,483,167.01)
	TOTAL (108X accounts)	**1,267,510,891.66**	**98,203,482.05**	**(23,035,692.08)**	**(21,584,192.39)**	**9,708,450.38**	**1,330,802,939.62**
	NUCLEAR					0.00	
1110001	PRODUCTION	12,296,619.11	3,054,156.83	(2,392,036.22)	0.00	0.00	12,958,739.72
1110007	CLOUD IMPLEMENT COST PRODUCTI	103,001.61	74,788.79	0.00	0.00	0.00	177,790.40
1110001	TRANSMISSION	4,150,582.38	1,409,656.76	(719,048.46)	0.00	0.00	4,841,190.68
1110007	CLOUD IMPLEMENT COST TRANSMIS	36,477.38	44,974.38	0.00	0.00	0.00	81,451.76
1110001	DISTRIBUTION	14,363,824.54	4,325,918.11	(2,496,066.71)	0.00	0.00	16,193,675.94
1110007	CLOUD IMPLEMENT COST DISTRIBUT	417,883.25	285,582.68	0.00	0.00	0.00	703,465.93
	TOTAL (111X accounts)	**31,368,388.27**	**9,195,077.55**	**(5,607,151.39)**	**0.00**	**0.00**	**34,956,314.43**
1011006	CAPITAL LEASES	291,805.66	0.00	0.00	0.00	112,190.00	403,995.66
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**1,299,171,085.59**	**107,398,559.60**	**(28,642,843.47)**	**(21,584,192.39)**	**9,820,640.38**	**1,366,163,249.71**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	172,262.12	6,113.96	(69,345.76)	69,987.88	0.00	179,018.20
1220002	Depr&Amrt of Nonutl Prop-Leasd	0.00	0.00	0.00	0.00	0.00	0.00
1220003	Depr&Amrt of Nonutl Prop-WIP	69,987.88	0.00	0.00	0.00	(69,987.88)	0.00
1220004	Depletion - Owned	0.00	0.00	0.00	0.00	0.00	0.00
1240027	Other Property - RWIP	35,121.36	0.00	0.00	0.00	0.00	35,121.36
1240028	Other Property - Retirement	(46,947.27)	0.00	0.00	0.00	0.00	(46,947.27)
	TOTAL NONUTILITY PLANT	**230,424.09**	**6,113.96**	**(69,345.76)**	**69,987.88**	**(69,987.88)**	**167,192.29**

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U.S. Department of Energy
Energy Information Administration
Form EIA-826

Monthly Electric Utility Sales and Revenue Report with State Distributions – 2024

Form Approval
OMB NO.1905-0129
(Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**

Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650.

Utility Name: Kentucky Power Company **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan___ Feb___ Mar___ Apr___ May___ Jun___ Jul___ Aug___ Sep___ Oct___ Nov_X__ Dec___ , 2024

Contact Person: Sandra Vargo **Phone number: 614-716-2671**

Email: slvargo@aep.com **Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	$ 20,677	$ 16,267	$ 13,954	$ -	$ 50,898
	b. Megwatthours	132,511	121,891	167,728	-	422,130
	c. Number of consumers	130,810	30,757	942	-	162,509
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					

Note:

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January 31st, 2025

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed December 2024 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:

1-12	Income Statement
1-3	Details of Operating Revenues
5-10	Operating Expenses – Functional Expenses
12	Detail Statement of Taxes

Balance Sheet:

13	Balance Sheet – Assets & Other Debits
13-15	Balance Sheet – Liabilities & Other Credits
14-15	Deferred Credits
15	Statement of Retained Earnings

Utility Property:

16-17	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Digitally signed by Brian J. Frantz
DN: cn=Brian J. Frantz, o=AEP, ou=Corporate Accounting, email=bjfrantz@aep.com
Reason: I have reviewed this document
Date: 2025.01.31 08:13:17 -05'00'

Brian J Frantz
Director - Corporate Accounting

American Electric Power

INCOME STATEMENT

IS8016
YTD Dec 2024
01/09/2025 08:24

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Dec 2024	Kentucky Power Company - Distribution 110 Actual YTD Dec 2024	Kentucky Power Company - Generation 117 Actual YTD Dec 2024	Kentucky Power Company - Transmission 180 Actual YTD Dec 2024
		REVENUES				
4400001		Residential Sales-W/Space Htg	143,753,023	141,327,041	2,425,982	0
4400002		Residential Sales-W/O Space Ht	64,689,696	65,817,197	(1,127,501)	0
4400005		Residential Fuel Rev	71,555,238	71,555,238	0	0
	A	**Revenue - Residential Sales**	**279,997,957**	**278,699,476**	**1,298,481**	**-**
4420001		Commercial Sales	99,930,498	99,582,186	348,312	0
4420006		Sales to Pub Auth - Schools	15,896,895	15,896,895	0	0
4420007		Sales to Pub Auth - Ex Schools	19,969,477	19,530,105	439,373	0
4420013		Commercial Fuel Rev	55,136,030	55,136,030	0	0
	A	**Revenue - Commercial Sales**	**190,932,900**	**190,145,216**	**787,685**	**-**
	B	**Revenue - Industrial Sales - Affiliated**	**-**	**-**	**-**	**-**
4420002		Industrial Sales (Excl Mines)	73,931,279	73,776,846	154,433	0
4420004		Ind Sales-NonAffil(Incl Mines)	17,604,655	17,604,655	0	0
4420016		Industrial Fuel Rev	76,108,653	76,108,653	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**167,644,587**	**167,490,154**	**154,433**	**-**
		Revenue - Industrial Sales	**167,644,587**	**167,490,154**	**154,433**	**-**
	A	**Revenue - Gas Products Sales**	**-**	**-**	**-**	**-**
	A	**Revenue - Gas Transportation & Storage Sales**	**-**	**-**	**-**	**-**
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	**-**	**-**	**-**	**-**
4440000		Public Street/Highway Lighting	1,800,763	1,806,684	(5,921)	0
4440002		Public St & Hwy Light Fuel Rev	340,051	340,051	0	0
	A	**Revenue - Other Retail Sales**	**2,140,814**	**2,146,734**	**(5,921)**	**-**
	B	**Revenue - Other Retail Sales - Affiliated**	**-**	**-**	**-**	**-**
		Revenue - Retail Sales	**640,716,258**	**638,481,580**	**2,234,678**	**-**
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	82,000,732
4561033		PJM NITS Revenue - Affiliated	73,720,415	0	0	73,720,415
4561034		PJM TO Adm. Serv Rev - Aff	251,800	0	0	251,800
4561035		PJM Affiliated Trans NITS Cost	(60,765,106)	0	(60,765,106)	0
4561036		PJM Affiliated Trans TO Cost	(165,123)	0	(165,123)	0
4561059		Affil PJM Trans Enhancmnt Rev	1,563,003	0	0	1,563,003
4561060		Affil PJM Trans Enhancmnt Cost	(1,288,327)	0	(1,288,327)	0
4561062		PROVISION RTO Cost - Affi	2,011,890	0	2,011,890	0
4561063		PROVISION RTO Rev Affiliated	3,398,524	0	0	3,398,524
	B	**Revenue - Transmission-Affiliated**	**18,727,076**	**-**	**(60,206,665)**	**160,934,473**
4470150		Transm. Rev.-Dedic. Whlsl/Muni	197,242	0	(2,566,485)	2,763,726
4470206		PJM Trans loss credits-OSS	85,815	0	85,815	0
4470209		PJM transm loss charges-OSS	(208,370)	0	(208,370)	0
4561005		PJM Point to Point Trans Svc	2,157,916	0	2,157,916	0
4561006		PJM Trans Owner Admin Rev	87,873	0	0	87,873
4561007		PJM Network Integ Trans Svc	11,058,682	0	0	11,058,682
4561019		Oth Elec Rev Trans Non Affil	52,629	0	0	52,629
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	4,387	0	0	4,387
4561029		PJM NITS Revenue Whsl Cus-NAff	2,476,343	0	0	2,476,343
4561030		PJM TO Serv Rev Whls Cus-NAff	9,288	0	0	9,288
4561045		PJM Non-Aff Gen IPP Rev	11,964	0	0	11,964
4561058		NonAffil PJM Trans Enhncmt Rev	1,718,111	0	0	1,718,111
4561061		NAff PJM RTEP Rev for Whsl-FR	52,503	0	0	52,503
4561064		PROVISION RTO Rev WhslCus-NAf	114,415	0	0	114,415
4561065		PROVISION RTO Rev - NonAff	493,868	0	(1)	493,869
	A	**Revenue - Transmission-NonAffiliated**	**18,312,666**	**-**	**(531,124)**	**18,843,791**
		Revenue - Transmission	**37,039,743**	**-**	**(60,737,790)**	**179,778,264**

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INCOME STATEMENT

IS8016
YTD Dec 2024
01/09/2025 08:24

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Dec 2024	Kentucky Power Company - Distribution 110 Actual YTD Dec 2024	Kentucky Power Company - Generation 117 Actual YTD Dec 2024	Kentucky Power Company - Transmission 180 Actual YTD Dec 2024
	B	**Revenue - Resale-Affiliated**	-	-	-	-
4470010		Sales for Resale-Bookout Purch	(19)	0	(19)	0
4470027		Whsal/Muni/Pb Ath Fuel Rev	2,595,211	0	2,595,211	0
4470033		Whsal/Muni/Pub Auth Base Rev	1,828,429	0	1,828,429	0
4470082		Financial Electric Realized	(6,872)	0	(6,872)	0
4470089		PJM Energy Sales Margin	42,938	0	42,938	0
4470098		PJM Oper.Reserve Rev-OSS	(45,078)	0	(45,078)	0
4470099		Capacity Cr. Net Sales	(72,041)	0	(72,041)	0
4470100		PJM FTR Revenue-OSS	245,574	0	245,574	0
4470103		PJM Energy Sales Cost	14,149,191	0	14,149,191	0
4470110		PJM TO Admin. Exp.-NonAff.	4	0	4	0
4470115		PJM Meter Corrections-OSS	40,593	0	40,593	0
4470116		PJM Meter Corrections-LSE	246,307	0	246,307	0
4470126		PJM Incremental Imp Cong-OSS	(316,186)	0	(316,186)	0
4470175		OSS Sharing Reclass - Retail	4,791,126	0	4,791,126	0
4470176		OSS Sharing Reclass-Reduction	(4,791,126)	0	(4,791,126)	0
4470215		PJM 30m Suppl Reserve CH OSS	2,731	0	2,731	0
4470220		PJM Regulation - OSS	5,008,683	0	5,008,683	0
4470221		PJM Spinning Reserve - OSS	68,179	0	68,179	0
5550080		PJM Hourly Net Purch.-FERC	(8,612,447)	0	(8,612,447)	0
	A	**Revenue - Resale-NonAffiliated**	**15,175,197**	**-**	**15,175,197**	**-**
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**15,175,197**	**-**	**15,175,197**	**-**
4470074		Sale for Resale-Aff-Trnf Price	0	0	419,241,181	0
4540001		Rent From Elect Property - Af	1,228,876	918,044	0	565,242
	B	**Revenue - Other Ele-Affilliated**	**1,228,876**	**918,044**	**419,241,181**	**565,242**
4500000		Forfeited Discounts	866,468	866,468	0	0
4510001		Misc Service Rev - Nonaffil	123,253	122,365	0	888
4540002		Rent From Elect Property-NAC	3,209,458	2,700	3,187,333	19,425
4540005		Rent from Elec Prop-Pole Attch	5,007,696	5,000,029	0	7,668
4560007		Oth Elect Rev - DSM Program	416,239	416,239	0	0
5010040		Gas Procuremnt Sales Net	(2,698,803)	0	(2,698,803)	0
		Revenue - Other Ele-NonAffilliated	**6,924,311**	**6,407,801**	**488,530**	**27,981**
		Revenue - Gas	-	-	-	-
4118002		Comp. Allow Gains Title IV SO2	14	14	0	0
4118003		Comp. Allow. Gains-Seas NOx	180,714	0	180,714	0
		Gain/(Loss) on Allowances	**180,729**	**14**	**180,714**	**-**
	A	**Revenue - Other Ele-NonAffilliated**	**7,105,040**	**6,407,815**	**669,244**	**27,981**
		Revenue - Other Opr Electric	**8,333,916**	**7,325,859**	**419,910,426**	**593,223**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
4170004		Rev from Non-Util Oper NonAfil	330,190	330,190	0	0
	D	**Revenues Non-Utility Operations - NonAffiliated**	**330,190**	**330,190**	**-**	**-**
		Revenues from Non-Utility Operations	**330,190**	**330,190**	**-**	**-**
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operatng Rental Income	1,025	1,025	0	0
4180005		Non-Opratng Rntal Inc-Depr	(6,670)	0	0	(6,670)
	D	**Non-Operating Rental Income - NonAffiliated**	**(5,645)**	**1,025**	**-**	**(6,670)**
		Non-Operating Rental Income	**(5,645)**	**1,025**	**-**	**(6,670)**

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INCOME STATEMENT

IS8016
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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
		YTD Dec 2024	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024
C	**Non-Operating Misc Income -Affiliated**	-	-	-	-
4210002	Misc Non-Op Inc-NonAsc-Rents	1,790	568	879	342
4210007	Misc Non-Op Inc - NonAsc - Oth	6,521	829	5,692	0
D	**Non-Operating Misc Income - NonAffiliated**	**8,311**	**1,397**	**6,571**	**342**
	Non-Operating Misc Income	**8,311**	**1,397**	**6,571**	**342**
4540004	Rent From Elect Prop-ABD-Nonaf	1,674	1,674	0	0
4560015	Other Electric Revenues - ABD	631,645	520,251	0	111,394
D	**Associated Business Development Income**	**633,319**	**521,925**	**-**	**111,394**
	Revenue - Other Opr - Other	**966,176**	**854,538**	**6,571**	**105,066**
=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	**-**	**-**	**-**	**-**
=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***966,176***	***854,538***	***6,571***	***105,066***
	Revenue - Other Operating	**9,300,092**	**8,180,397**	**419,916,997**	**698,289**
4491002	Prov Rate Refund-Nonaffiliated	(821,058)	0	0	(821,058)
4491003	Prov Rate Refund - Retail	(181,350)	0	0	(181,350)
A	**Provision for Rate Refund - NonAffiliated**	**(1,002,408)**	**-**	**-**	**(1,002,408)**
4491004	Prov Rate Refund - Affiliated	(5,444,178)	0	0	(5,444,178)
B	**Provision for Rate Refund - Affiliated**	**(5,444,178)**	**-**	**-**	**(5,444,178)**
	Provision for Rate Refund	**(6,446,586)**	**-**	**-**	**(6,446,586)**
A	**Revenue - Power Sales**	**-**	**-**	**-**	**-**
	TOTAL OPERATING REVENUES	**695,784,704**	**646,661,977**	**376,589,083**	**174,029,967**
=(A)	*Memo: G/T/D Revenue*	*680,306,754*	*644,889,395*	*17,547,995*	*17,869,364*
=(B)	*Memo: Other Affiliated Revenue*	*14,511,774*	*918,044*	*359,034,516*	*156,055,537*
=(C)	*Memo: Revenue-Oth Opr-Oth Af*	-	-	-	-
=(D)	*Memo: Revenue-Oth Opr-Oth No*	*966,176*	*854,538*	*6,571*	*105,066*
	Memo: Total Operating Revenues	*695,784,704*	*646,661,977*	*376,589,083*	*174,029,967*
=(E)=(B)+(C)	*Memo: Affiliated Revenue*	***14,511,774***	***918,044***	***359,034,516***	***156,055,537***
=(F)=(D)+(A)	*Memo: Non-Affiliated Revenue*	***681,272,929***	***645,743,933***	***17,554,567***	***17,974,430***
	Memo: Total Operating Revenues	***695,784,704***	***646,661,977***	***376,589,083***	***174,029,967***
	FUEL EXPENSES				
5010000	Fuel	6,348,840	2	6,348,836	1
5010001	Fuel Consumed	82,196,924	0	82,196,924	0
5010003	Fuel - Procure Unload & Handle	3,550,790	0	3,550,790	0
5010012	Ash Sales Proceeds	18,854	0	18,854	0
5010013	Fuel Survey Activity	49,281	0	49,281	0
5010019	Fuel Oil Consumed	3,729,331	0	3,729,331	0
5010020	Nat Gas Consumed Steam	27,765,127	0	27,765,127	0
5010021	Transp Gas Consumed Steam	624,496	0	624,496	0
5010027	Gypsum handling/disposal costs	1,390,272	0	1,390,272	0
5010028	Gypsum Sales Proceeds	(1,285,678)	0	(1,285,678)	0
5010034	Gas Transp Res Fees-Steam	6,238,159	0	6,238,159	0
	Fuel Expense Total	**130,626,397**	**2**	**130,626,393**	**1**
5010005	Fuel - Deferred	2,053,224	0	2,053,224	0
	Deferred Fuel Expense	**2,053,224**	**-**	**2,053,224**	**-**
	Over Under Fuel Expense				
	Fuel for Electric Generation	**132,679,621**	**2**	**132,679,617**	**1**
	Fuel from Affiliates for Electric Generation	**-**	**-**	**-**	**-**
5090000	Allow Consum Title IV SO2	38,185	0	38,185	0
5090001	Allowance Consumption - NOx	42,857	0	42,857	0
5090009	Allow Consumpt CSAPR SO2	183	0	183	0

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IS8016 YTD Dec 2024 01/09/2025 08:24	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024
5570009	Other Pwr Exp- REC's - RETAIL	446	0	446	0
	Allowances - Consumption	**81,671**	**-**	**81,671**	**-**
5020002	Urea Expense	1,277,795	0	1,277,795	0
5020004	Lime-Related Expenses	2,275,717	0	2,275,717	0
	Emissions Control - Chemicals	**3,553,511**	**-**	**3,553,511**	**-**
	Total Fuel for Electric Generation	**136,314,804**	**2**	**136,314,800**	**1**
	Memo: NonAff Fuel/Allow/Emissions	***136,314,804***	***2***	***136,314,800***	***1***
5550004	Purchased Power-Pool Capacity	373,078	0	373,078	0
5550029	Purch Power-Assoc-Trnsfr Price	0	419,241,181	0	0
	Purchased Electricity from AEP - Affiliates	**373,078**	**419,241,181**	**373,078**	**-**
5550001	Purch Pwr-NonTrading-Nonassoc	89,007,716	0	89,007,716	0
5550023	Purch Power Capacity -NA	1,419,257	0	1,419,257	0
5550039	PJM Inadvertent Mtr Res-OSS	4,912	0	4,912	0
5550040	PJM Inadvertent Mtr Res-LSE	56,066	0	56,066	0
5550074	PJM Reactive-Charge	3,587,471	0	3,587,471	0
5550075	PJM Reactive-Credit	(1,434,876)	0	(1,434,876)	0
5550076	PJM Black Start-Charge	1,098,815	0	1,098,815	0
5550078	PJM Regulation-Charge	598,523	0	598,523	0
5550079	PJM Regulation-Credit	(239,639)	0	(239,639)	0
5550083	PJM Sync & Non Sync-Charge	469,976	0	469,976	0
5550084	PJM Sync & Non Sync-Credit	(35,885)	0	(35,885)	0
5550123	PJM OpRes-LSE-Charge	1,290,397	0	1,289,072	1,326
5550124	PJM Implicit Congestion-LSE	6,943,743	0	6,943,743	0
5550132	PJM FTR Revenue-LSE	(7,555,126)	0	(7,555,126)	0
5550137	PJM OpRes-LSE-Credit	(64,274)	0	(64,274)	0
5550153	PurchPower-Rockport Def-NonAff	152,680	0	152,680	0
5550326	PJM Transm Loss Charges - LSE	5,651,442	0	5,651,442	0
5550327	PJM Transm Loss Credits-LSE	(2,334,575)	0	(2,334,575)	0
5550328	PJM FC Penalty Credit	(2,918)	0	(2,918)	0
	Purchased Electricity for Resale - NonAffiliated	**98,613,706**	**-**	**98,612,380**	**1,326**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**
	Purchased Gas for Resale - NonAffiliated	**-**	**-**	**-**	**-**
	Total Purchased Power	**98,986,784**	**419,241,181**	**98,985,458**	**1,326**
	GROSS MARGIN	**460,483,116**	**227,420,793**	**141,288,824**	**174,028,640**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	4,426,924	(8,672)	4,426,090	9,507
5020000	Steam Expenses	1,499,732	0	1,499,732	0
5050000	Electric Expenses	44,420	0	44,420	0
5060000	Misc Steam Power Expenses	6,203,364	81,217	6,113,075	9,072
5060002	Misc Steam Power Exp-Assoc	51,993	0	51,993	0
5060004	NSR Settlement Expense	10,130	0	10,130	0
5060011	BSRR O/U Recovery-Oper Costs	367	0	367	0
	Steam Generation Op Exp	**12,236,930**	**72,545**	**12,145,807**	**18,579**
	Nuclear Generation Op Exp	**-**	**-**	**-**	**-**
	Hydro Generation Op Exp	**-**	**-**	**-**	**-**
5560000	Sys Control & Load Dispatching	69,875	0	69,875	0
5570000	Other Expenses	798,310	0	798,310	0
5570007	Other Pwr Exp - Wholesale RECs	245	245	0	0
5570010	OH Auction Exp - Incremental	6	0	6	0
5757000	PJM Admin-MAM&SC- OSS	71,815	0	71,815	0

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IS8016 YTD Dec 2024 01/09/2025 08:24	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024
5757001	PJM Admin-MAM&SC- Internal	1,371,179	0	1,371,179	0
	Other Generation Op Exp	**2,311,429**	**245**	**2,311,184**	**-**
5600000	Oper Supervision & Engineering	2,064,772	54,394	20,948	1,989,430
5612000	Load Dispatch-Mntr&Op TransSys	386,085	4,683	632	380,770
5613000	Load Dispatch-Trans Srvc&Sched	130	0	0	130
5614000	PJM Admin-SSC&DS-OSS	77,261	0	77,261	0
5614001	PJM Admin-SSC&DS-Internal	1,316,102	0	1,316,102	0
5614009	GreenHat Settlement	3,535	0	3,535	0
5615000	Reliability,Plng&Stds Develop	78,081	1,689	232	76,160
5618000	PJM Admin-RP&SDS-OSS	24,328	0	24,328	0
5618001	PJM Admin-RP&SDS- Internal	427,882	0	427,882	0
5620001	Station Expenses - Nonassoc	203,496	(1)	(1)	203,498
5630000	Overhead Line Expenses	27,183	(0)	(0)	27,184
5640000	Underground Line Expenses	16	0	0	16
5650002	Transmssn Elec by Others-NAC	93,290	0	93,290	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	82,000,732	0	0
5650012	PJM Trans Enhancement Charge	2,061,529	0	2,061,529	0
5650015	PJM TO Serv Exp - Aff	166,047	0	166,047	0
5650016	PJM NITS Expense - Affiliated	74,649,603	0	74,649,603	0
5650019	Affil PJM Trans Enhncement Exp	5,498,989	0	5,498,989	0
5650020	PROVISION RTO Affl Expense	(4,823,430)	0	(4,823,430)	0
5650021	PJM NITS Expense - Non-Affilia	873,799	0	873,799	0
5650023	Amort of PROVISION RTO Expense	54,808	0	54,808	0
5660000	Misc Transmission Expenses	1,195,054	171,712	2,879	1,020,464
5660009	PJM OATT LSE Over-Under Adjust	1,248,885	0	1,248,885	0
5660011	Misc Transm Exp - Affiliate	3,537	0	0	3,537
5670002	Rents - Associated	0	0	0	254,409
	Transmission Op Exp	**85,630,982**	**82,233,209**	**81,697,317**	**3,955,598**
5800000	Oper Supervision & Engineering	1,192,876	1,191,050	415	1,467
5810000	Load Dispatching	1,048	1,048	0	0
5820000	Station Expenses	387,429	386,243	(5)	1,190
5830000	Overhead Line Expenses	281,491	281,933	(1)	16
5840000	Underground Line Expenses	326,743	327,096	0	(353)
5850000	Street Lighting & Signal Sys E	40,243	40,246	0	0
5860000	Meter Expenses	1,352,130	1,353,504	(1)	(68)
5870000	Customer Installations Exp	191,872	192,004	0	(48)
5880000	Miscellaneous Distribution Exp	6,285,118	6,277,011	794	8,018
5890001	Rents - Nonassociated	985,111	985,111	0	0
5890002	Rents - Associated	63,247	63,247	0	0
	Distribution Op Exp	**11,107,308**	**11,098,493**	**1,203**	**10,221**
9010000	Supervision - Customer Accts	13,540	13,531	2	7
9020000	Meter Reading Expenses	27,331	27,331	0	0
9020002	Meter Reading - Regular	296,258	296,372	0	0
9020003	Meter Reading - Large Power	23,227	23,227	0	0
9030000	Cust Records & Collection Exp	308,146	304,513	(1)	3,633
9030001	Customer Orders & Inquiries	2,844,720	2,844,503	76	186
9030002	Manual Billing	8,976	8,946	16	15
9030003	Postage - Customer Bills	623,338	623,338	0	0
9030004	Cashiering	54,708	54,708	0	0
9030005	Collection Agents Fees & Exp	3,384	3,384	0	0
9030006	Credit & Oth Collection Activi	645,399	645,882	0	0

American Electric Power

INCOME STATEMENT

IS8016
YTD Dec 2024
01/09/2025 08:24

Layout: IS8016
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9030007	Collectors	321,082	321,082	0	0
9030009	Data Processing	35,871	35,869	5	5
9040007	Uncoll Accts - Misc Receivable	20,263	20,260	1	2
9050000	Misc Customer Accounts Exp	19,916	19,916	0	0
9070000	Supervision - Customer Service	51,149	51,159	(2)	(4)
9080000	Customer Assistance Expenses	1,249,523	1,249,564	0	0
9080009	Cust Assistance Expense - DSM	437,840	437,842	0	0
9100000	Misc Cust Svc&Informational Ex	14,283	10,269	2,069	1,945
9100001	Misc Cust Svc & Info Exp - RCS	98	52	0	46
	Customer Service and Information Op Exp	**6,999,054**	**6,991,752**	**2,166**	**5,836**
9120000	Demonstrating & Selling Exp	10,967	10,966	0	0
9120003	Demo & Selling Exp - Area Dev	64	64	0	0
9130001	Advertising Exp - Residential	80	72	7	1
	Sales Expenses	**11,111**	**11,102**	**8**	**1**
	Memo: Insurance (9240 9250)	**3,357,241**	**1,642,358**	**1,420,913**	**293,970**
9200000	Administrative & Gen Salaries	12,245,256	5,991,368	4,387,549	1,866,353
9210001	Off Supl & Exp - Nonassociated	513,470	305,078	141,216	67,247
9210003	Office Supplies & Exp - Trnsf	194	87	73	34
9210005	Cellular Phones and Pagers	14	13	0	0
9210020	EMP RECOG - Over 100 Dollars	22	14	7	0
9210021	EMP TRAVEL - Airfare	252	70	165	18
9210022	MEALS & ENT-100 Pct DEDUCTIBLE	123	50	57	16
9210023	EMP TRAVEL-MILEAGE	662	353	211	98
9210024	EMP TRAVEL-PARKING	41	14	24	3
9210025	MEALS & ENT-50 Pct DEDUCTIBLE	63	35	23	4
9210026	EMP TRAVEL-CAR RENTAL	77	25	49	4
9210027	EMP TRAVEL-TAXI AND SHUTTLE	26	12	10	4
9210028	EMP TRAVEL-HOTEL & LODGING	864	308	463	93
9210030	EMP TRAVEL-OTHER	165	93	71	1
9210031	SAFETY EQUIPMENT AND SUPPLIES	7	2	4	1
9210032	FUEL	15	10	5	1
9210033	FOOD SERVICE-CATERING	9	3	4	2
9210034	In-House Training & Seminars	106	0	0	106
9210037	OEM/TECHNICAL TRAINING	263	3	1	259
9210040	DUES-BUSINESS/PROFESSIONAL	84	35	36	13
9210041	VEHICLE-LICENSE FEES	20	7	8	4
9220000	Administrative Exp Trnsf - Cr	(698,311)	(698,311)	(0)	(0)
9220001	Admin Exp Trnsf to Cnstrction	(457,097)	(457,097)	0	0
9220002	Admin Exp Trnsf Const-Mngerial	0	(0)	0	0
9220004	Admin Exp Trnsf to ABD	(441)	(441)	0	0
9220005	Overhead Loadings	(669,026)	(453,709)	(185,322)	(29,994)
9230001	Outside Svcs Empl - Nonassoc	5,193,849	1,629,683	1,848,979	1,715,188
9230003	AEPSC Billed to Client Co	451,942	56,336	297,332	98,274
9230023	SRV-TEMPORARY AGENCY LABOR	0	0	0	0
9230024	SRV-MAIL/MESSENGER-POSTAGE	1	1	0	0
9230031	SRV-OUTSIDE SERVICES (TECH)	169	56	78	35
9230034	SRV-SOFTWARE LICENSING	16,773	12,294	4,338	141
9230035	Development Project Expense	116	0	0	116
9230064	Def AEPSC Pension Settlement	1,066,283	416,047	182,946	467,290
9240000	Property Insurance	1,092,472	284,626	608,200	199,646
9250000	Injuries and Damages	1,844,893	1,277,507	476,030	91,356

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IS8016 YTD Dec 2024 01/09/2025 08:24	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024
9250002	Emp Accdent Prvntion-Adm Exp	43	15	13	14
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	595,472	233,110	358,108	4,255
9250007	Prsnal Injries&Prop Dmage-Pub	26,971	0	26,971	0
9250010	Frg Ben Loading - Workers Comp	(202,610)	(152,900)	(48,409)	(1,301)
9260000	Employee Pensions & Benefits	2,513	2,513	0	0
9260001	Edit & Print Empl Pub-Salaries	86	33	37	16
9260002	Pension & Group Ins Admin	30,328	13,929	15,929	470
9260003	Pension Plan	2,103,528	1,407,417	679,621	16,491
9260004	Group Life Insurance Premiums	130,761	86,240	43,780	740
9260005	Group Medical Ins Premiums	5,245,454	3,490,191	1,712,013	43,249
9260007	Group L-T Disability Ins Prem	406,195	354,833	50,894	468
9260009	Group Dental Insurance Prem	168,427	114,847	51,943	1,637
9260010	Training Administration Exp	2,056	1,083	688	286
9260012	Employee Activities	17,432	14,104	2,817	511
9260021	Postretirement Benefits - OPEB	92,407	50,324	40,806	1,277
9260027	Savings Plan Contributions	1,857,811	1,224,207	620,017	13,587
9260036	Deferred Compensation	3,696	3,696	0	0
9260037	Supplemental Pension	24,852	24,793	59	0
9260050	Frg Ben Loading - Pension	(979,679)	(832,864)	(132,837)	(13,978)
9260051	Frg Ben Loading - Grp Ins	(2,638,907)	(2,241,360)	(363,724)	(33,823)
9260052	Frg Ben Loading - Savings	(820,554)	(690,694)	(117,584)	(12,276)
9260053	Frg Ben Loading - OPEB	(106,564)	(85,836)	(19,221)	(1,508)
9260055	IntercoFringeOffset- Don't Use	(463,333)	(463,333)	0	0
9260058	Frg Ben Loading - Accrual	(67,287)	(48,229)	(18,991)	(67)
9260060	Amort-Post Retirerment Benefit	216,619	129,581	71,206	15,832
9270000	Franchise Requirements	162,329	160,987	699	644
9280000	Regulatory Commission Exp	13,685	5,833	4,211	3,640
9280001	Regulatory Commission Exp-Adm	4,347	4,185	158	3
9280002	Regulatory Commission Exp-Case	3,002,008	1,372,084	974,795	655,133
9280005	Reg Com Exp-FERC Trans Cases	21,582	127	145	21,311
9280006	State Publ Serv CommissionFees	951,195	951,195	0	0
9301000	General Advertising Expenses	31,514	13,937	9,103	8,473
9301001	Newspaper Advertising Space	25,665	11,487	7,224	6,954
9301003	TV Station Advertising Time	39,498	17,564	11,351	10,583
9301012	Public Opinion Surveys	16,866	16,864	1	1
9301015	Other Corporate Comm Exp	6,318	6,318	0	0
9302000	Misc General Expenses	293,396	127,504	107,375	58,518
9302003	Corporate & Fiscal Expenses	88,456	49,775	30,501	8,180
9302004	Research, Develop&Demonstr Exp	626	239	286	101
9310001	Rents - Real Property	17,434	17,434	0	0
9310002	Rents - Personal Property	52,565	43,742	8,030	794
	Administration & General	**30,976,554**	**13,799,544**	**11,890,571**	**5,286,529**
4111005	Accretion Expense	1,425,167	15,941	1,409,226	0
	Accretion	**1,425,167**	**15,941**	**1,409,226**	**-**
4116000	Gain From Disposition of Plant	(14,517)	(14,517)	0	0
	Loss/(Gain) on Utility Plant	**(14,517)**	**(14,517)**	**-**	**-**
9302006	Assoc Bus Dev - Materials Sold	120,525	120,525	0	0
9302007	Assoc Business Development Exp	257,582	149,118	(42)	108,514
	Associated Business Development Expenses	**378,107**	**269,644**	**(42)**	**108,514**
	Gain on Disposition of Property	**-**	**-**	**-**	**-**
4212000	Loss on Dspsition of Property	174	0	174	0

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IS8016 YTD Dec 2024 01/09/2025 08:24	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024
	Loss on Disposition of Property	**174**	**-**	**174**	**-**
	Loss(Gain) of Sale of Property	**174**	**-**	**174**	**-**
4265009	Factored Cust A/R Exp - Affil	3,247,182	3,247,182	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	1,740,537	1,740,537	0	0
	Opr Exp and Factored A/R	**4,987,719**	**4,987,719**	**-**	**-**
	Water Heaters	**-**	**-**	**-**	**-**
4040007	Cloud Implement - Amort Plant	447,114	315,048	82,157	49,908
4171006	Outside Services - Other	630	630	0	0
4171009	Office Supplies & Expense	15	0	15	0
4265004	Social & Service Club Dues	69,047	45,532	20,749	2,766
4265007	Regulatory Expenses	5,233	2,327	1,501	1,405
	Expense of Non-Utility Operation	**522,039**	**363,537**	**104,423**	**54,079**
4210009	Misc Non-Op Exp - NonAssoc	16,757	16,663	19	75
	Misc NonOp Expenses - NonAssoc	**16,757**	**16,663**	**19**	**75**
4261000	Donations	1,649,345	1,632,955	8,663	7,728
	Donation Contributions	**1,649,345**	**1,632,955**	**8,663**	**7,728**
4263001	Penalties	5,221	1,741	1,591	1,890
4263003	Penalties - Quality of Service	(11,745)	0	0	(11,745)
	Provision for Penalties	**(6,524)**	**1,741**	**1,591**	**(9,855)**
4264000	Civic and Political Activity	204,439	103,969	51,793	48,682
4264001	Non-deduct Lobbying per IRS	29,613	20,019	6,643	2,952
	Civic & Political Activities	**234,052**	**123,988**	**58,436**	**51,633**
4265002	Other Deductions - Nonassoc	380,535	335,564	31,021	13,950
	Other Deductions	**380,535**	**335,564**	**31,021**	**13,950**
	Shutdown Coal Company Expenses	**-**	**-**	**-**	**-**
	All Other Operational Expenses	**7,783,924**	**7,462,166**	**204,153**	**117,610**
	Operational Expenses	**158,846,223**	**121,940,124**	**109,661,766**	**9,502,889**
5100000	Maint Supv & Engineering	1,677,430	0	1,677,428	2
5110000	Maintenance of Structures	1,794,464	0	1,794,464	0
5120000	Maintenance of Boiler Plant	14,154,921	0	14,154,921	0
5120034	BSDR O/U Recovery - Maint Cost	(10,495)	0	(10,495)	0
5120037	KY Steam Maint O/U	(662,948)	0	(662,948)	0
5130000	Maintenance of Electric Plant	3,949,152	0	3,949,152	0
5140000	Maintenance of Misc Steam Plt	1,535,485	0	1,535,485	0
5140025	Maint MiscStmPlt Environmental	(14)	0	(14)	0
	Steam Generation Maintenance	**22,437,996**	**-**	**22,437,994**	**2**
	Nuclear Generation Maintenance	**-**	**-**	**-**	**-**
	Hydro Generation Maintenance	**-**	**-**	**-**	**-**
	Other Generation Maintenance	**-**	**-**	**-**	**-**
5680000	Maint Supv & Engineering	22,224	913	916	20,395
5690000	Maintenance of Structures	32,286	0	0	32,286
5691000	Maint of Computer Hardware	7,901	8	(16)	7,909
5692000	Maint of Computer Software	223,926	20,630	7,626	195,670
5693000	Maint of Communication Equip	7,739	437	0	7,301
5700000	Maint of Station Equipment	461,398	1,764	1	459,634
5710000	Maintenance of Overhead Lines	5,005,474	(5)	0	5,005,482
5720000	Maint of Underground Lines	316	0	0	316
5730000	Maint of Misc Trnsmssion Plt	2,918	50	5	2,863
	Transmission Maintenance	**5,764,182**	**23,797**	**8,532**	**5,731,857**
5900000	Maint Supv & Engineering	15,594	15,499	0	95

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INCOME STATEMENT

IS8016
YTD Dec 2024
01/09/2025 08:24

Layout: IS8016

17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Dec 2024	Kentucky Power Company - Distribution 110 Actual YTD Dec 2024	Kentucky Power Company - Generation 117 Actual YTD Dec 2024	Kentucky Power Company - Transmission 180 Actual YTD Dec 2024
5910000	Maintenance of Structures	10,318	10,322	0	(3)
5920000	Maint of Station Equipment	888,071	886,931	61	1,078
5930000	Maintenance of Overhead Lines	30,843,971	31,052,382	(8)	(200,999)
5930001	Tree and Brush Control	430,122	430,110	0	0
5940000	Maint of Underground Lines	24,167	24,176	0	0
5950000	Maint of Lne Trnf,Rglators&Dvi	16,726	16,734	0	0
5960000	Maint of Strt Lghtng & Sgnal S	9,847	9,850	0	0
5970000	Maintenance of Meters	37,610	37,643	0	(0)
5980000	Maint of Misc Distribution Plt	27,045	27,042	1	3
	Distribution Maintenance	**32,303,471**	**32,510,690**	**54**	**(199,826)**
9350000	Maintenance of General Plant	25,138	20,301	4,836	0
9350001	Maint of Structures - Owned	1,050,861	1,042,448	5,603	2,809
9350002	Maint of Structures - Leased	14,106	6,707	652	6,747
9350012	Maint of Data Equipment	4,542	3,372	1,170	0
9350013	Maint of Cmmncation Eq-Unall	1,117,280	1,081,863	36,341	0
9350015	Maint of Office Furniture & Eq	939,686	479,475	460,211	0
9350023	Site Communications Services	98	72	26	0
9350024	Maint of DA-AMI Comm Equip	5,110	5,081	8	24
	Administration & General Maintenance	**3,156,820**	**2,639,320**	**508,847**	**9,580**
	All Other Maintenance Expenses	**-**	**-**	**-**	**-**
	Maintenance Expenses	**63,662,469**	**35,173,806**	**22,955,427**	**5,541,612**
	Total Operational and Maintenance Expenses	**222,508,692**	**157,113,930**	**132,617,194**	**15,044,501**
4040001	Amort. of Plant	9,151,103	4,585,204	3,114,840	1,451,059
4060001	Amort of Plt Acq Adj	38,616	0	0	38,616
	DDA Amortization	**9,189,719**	**4,585,204**	**3,114,840**	**1,489,675**
4073000	Regulatory Debits	(0)	0	(0)	0
4073014	Regulatory Debit - BSDR	371,740	0	371,740	0
	DDA Regulatory Debits	**371,740**	**-**	**371,740**	**-**
4074000	Regulatory Credits	(122,044)	(122,044)	(1)	0
4074025	PPA RIDER Over/Under	2,754,126	0	2,754,126	0
	DDA Regulatory Credits	**2,632,082**	**(122,044)**	**2,754,126**	**-**
	Amortization	**12,193,540**	**4,463,160**	**6,240,706**	**1,489,675**
4030001	Depreciation Exp	106,106,315	45,002,356	37,051,597	24,052,363
4030029	Over/Undr Depr Exp Var Riders	(3,418,128)	0	(3,418,128)	0
	DDA Depreciation	**102,688,187**	**45,002,356**	**33,633,469**	**24,052,363**
	DDA STP Nuclear Decommissioning	**-**	**-**	**-**	**-**
4031001	Depr - Asset Retirement Oblig	1,209,506	9,857	1,199,650	0
	DDA Asset Retirement Obligation	**1,209,506**	**9,857**	**1,199,650**	**-**
	DDA Removal Costs	**-**	**-**	**-**	**-**
	Depreciation	**103,897,694**	**45,012,213**	**34,833,118**	**24,052,363**
	Depreciation and Amortization	**116,091,234**	**49,475,373**	**41,073,824**	**25,542,037**
	Franchise Taxes	**-**	**-**	**-**	**-**
408100624	State Gross Receipts Tax	19,811	3	19,792	16
	Revenue-kWhr Taxes	**19,811**	**3**	**19,792**	**16**
4081002	FICA	3,514,556	2,373,680	1,118,698	22,179
4081003	Federal Unemployment Tax	18,004	12,278	5,588	137
4081007	State Unemployment Tax	26,280	10,570	15,605	106
4081033	Fringe Benefit Loading - FICA	(1,533,461)	(1,293,856)	(217,532)	(22,073)
4081034	Fringe Benefit Loading - FUT	(7,401)	(6,232)	(1,035)	(133)

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IS8016 YTD Dec 2024 01/09/2025 08:24	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024
4081035	Fringe Benefit Loading - SUT	(8,044)	(4,919)	(2,934)	(191)
	Payroll Taxes	**2,009,934**	**1,091,520**	**918,390**	**24**
408102022	State Business Occup Taxes	(28,789)	0	(28,789)	0
408102023	State Business Occup Taxes	8,974	0	8,974	0
408102024	State Business Occup Taxes	7,369,858	0	7,369,858	0
	Capacity Taxes	**7,350,043**	**-**	**7,350,043**	**-**
408100521	Real Personal Property Taxes	807,087	752,106	7	54,974
408100522	Real Personal Property Taxes	245,190	(698,866)	1,426,527	(482,471)
408100523	Real Personal Property Taxes	15,777,940	7,937,369	3,082,524	4,758,046
408102922	Real-Pers Prop Tax-Cap Leases	(372,463)	(187,830)	(5,727)	(178,907)
408102923	Real-Pers Prop Tax-Cap Leases	(832)	0	(832)	0
408102924	Real-Pers Prop Tax-Cap Leases	436,837	409,493	17,147	10,197
408103623	Real Prop Tax-Cap Leases	7,431	7,431	0	0
408103624	Real Prop Tax-Cap Leases	14,059	14,059	0	0
408200523	Real Personal Property Taxes	42,106	80	41,261	765
408200524	Real Personal Property Taxes	33,252	0	33,252	0
	Property Taxes	**16,990,607**	**8,233,843**	**4,594,159**	**4,162,605**
	Regulatory Fees	**-**	**-**	**-**	**-**
408101423	Federal Excise Taxes	725	0	725	0
408101424	Federal Excise Taxes	13,915	0	13,915	0
	Production Taxes	**14,640**	**-**	**14,640**	**-**
408101923	State Sales and Use Taxes	1,530	1,530	0	0
408101924	State Sales and Use Taxes	52,499	12,895	39,604	0
	Miscellaneous Taxes	**54,029**	**14,425**	**39,604**	**-**
	Other Non-Income Taxes	**68,669**	**14,425**	**54,244**	**-**
	Taxes Other Than Income Taxes	**26,439,063**	**9,339,791**	**12,936,627**	**4,162,645**
	TOTAL OPERATING EXPENSES	**365,038,989**	**215,929,094**	**186,627,645**	**44,749,183**
	Memo: SEC Total Operating Expenses	**600,340,577**	**635,170,278**	**421,927,903**	**44,750,510**
	OPERATING INCOME	**95,444,127**	**11,491,699**	**(45,338,821)**	**129,279,457**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	1,002,215	329,462	422,048	250,705
	Interest & Dividend NonAffiliated	**1,002,215**	**329,462**	**422,048**	**250,705**
4190005	Interest Income - Assoc CBP	309	309	0	0
	Interest & Dividend Affiliated	**309**	**309**	**-**	**-**
	Total Interest & Dividend Income	**1,002,524**	**329,770**	**422,048**	**250,705**
	Interest & Dividend Carrying Charge	**-**	**-**	**-**	**-**
	Memo: Total Interest & Dividend Income w/ Carrying	**1,002,524**	**329,770**	**422,048**	**250,705**
9260042	SERP Pension - Non-Service	(3,866)	(3,844)	(23)	0
9260043	OPEB - Non-Service	2,817,570	1,124,327	1,608,826	84,417
9260062	Pension Plan - Non-Service	3,973,272	1,057,966	2,987,836	(72,530)
9260064	Def AEPSC Pension Settlement	(1,688,800)	(1,361,372)	(327,428)	0
	Other Components of Net Periodic Pension	**5,098,176**	**817,077**	**4,269,212**	**11,887**
4191000	Allw Oth Fnds Usd Drng Cnstr	2,033,764	501,119	397,790	1,134,855
	AFUDC	**2,033,764**	**501,119**	**397,790**	**1,134,855**
	Gain on Disposition of Equity Investments	**-**	**-**	**-**	**-**
	Interest LTD FMB	**-**	**-**	**-**	**-**
4270002	Int on LTD - Install Pur Contr	(3,055,000)	(3,055,000)	0	0

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INCOME STATEMENT

IS8016
YTD Dec 2024
01/09/2025 08:24

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Dec 2024	Kentucky Power Company - Distribution 110 Actual YTD Dec 2024	Kentucky Power Company - Generation 117 Actual YTD Dec 2024	Kentucky Power Company - Transmission 180 Actual YTD Dec 2024
	Interest LTD IPC	**(3,055,000)**	**(3,055,000)**	**-**	**-**
4300001	Interest Exp - Assoc Non-CBP	(841,257)	(841,257)	0	0
	Interest LTD Notes Payable - Affiliated	**(841,257)**	**(841,257)**	**-**	**-**
	Interest LTD Notes Payable - NonAffiliated	**-**	**-**	**-**	**-**
	Interest LTD Debentures	**-**	**-**	**-**	**-**
4270006	Int on LTD - Sen Unsec Notes	(56,952,749)	(56,952,749)	0	0
	Interest LTD Senior Unsecured	**(56,952,749)**	**(56,952,749)**	**-**	**-**
	Interest LTD Other - Affil	**-**	**-**	**-**	**-**
4270005	Int on LTD - Other LTD	(9,496,384)	(9,496,384)	0	0
	Interest LTD Other - NonAffil	**(9,496,384)**	**(9,496,384)**	**-**	**-**
	Interest on Long-Term Debt	**(70,345,390)**	**(70,345,390)**	**-**	**-**
4300003	Int to Assoc Co - CBP	(5,344,860)	39,190,988	(57,688,648)	13,152,800
	Interest STD - Affil	**(5,344,860)**	**39,190,988**	**(57,688,648)**	**13,152,800**
4310007	Lines Of Credit	(680,229)	(294,602)	(251,633)	(133,995)
	Interest STD - NonAffil	**(680,229)**	**(294,602)**	**(251,633)**	**(133,995)**
	Interest on Short Term Debt	**(6,025,089)**	**38,896,386**	**(57,940,280)**	**13,018,805**
4280002	Amrtz Debt Dscnt&Exp-Instl Pur	(171,861)	(171,861)	0	0
4280003	Amrtz Debt Dscnt&Exp-N/P	(10,905)	(10,905)	0	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	(590,641)	(590,641)	0	0
	Amort of Debt Disc. Prem & Exp	**(773,406)**	**(773,406)**	**-**	**-**
4281004	Amrtz Loss Rcquired Debt-Dbnt	(33,651)	(33,651)	0	0
	Amort Loss on Reacquired Debt	**(33,651)**	**(33,651)**	**-**	**-**
	Amort Gain on Reacquired Debt	**-**	**-**	**-**	**-**
	Other Interest - Fuel Recovery	**-**	**-**	**-**	**-**
4310001	Other Interest Expense	11,557,782	(72,007)	11,676,606	(46,818)
4310002	Interest on Customer Deposits	(2,025,950)	(2,025,950)	0	0
9310005	Int on Regulated Fin Leases	(11,791)	0	0	0
	Other Interest - NonAffil	**9,520,040**	**(2,097,957)**	**11,676,606**	**(46,818)**
	Other Interest Expense - Affil	**-**	**-**	**-**	**-**
	Interest Rate Hedge Unrealized (Gain)/Loss	**-**	**-**	**-**	**-**
4320000	Allw Brrwed Fnds Used Cnstr-Cr	3,921,790	977,966	652,702	2,291,122
	AFUDC-Borrowed Funds	**3,921,790**	**977,966**	**652,702**	**2,291,122**
	Total Interest Charges	**(63,735,705)**	**(33,376,051)**	**(45,610,972)**	**15,263,109**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**39,842,885**	**(20,236,386)**	**(85,860,743)**	**145,940,013**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	(890,212)	(9,383,331)	(18,459,743)	26,952,861
4092001	Inc Tax, Oth Inc&Ded-Federal	(278,916)	(297,899)	(28,850)	47,833
	Federal Current Income Tax	**(1,169,129)**	**(9,681,230)**	**(18,488,592)**	**27,000,693**
4101001	Prov Def I/T Util Op Inc-Fed	70,158,014	19,040,892	42,455,553	8,661,569
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(64,972,797)	(13,182,278)	(46,058,777)	(5,731,742)
	Federal Deferred Income Tax	**5,185,218**	**5,858,613**	**(3,603,224)**	**2,929,828**
	Federal Investment Tax Credits	**-**	**-**	**-**	**-**
	Federal Income Taxes	**4,016,089**	**(3,822,616)**	**(22,091,816)**	**29,930,521**
4091002	Income Taxes, UOI - State	338,204	126,068	(861,840)	1,073,976
4092002	Inc Tax, Oth Inc & Ded - State	(70,099)	(74,819)	(7,295)	12,015
	State Current Income Tax	**268,105**	**51,249**	**(869,135)**	**1,085,991**
4101002	Prov Def I/T Util Op Inc-State	2,427,570	10,280	2,417,290	0
4111002	Prv Def I/T-Cr UtilOpInc-State	(3,730,599)	(1,460,978)	(2,269,621)	0
	State Deferred Income Tax	**(1,303,030)**	**(1,450,698)**	**147,669**	**-**
	State Investment Tax Credits	**-**	**-**	**-**	**-**

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American Electric Power

INCOME STATEMENT

IS8016
YTD Dec 2024
01/09/2025 08:24

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

	Kentucky Power Int Consol IS8016 Actual YTD Dec 2024	Kentucky Power Company - Distribution 110 Actual YTD Dec 2024	Kentucky Power Company - Generation 117 Actual YTD Dec 2024	Kentucky Power Company - Transmission 180 Actual YTD Dec 2024
State Income Taxes	(1,034,925)	(1,399,449)	(721,467)	1,085,991
Local Current Income Tax	-	-	-	-
Local Deferred Income Tax	-	-	-	-
Local Investment Tax Credits	-	-	-	-
Local Income Taxes	-	-	-	-
Foreign Current Income Tax	-	-	-	-
Foreign Deferred Income Tax	-	-	-	-
Foreign Investment Tax Credits	-	-	-	-
Foreign Income Taxes	-	-	-	-
Total Income Taxes	2,981,164	(5,222,065)	(22,813,283)	31,016,512
Equity Earnings of Subs	-	-	-	-
INCOME AFTER INCOME TAXES and EQUITY EARNINGS	36,861,721	(15,014,320)	(63,047,460)	114,923,502
Discontinued Operations (Net of Taxes)	-	-	-	-
Cumulative Effect of Accounting Changes	-	-	-	-
Extraordinary Income / (Expenses)	-	-	-	-
NET INCOME	36,861,721	(15,014,320)	(63,047,460)	114,923,502
Minority Interest	-	-	-	-
Preferred Stock Dividend Subs	-	-	-	-
Earnings to Common Shareholders	36,861,721	(15,014,320)	(63,047,460)	114,923,502
NET INCOME (LOSS) NODE before PS	36,861,721	(15,014,320)	(63,047,460)	114,923,502
Double Check on Net Income Node after PS	-	-	-	-

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BS8216 YTD Dec 2024 01/10/2025 01:26	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024
	ASSETS				
	Cash and Cash Equivalents	**839,453**	**839,453**	**0**	**0**
	Other Cash Deposits	**22,976**	**12,667**	**10,042**	**267**
	Customers	18,369,294	14,872,704	846,296	2,650,294
	Accrued Unbilled Revenues	9,718,574	9,718,574	0	0
	Miscellaneous Accounts Receivable	19,307,356	6,790,713	61,088,591	19,903,682
	Allowances for Uncollectible Accounts	(605)	(605)	0	0
	Accounts Receivable	**47,394,618**	**31,381,386**	**61,934,887**	**22,553,977**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**83,630,408**	**6,434,775**	**73,928,115**	**3,267,518**
	Risk Management Contracts - Current	**5,254,522**	**0**	**5,254,522**	**0**
	Margin Deposits	**4,173,447**	**10,817**	**4,162,630**	**0**
	Unrecovered Fuel - Current	**8,634,580**	**0**	**8,634,580**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**2,352,244**	**1,786,361**	**388,706**	**177,177**
	TOTAL CURRENT ASSETS	**152,302,248**	**40,465,458**	**154,313,482**	**25,998,938**
	Electric Production	**1,290,637,497**	**1,329,757,497**	**1,324,754,059**	**955,494,283**
	Electric Transmission	**950,886,999**	**0**	**0**	**0**
	Electric Distribution	**1,194,542,636**	**0**	**0**	**0**
	General Property, Plant and Equipment	**175,096,240**	**83,276**	**(45,138)**	**1,119,396**
	Construction Work-in-Progress	**115,771,813**	**46,038,750**	**6,296,744**	**63,436,319**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,726,935,186**	**1,375,879,523**	**1,331,005,665**	**1,020,049,997**
	less: Accumulated Depreciation and Amortization	**(1,254,903,169)**	**(333,300,436)**	**(654,612,677)**	**(266,990,055)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,472,032,017**	**1,042,579,087**	**676,392,988**	**753,059,942**
	Net Regulatory Assets	**608,212,996**	**140,344,191**	**457,822,308**	**10,046,498**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**436,823**	**0**	**436,823**	**0**
	Employee Benefits and Pension Assets	**38,324,925**	**17,218,978**	**20,306,208**	**799,738**
	Other Non Current Assets	**44,897,768**	**13,955,538**	**24,373,228**	**6,569,001**
	TOTAL OTHER NON-CURRENT ASSETS	**691,872,512**	**171,518,707**	**502,938,568**	**17,415,237**
	TOTAL ASSETS	**3,316,206,777**	**1,254,563,252**	**1,333,645,038**	**796,474,118**
	LIABILITIES				
	Accounts Payable	**110,104,720**	**103,451,844**	**59,069,870**	**16,058,637**
	Advances from Affiliates	**183,212,284**	**(617,643,752)**	**1,062,041,887**	**(261,185,852)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**150,000,000**	**150,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	848,879	7,877	841,002	0
2440021	S/T Liability MTM Collateral	(394,887)	(7,877)	(387,010)	0
	Risk Management Liabilities - MTM	453,992	0	453,992	0
	Risk Management Liabilities	**453,992**	**0**	**453,992**	**0**
	Accrued Taxes	**40,464,197**	**(568,809)**	**(24,697,578)**	**65,730,584**
	Memo: Property Taxes	39,960,924	19,484,233	7,865,010	12,611,681
	Accrued Interest	**10,447,249**	**10,447,249**	**0**	**0**
	Risk Management Collateral	496,705	0	496,705	0
	Utility Customer Deposits	37,768,545	37,768,545	0	0

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BS8216 YTD Dec 2024 01/10/2025 01:26	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024
	Deposits - Customer and Collateral	**38,265,250**	**37,768,545**	**496,705**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	134,233	55,622	78,611	0
	Obligations under Operating Leases - Current	216,249	76,805	62,807	76,636
	Tax Collections Payable	2,568,209	2,568,209	0	0
	Revenue Refunds - Accrued	376,082	0	126,695	249,387
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	681,842	602,828	72,580	6,434
	Accrued Rents	0	0	0	0
	Accrued ICP	1,982,015	1,847,035	127,315	7,665
	Accrued Vacations	2,267,205	2,022,855	225,828	18,522
	Misc Employee Benefits	1,078,085	886,079	192,006	0
	Payroll Deductions	93,916	83,017	9,635	1,264
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	219,682	216,233	3,449	0
	Customer Advance	2,486,968	2,486,968	0	0
2420511	Control Cash Disburse Account	2,306,730	2,306,730	0	0
	Control Cash Disbursement Account	2,306,730	2,306,730	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	163,541	0	163,541	0
2300002	ARO - Current	3,620,144	0	3,620,144	0
2420083	Active Med and Dental IBNR	237,855	212,426	22,380	3,049
2420088	Econ. Development Fund Curr	625,396	625,396	0	0
2420512	Unclaimed Funds	16,001	16,001	0	0
2420542	Acc Cash Franchise Req	90,094	90,094	0	0
242059224	Sales Use Tax - Leased Equip	30	0	0	30
2420643	Accrued Audit Fees	(10,847)	(4,492)	(4,154)	(2,200)
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	135,288	134,952	0	336
2530112	Other Deferred Credits-Curr	63,453	63,453	0	0
2530124	Contr In Aid of Constr Advance	447,138	447,138	0	0
	Misc Current and Accrued Liabilities	5,388,778	1,585,651	3,801,911	1,215
	Current Other and Accrued Liabilities	19,449,511	14,605,605	4,559,419	284,488
	Other Current Liabilities	**19,799,993**	**14,738,032**	**4,700,837**	**361,124**
	TOTAL CURRENT LIABILITIES	**552,747,685**	**(301,806,891)**	**1,102,065,713**	**(179,035,507)**
	Long-Term Debt - Affiliated	**0**	**0**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,061,065,755**	**1,061,065,755**	**0**	**0**
2260006	Unam Disc LTD-Dr-Sr Unsec Not	(592,938)	(592,938)	0	0
	Long-Term Debt - Premiums and Discounts Unamort	**(592,938)**	**(592,938)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,060,472,818*	*1,060,472,818*	*0*	*0*
	Long-Term Risk Management Liabilities	**6,782**	**0**	**6,782**	**0**
	Deferred Income Taxes	**487,036,031**	**169,303,169**	**222,242,309**	**95,490,554**
	Deferred Investment Tax Credits	**0**	**0**	**0**	**0**
	Regulatory Liabilities and Deferred Credits	**118,345,468**	**88,414,245**	**(3,906,744)**	**33,837,967**
	Memo - Reg Liab and Def ITC	*118,345,468*	*88,414,245*	*(3,906,744)*	*33,837,967*
	Asset Retirement Obligation	**85,212,853**	**217,944**	**84,994,909**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**9,011,174**	**13,982,977**	**(6,738,726)**	**1,766,924**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redem	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	777,864	622,117	155,747	0
	Obligations Under Operating Leases	1,794,947	1,321,506	173,430	300,011

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BS8216 YTD Dec 2024 01/10/2025 01:26	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024	YTD Dec 2024
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	99,103	99,103	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	25,890	25,890	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	74	0	0	74
2530175	Legal Contingencies	(671)	(671)	0	0
2530185	O\U Accounting of ExpensesT	3,978	0	3,978	0
2530188	Long Term Assoc AP	8,187,226	0	0	8,187,226
2530190	QUAL OF SVC PENALTIES - LT	72,870	0	0	72,870
	Def Credits - Other	8,289,368	25,219	3,978	8,260,170
	Total Other Deferred Credits	8,388,471	124,323	3,978	8,260,170
	Accumulated Provisions - Rate Refund	1,497,209	0	0	1,497,209
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**12,458,491**	**2,067,945**	**333,155**	**10,057,390**
	TOTAL NON-CURRENT LIABILITIES	**1,772,543,616**	**1,334,459,098**	**296,931,684**	**141,152,835**
	TOTAL LIABILITIES	**2,325,291,301**	**1,032,652,206**	**1,398,997,397**	**(37,882,672)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,069,518**	**106,025,371**	**335,469,573**	**84,574,574**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**414,395,958**	**93,481,625**	**(411,109,535)**	**732,023,868**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**990,915,476**	**221,911,046**	**(65,352,359)**	**834,356,790**
	Memo: Total Equity	990,915,476	221,911,046	(65,352,359)	834,356,790
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,316,206,777**	**1,254,563,252**	**1,333,645,038**	**796,474,118**
	out-of-balance	(0)	0	0	(0)

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BS8216 YTD Dec 2023 01/22/2024 21:28	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Dec 2023	YTD Dec 2023	YTD Dec 2023	YTD Dec 2023
	ASSETS				
	Cash and Cash Equivalents	1,321,222	1,321,222	0	0
	Other Cash Deposits	55,764	22,325	32,470	969
	Customers	17,723,223	16,284,566	682,913	755,743
	Accrued Unbilled Revenues	0	0	0	0
	Miscellaneous Accounts Receivable	24,329,531	13,757,093	48,364,735	16,139,488
	Allowances for Uncollectible Accounts	(306)	(305)	(1)	0
	Accounts Receivable	42,052,447	30,041,354	49,047,647	16,895,231
	Advances to Affiliates	0	0	0	0
	Fuel, Materials and Supplies	106,082,334	7,737,784	95,601,042	2,743,508
	Risk Management Contracts - Current	3,063,513	0	3,063,513	0
	Margin Deposits	2,926,483	37,349	2,889,134	0
	Unrecovered Fuel - Current	10,687,804	0	10,687,804	0
	Other Current Regulatory Assets	0	0	0	0
	Prepayments and Other Current Assets	14,392,393	13,876,801	357,764	157,828
	TOTAL CURRENT ASSETS	180,581,961	53,036,836	161,679,374	19,797,536
	Electric Production	1,239,924,845	1,251,194,145	1,277,500,775	842,600,699
	Electric Transmission	838,263,665	0	0	0
	Electric Distribution	1,119,303,208	0	0	0
	General Property, Plant and Equipment	175,030,780	83,276	24,208	1,119,396
	Construction Work-in-Progress	159,612,262	59,962,192	24,445,914	75,204,157
	TOTAL PROPERTY, PLANT and EQUIPMENT	3,532,134,761	1,311,239,613	1,301,970,896	918,924,252
	less: Accumulated Depreciation and Amortization	(1,205,972,824)	(319,975,229)	(629,648,358)	(256,349,236)
	NET PROPERTY, PLANT and EQUIPMENT	2,326,161,937	991,264,384	672,322,538	662,575,015
	Net Regulatory Assets	553,099,868	129,210,706	416,038,149	7,851,013
	Securitized Transition Assets and Other	0	0	0	0
	Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
	Investments in Power and Distribution Projects	0	0	0	0
	Goodwill	0	0	0	0
	Long-Term Risk Management Assets	14,732	0	14,732	0
	Employee Benefits and Pension Assets	24,743,315	13,157,787	10,850,776	734,751
	Other Non Current Assets	53,721,059	16,082,812	28,198,713	9,439,534
	TOTAL OTHER NON-CURRENT ASSETS	631,578,974	158,451,305	455,102,370	18,025,299
	TOTAL ASSETS	3,138,322,872	1,202,752,525	1,289,104,282	700,397,850
	LIABILITIES				
	Accounts Payable	82,840,922	73,017,330	52,989,562	10,765,815
	Advances from Affiliates	49,567,376	(748,966,441)	995,116,107	(196,582,290)
	Short-Term Debt	0	0	0	0
	Other Current Regulatory Liabilities	0	0	0	0
	Long-Term Debt Due Within One Year Non-Affiliated	215,000,000	215,000,000	0	0
	Long-Term Debt Due Within One Year - Affiliated	0	0	0	0
	Risk Management Liabilities	7,925,921	0	7,925,921	0
	Accrued Taxes	48,910,684	14,900,608	(5,937,049)	39,947,125
	Memo: Property Taxes	47,453,550	23,292,703	8,528,198	15,632,650
	Accrued Interest	12,849,309	12,849,309	0	0

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BS8216 YTD Dec 2023 01/22/2024 21:28	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Dec 2023	YTD Dec 2023	YTD Dec 2023	YTD Dec 2023
	Risk Management Collateral	447,943	0	447,943	0
2350001	Customer Deposits-Active	37,578,928	37,578,928	0	0
	Utility Customer Deposits	37,578,928	37,578,928	0	0
	Deposits - Customer and Collateral	**38,026,871**	**37,578,928**	**447,943**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	111,992	35,310	76,682	0
	Obligations under Operating Leases - Current	195,155	134,116	59,144	1,895
	Tax Collections Payable	2,243,842	2,243,842	0	0
	Revenue Refunds - Accrued	609,403	0	134,716	474,687
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	500,350	441,056	54,733	4,561
	Accrued Rents	1,536	1,536	0	0
	Accrued ICP	1,673,370	1,544,352	122,203	6,814
	Accrued Vacations	2,417,019	2,165,356	234,088	17,575
	Misc Employee Benefits	1,429,266	680,129	748,607	530
	Payroll Deductions	114,781	90,118	23,391	1,272
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	177,339	166,351	10,988	0
2530022	Customer Advance Receipts	5,996,301	5,996,301	0	0
	Customer Advance	5,996,301	5,996,301	0	0
2420511	Control Cash Disburse Account	2,816,247	2,816,247	0	0
	Control Cash Disbursement Account	2,816,247	2,816,247	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	118,665	0	118,665	0
2300002	ARO - Current	205,678	0	205,678	0
2420000	Misc Current & Accrued Liab	12,000,000	12,000,000	0	0
2420088	Econ. Development Fund Curr	522,645	522,645	0	0
2420512	Unclaimed Funds	17,983	17,983	0	0
2420542	Acc Cash Franchise Req	79,087	79,087	0	0
2420643	Accrued Audit Fees	89,425	36,937	34,701	17,787
2420656	Federal Mitigation Accru (NSR)	244,045	0	244,045	0
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	155,419	155,039	0	380
2530112	Other Deferred Credits-Curr	58,439	56,995	76	1,367
2530124	Contr In Aid of Constr Advance	170,931	170,931	0	0
2530177	Deferred Rev-Bonus Lease Curr	5,692	0	5,692	0
	Misc Current and Accrued Liabilities	13,668,693	13,040,302	608,856	19,534
	Current Other and Accrued Liabilities	31,648,147	29,185,591	1,937,582	524,973
	Other Current Liabilities	**31,955,294**	**29,355,017**	**2,073,409**	**526,868**
	TOTAL CURRENT LIABILITIES	**487,076,377**	**(366,265,249)**	**1,052,615,893**	**(145,342,482)**
	Long-Term Debt - Affiliated	**25,000,000**	**25,000,000**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,060,466,101**	**1,060,466,101**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(660,063)**	**(660,063)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,059,806,039*	*1,059,806,039*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0

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BS8216 YTD Dec 2023 01/22/2024 21:28	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Dec 2023	YTD Dec 2023	YTD Dec 2023	YTD Dec 2023
2440002	LT Unreal Losses - Non Affil	973,993	0	973,993	0
	Long-Term Risk Management Liabilities - MTM	973,993	0	973,993	0
	Long-Term Risk Management Liabilities	**973,993**	**0**	**973,993**	**0**
	Deferred Income Taxes	**475,059,821**	**163,531,620**	**220,767,105**	**90,761,097**
	Deferred Investment Tax Credits	(0)	**0**	(0)	**0**
	Regulatory Liabilities and Deferred Credits	**97,627,442**	**70,252,900**	(1,433,781)	**28,808,323**
	Memo - Reg Liab and Def ITC	*97,627,441*	*70,252,900*	*(1,433,782)*	*28,808,323*
	Asset Retirement Obligation	**18,070,808**	**201,386**	**17,869,422**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**9,581,452**	**11,069,627**	(3,194,943)	**1,706,768**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redempt	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	677,350	465,726	211,624	0
	Obligations Under Operating Leases	962,879	736,956	225,923	0
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	94,091	94,091	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	40,407	40,407	0	0
2530101	MACSS Unidentified EDI Cash	1,375	1,375	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	962	0	0	962
2530185	O\U Accounting of ExpensesT	7,793	0	7,793	0
2530188	Long Term Assoc AP	4,099,784	0	0	4,099,784
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	4,234,936	41,782	7,793	4,185,362
	Total Other Deferred Credits	4,329,027	135,872	7,793	4,185,362
	Accumulated Provisions - Rate Refund	744,188	0	0	744,188
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**6,713,444**	**1,338,554**	**445,340**	**4,929,550**
	TOTAL NON-CURRENT LIABILITIES	**1,692,832,998**	**1,331,200,125**	**235,427,135**	**126,205,738**
	TOTAL LIABILITIES	**2,179,909,375**	**964,934,877**	**1,288,043,028**	(19,136,745)
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,771,323**	**106,025,371**	**336,070,072**	**84,675,880**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**381,192,173**	**109,388,228**	(345,296,421)	**617,100,367**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**958,413,497**	**237,817,648**	**1,061,254**	**719,534,595**
	Memo: Total Equity	958,413,497	237,817,648	1,061,254	719,534,595
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,138,322,872**	**1,202,752,525**	**1,289,104,282**	**700,397,850**

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KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - December, 2024

Final

GLR7210 01/10/25 10:40

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,276,923,610.03	61,956,422.94	(14,726,151.75)	0.00	0.00	1,324,153,881.22
101/106	CLOUD GENERATION	381,874.02	65,074.69	0.00	0.00	0.00	446,948.71
	TOTAL PRODUCTION	**1,277,305,484.05**	**62,021,497.63**	**(14,726,151.75)**	**0.00**	**0.00**	**1,324,600,829.93**
101/106	TRANSMISSION	842,600,699.05	119,748,237.25	(6,854,653.39)	0.00	0.00	955,494,282.91
101/106	CLOUD TRANSMISSION	201,394.70	101,436.90	0.00	0.00	0.00	302,831.60
101/106	DISTRIBUTION	1,249,889,192.92	92,777,026.36	(14,439,708.91)	0.00	0.00	1,328,226,510.37
101/106	CLOUD DISTRIBUTION	1,618,196.01	435,278.65	0.00	0.00	0.00	2,053,474.66
	TOTAL (ACCOUNTS 101 & 106)	**3,371,614,966.73**	**275,083,476.79**	**(36,020,514.05)**	**0.00**	**0.00**	**3,610,677,929.47**
1011001/12	CAPITAL LEASES	1,080,445.85	0.00	0.00	249,047.32	0.00	1,329,493.17
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**3,372,695,412.58**	**275,083,476.79**	**(36,020,514.05)**	**249,047.32**	**0.00**	**3,612,007,422.64**
1050001	PLANT HELD FOR FUTURE USE	801,671.21	0.00	0.00	0.00	0.00	801,671.21
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEGINNING BALANCE	159,612,262.17					
107000X	ADDITIONS		207,912,564.91				
107000X	TRANSFERS		(251,753,014.35)				
107000X	ENDING BALANCE		(43,840,449.44)				115,771,812.73
107000X	**CLOUD CONSTRUCTION WIP:**						
107000X	BEGINNING BALANCE	1,540,647.27					
107000X	ADDITIONS		874,658.58				
107000X	TRANSFERS		(601,790.24)				
107000X	ENDING BALANCE		272,868.34				1,813,515.61
	TOTAL ELECTRIC UTILITY PLANT	**3,534,649,993.23**	**231,515,895.69**	**(36,020,514.05)**	**249,047.32**	**0.00**	**3,730,394,422.19**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	571,711.48	0.00	(69,345.76)	0.00	0.00	502,365.72
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1210003	NONUTILITY PROPERTY-WIP						
	BEGINNING BALANCE	0.00					
	ADDITIONS		0.00				
	TRANSFERS		0.00				
	ENDING BALANCE		0.00				0.00
1210016	NONUTILITY PROPERTY-CCNC	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	655,168.37	0.00	0.00	0.00	0.00	655,168.37
	TOTAL NONUTILITY PLANT	**1,226,879.85**	**0.00**	**(69,345.76)**	**0.00**	**0.00**	**1,157,534.09**

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KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - December, 2024

Final

GLR7410 01/10/25 10:39

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
.	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	623,339,018.27	38,269,615.81	(11,017,664.36)	(6,088,511.26)	(4,118,311.49)	640,384,146.97
1080001/11	TRANSMISSION	284,929,166.47	24,052,362.66	(5,597,294.49)	(787,623.44)	0.00	302,596,611.20
1080001/11	DISTRIBUTION	376,851,080.91	45,012,626.71	(10,215,248.99)	(3,965,962.77)	(152,964.97)	407,529,530.89
1080013	PRODUCTION	(4,098,119.71)	0.00	0.00	0.00	4,098,119.71	0.00
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(151,934.59)	0.00	0.00	0.00	151,934.59	0.00
	RETIREMENT WORK IN PROGRESS	(13,358,319.70)	0.00	0.00	(11,710,887.91)	10,842,097.47	(14,227,110.14)
	TOTAL (108X accounts)	**1,267,510,891.66**	**107,334,605.18**	**(26,830,207.84)**	**(22,552,985.38)**	**10,820,875.31**	**1,336,283,178.93**
	NUCLEAR					0.00	
1110001	PRODUCTION	12,296,619.11	3,308,892.23	(3,708,487.39)	0.00	0.00	11,897,023.95
1110007	CLOUD IMPLEMENT COST PRODUCTI	103,001.61	82,157.06	0.00	0.00	0.00	185,158.67
1110001	TRANSMISSION	4,150,582.38	1,532,791.85	(1,257,358.90)	0.00	0.00	4,426,015.33
1110007	CLOUD IMPLEMENT COST TRANSMIS	36,477.38	49,908.09	0.00	0.00	0.00	86,385.47
1110001	DISTRIBUTION	14,363,824.54	4,705,254.89	(4,224,459.92)	0.00	0.00	14,844,619.51
1110007	CLOUD IMPLEMENT COST DISTRIBUT	417,883.25	315,048.43	0.00	0.00	0.00	732,931.68
	TOTAL (111X accounts)	**31,368,388.27**	**9,994,052.55**	**(9,190,306.21)**	**0.00**	**0.00**	**32,172,134.61**
1011006	CAPITAL LEASES	291,805.66	0.00	0.00	0.00	122,930.54	414,736.20
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**1,299,171,085.59**	**117,328,657.73**	**(36,020,514.05)**	**(22,552,985.38)**	**10,943,805.85**	**1,368,870,049.74**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	172,262.12	6,669.78	(69,345.76)	69,987.88	0.00	179,574.02
1220002	Depr&Amrt of Nonutl Prop-Leasd	0.00	0.00	0.00	0.00	0.00	0.00
1220003	Depr&Amrt of Nonutl Prop-WIP	69,987.88	0.00	0.00	0.00	(69,987.88)	0.00
1220004	Depletion - Owned	0.00	0.00	0.00	0.00	0.00	0.00
1240027	Other Property - RWIP	35,121.36	0.00	0.00	0.00	0.00	35,121.36
1240028	Other Property - Retirement	(46,947.27)	0.00	0.00	0.00	0.00	(46,947.27)
	TOTAL NONUTILITY PLANT	**230,424.09**	**6,669.78**	**(69,345.76)**	**69,987.88**	**(69,987.88)**	**167,748.11**

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U.S. Department of Energy
Energy Information Administration
Form EIA-826

Monthly Electric Utility Sales and Revenue Report with State Distributions – 2024

Form Approval
OMB NO.1905-0129
(Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**

Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650.

Utility Name: Kentucky Power Company **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan___ Feb___ Mar___ Apr___ May___ Jun___ Jul___ Aug___ Sep___ Oct___ Nov___ Dec_X_ , 2024

Contact Person: Sandra Vargo	**Phone number: 614-716-2714**
Email: slvargo@aep.com	**Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	$ 32,588	$ 18,237	$ 14,807	$ -	$ 65,632
	b. Megwatthours	205,186	118,319	162,397	-	485,902
	c. Number of consumers	130,936	30,718	937	-	162,591
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					

Note:

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February 28th, 2025

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed January 2025 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:	
1-12	Income Statement
1-3	Details of Operating Revenues
5-10	Operating Expenses – Functional Expenses
12	Detail Statement of Taxes
Balance Sheet:	
13	Balance Sheet – Assets & Other Debits
13-15	Balance Sheet – Liabilities & Other Credits
14-15	Deferred Credits
15	Statement of Retained Earnings
Utility Property:	
16-17	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Digitally signed by Brian J. Frantz
DN: cn=Brian J. Frantz, o=AEP, ou=Corporate Accounting, email=bjfrantz@aep.com
Reason: I have reviewed this document
Date: 2025.02.28 11:23:14 -05'00'

Brian J Frantz
Director - Corporate Accounting

American Electric Power

INCOME STATEMENT

IS8016
YTD Jan 2025
02/16/2025 19:05

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Jan 2025	Kentucky Power Company - Distribution 110 Actual YTD Jan 2025	Kentucky Power Company - Generation 117 Actual YTD Jan 2025	Kentucky Power Company - Transmission 180 Actual YTD Jan 2025
		REVENUES				
4400001		Residential Sales-W/Space Htg	21,899,122	22,168,675	(269,554)	0
4400002		Residential Sales-W/O Space Ht	7,798,814	8,106,160	(307,346)	0
4400005		Residential Fuel Rev	11,449,952	11,449,952	0	0
	A	**Revenue - Residential Sales**	**41,147,887**	**41,724,787**	**(576,900)**	**-**
4420001		Commercial Sales	9,756,332	10,061,296	(304,964)	0
4420006		Sales to Pub Auth - Schools	1,608,929	1,608,929	0	0
4420007		Sales to Pub Auth - Ex Schools	1,955,065	2,003,884	(48,819)	0
4420013		Commercial Fuel Rev	5,862,943	5,862,943	0	0
	A	**Revenue - Commercial Sales**	**19,183,269**	**19,537,053**	**(353,784)**	**-**
	B	**Revenue - Industrial Sales - Affiliated**	**-**	**-**	**-**	**-**
4420002		Industrial Sales (Excl Mines)	5,985,418	6,353,501	(368,083)	0
4420004		Ind Sales-NonAffil(Incl Mines)	1,548,190	1,548,190	0	0
4420016		Industrial Fuel Rev	6,561,407	6,561,407	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**14,095,015**	**14,463,099**	**(368,083)**	**-**
		Revenue - Industrial Sales	**14,095,015**	**14,463,099**	**(368,083)**	**-**
	A	**Revenue - Gas Products Sales**	**-**	**-**	**-**	**-**
	A	**Revenue - Gas Transportation & Storage Sales**	**-**	**-**	**-**	**-**
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	**-**	**-**	**-**	**-**
4440000		Public Street/Highway Lighting	158,478	159,566	(1,088)	0
4440002		Public St & Hwy Light Fuel Rev	36,593	36,593	0	0
	A	**Revenue - Other Retail Sales**	**195,071**	**196,158**	**(1,088)**	**-**
	B	**Revenue - Other Retail Sales - Affiliated**	**-**	**-**	**-**	**-**
		Revenue - Retail Sales	**74,621,242**	**75,921,097**	**(1,299,855)**	**-**
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	9,689,773
4561033		PJM NITS Revenue - Affiliated	7,552,626	0	0	7,552,626
4561034		PJM TO Adm. Serv Rev - Aff	19,433	0	0	19,433
4561035		PJM Affiliated Trans NITS Cost	(4,916,437)	0	(4,916,437)	0
4561036		PJM Affiliated Trans TO Cost	(11,217)	0	(11,217)	0
4561059		Affil PJM Trans Enhancmnt Rev	137,339	0	0	137,339
4561060		Affil PJM Trans Enhancmnt Cost	(89,402)	0	(89,402)	0
4561062		PROVISION RTO Cost - Affi	138,615	0	138,615	0
4561063		PROVISION RTO Rev Affiliated	(27,389)	0	0	(27,389)
	B	**Revenue - Transmission-Affiliated**	**2,803,569**	**-**	**(4,878,440)**	**17,371,782**
4470150		Transm. Rev.-Dedic. Whlsl/Muni	(2,477)	0	(220,012)	217,535
4470206		PJM Trans loss credits-OSS	10,543	0	10,543	0
4470209		PJM transm loss charges-OSS	(18,613)	0	(18,613)	0
4561005		PJM Point to Point Trans Svc	338,806	0	338,806	0
4561006		PJM Trans Owner Admin Rev	9,762	0	0	9,762
4561007		PJM Network Integ Trans Svc	1,016,243	0	0	1,016,243
4561019		Oth Elec Rev Trans Non Affil	7,193	0	0	7,193
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	22	0	0	22
4561029		PJM NITS Revenue Whsl Cus-NAff	256,640	0	0	256,640
4561030		PJM TO Serv Rev Whls Cus-NAff	647	0	0	647
4561045		PJM Non-Aff Gen IPP Rev	1,994	0	0	1,994

American Electric Power

INCOME STATEMENT

IS8016
YTD Jan 2025
02/16/2025 19:05

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Jan 2025	Kentucky Power Company - Distribution 110 Actual YTD Jan 2025	Kentucky Power Company - Generation 117 Actual YTD Jan 2025	Kentucky Power Company - Transmission 180 Actual YTD Jan 2025
4561058		NonAffil PJM Trans Enhncmt Rev	157,705	0	0	157,705
4561061		NAff PJM RTEP Rev for Whsl-FR	4,667	0	0	4,667
4561064		PROVISION RTO Rev WhslCus-NAf	(920)	0	0	(920)
4561065		PROVISION RTO Rev - NonAff	(4,115)	0	0	(4,115)
	A	**Revenue - Transmission-NonAffiliated**	**1,778,095**	**-**	**110,724**	**1,667,371**
		Revenue - Transmission	**4,581,664**	**-**	**(4,767,717)**	**19,039,153**
	B	**Revenue - Resale-Affiliated**	**-**	**-**	**-**	**-**
4470027		Whsal/Muni/Pb Ath Fuel Rev	377,771	0	377,771	0
4470033		Whsal/Muni/Pub Auth Base Rev	270,508	0	270,508	0
4470082		Financial Electric Realized	(201)	0	(201)	0
4470089		PJM Energy Sales Margin	215,057	0	215,057	0
4470098		PJM Oper.Reserve Rev-OSS	(6,944)	0	(6,944)	0
4470099		Capacity Cr. Net Sales	(10,446)	0	(10,446)	0
4470100		PJM FTR Revenue-OSS	24,880	0	24,880	0
4470103		PJM Energy Sales Cost	1,294,413	0	1,294,413	0
4470115		PJM Meter Corrections-OSS	(926)	0	(926)	0
4470116		PJM Meter Corrections-LSE	(17,120)	0	(17,120)	0
4470126		PJM Incremental Imp Cong-OSS	(13,135)	0	(13,135)	0
4470175		OSS Sharing Reclass - Retail	(599,339)	0	(599,339)	0
4470176		OSS Sharing Reclass-Reduction	599,339	0	599,339	0
4470220		PJM Regulation - OSS	627,127	0	627,127	0
4470221		PJM Spinning Reserve - OSS	8,819	0	8,819	0
5550080		PJM Hourly Net Purch.-FERC	(783,483)	0	(783,483)	0
	A	**Revenue - Resale-NonAffiliated**	**1,986,321**	**-**	**1,986,321**	**-**
	A	**Revenue - Resale-Realized**	**-**	**-**	**-**	**-**
	A	**Revenue - Resale-Risk Mgmt MTM**	**-**	**-**	**-**	**-**
	A	**Revenue - Resale-Risk Mgmt Activities**	**-**	**-**	**-**	**-**
		Revenue - Sales for Resale	**1,986,321**	**-**	**1,986,321**	**-**
4470074		Sale for Resale-Aff-Trnf Price	0	0	47,809,117	0
4540001		Rent From Elect Property - Af	186,737	97,251	0	123,490
	B	**Revenue - Other Ele-Affilliated**	**186,737**	**97,251**	**47,809,117**	**123,490**
4500000		Forfeited Discounts	118,690	118,690	0	0
4510001		Misc Service Rev - Nonaffil	6,667	6,593	0	74
4540002		Rent From Elect Property-NAC	211,328	175	210,678	475
4540005		Rent from Elec Prop-Pole Attch	395,187	394,563	0	624
4560007		Oth Elect Rev - DSM Program	35,556	35,556	0	0
5010040		Gas Procuremnt Sales Net	(122,979)	0	(122,979)	0
		Revenue - Other Ele-NonAffilliated	**644,450**	**555,578**	**87,699**	**1,173**
		Revenue - Gas	**-**	**-**	**-**	**-**
		Gain/(Loss) on Allowances	**-**	**-**	**-**	**-**
	A	**Revenue - Other Ele-NonAffilliated**	**644,450**	**555,578**	**87,699**	**1,173**
		Revenue - Other Opr Electric	**831,188**	**652,829**	**47,896,816**	**124,663**
	D	**Revenue Merchandising & Contract Work**	**-**	**-**	**-**	**-**
	C	**Revenues Non-Utility Operations - Affiliated**	**-**	**-**	**-**	**-**
4170004		Rev from Non-Util Oper NonAfil	28,988	28,988	0	0

American Electric Power

INCOME STATEMENT

IS8016
YTD Jan 2025
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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Jan 2025	Kentucky Power Company - Distribution 110 Actual YTD Jan 2025	Kentucky Power Company - Generation 117 Actual YTD Jan 2025	Kentucky Power Company - Transmission 180 Actual YTD Jan 2025
D	**Revenues Non-Utility Operations - NonAffiliated**	**28,988**	**28,988**	**-**	**-**
	Revenues from Non-Utility Operations	**28,988**	**28,988**	**-**	**-**
C	**Non-Operating Rental Income - Affiliated**	**-**	**-**	**-**	**-**
4180005	Non-Opratng Rntal Inc-Depr	(556)	0	0	(556)
D	**Non-Operating Rental Income - NonAffiliated**	**(556)**	**-**	**-**	**(556)**
	Non-Operating Rental Income	**(556)**	**-**	**-**	**(556)**
C	**Non-Operating Misc Income -Affiliated**	**-**	**-**	**-**	**-**
4210002	Misc Non-Op Inc-NonAsc-Rents	62	0	62	0
4210007	Misc Non-Op Inc - NonAsc - Oth	83	75	8	0
D	**Non-Operating Misc Income - NonAffiliated**	**145**	**75**	**70**	**-**
	Non-Operating Misc Income	**145**	**75**	**70**	**-**
4560015	Other Electric Revenues - ABD	61,701	61,701	0	0
D	**Associated Business Development Income**	**61,701**	**61,701**	**-**	**-**
	Revenue - Other Opr - Other	**90,279**	**90,764**	**70**	**(556)**
=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	**-**	**-**	**-**	**-**
=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***90,279***	***90,764***	***70***	***(556)***
	Revenue - Other Operating	**921,466**	**743,593**	**47,896,887**	**124,107**
4491002	Prov Rate Refund-Nonaffiliated	(15,607)	0	0	(15,607)
4491003	Prov Rate Refund - Retail	(3,541)	0	0	(3,541)
A	**Provision for Rate Refund - NonAffiliated**	**(19,148)**	**-**	**-**	**(19,148)**
4491004	Prov Rate Refund - Affiliated	(104,520)	0	0	(104,520)
B	**Provision for Rate Refund - Affiliated**	**(104,520)**	**-**	**-**	**(104,520)**
	Provision for Rate Refund	**(123,668)**	**-**	**-**	**(123,668)**
A	**Revenue - Power Sales**	**-**	**-**	**-**	**-**
	TOTAL OPERATING REVENUES	**81,987,025**	**76,664,690**	**43,815,636**	**19,039,592**
=(A)	*Memo: G/T/D Revenue*	*79,010,961*	*76,476,675*	*884,890*	*1,649,396*
=(B)	*Memo: Other Affiliated Revenue*	*2,885,786*	*97,251*	*42,930,676*	*17,390,751*
=(C)	*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
=(D)	*Memo: Revenue-Oth Opr-Oth Nor*	*90,279*	*90,764*	*70*	*(556)*
	Memo: Total Operating Revenues	*81,987,025*	*76,664,690*	*43,815,636*	*19,039,592*
=(E)=(B)+(C)	*Memo: Affiliated Revenue*	***2,885,786***	***97,251***	***42,930,676***	***17,390,751***
=(F)=(D)+(A)	*Memo: Non-Affiliated Revenue*	***79,101,239***	***76,567,439***	***884,960***	***1,648,841***
	Memo: Total Operating Revenues	***81,987,025***	***76,664,690***	***43,815,636***	***19,039,592***
	FUEL EXPENSES				
5010000	Fuel	618,298	0	618,298	0
5010001	Fuel Consumed	12,290,393	0	12,290,393	0
5010003	Fuel - Procure Unload & Handle	617,385	0	617,385	0
5010012	Ash Sales Proceeds	993	0	993	0
5010019	Fuel Oil Consumed	170,057	0	170,057	0
5010020	Nat Gas Consumed Steam	4,815,548	0	4,815,548	0
5010021	Transp Gas Consumed Steam	27,014	0	27,014	0
5010027	Gypsum handling/disposal costs	65,969	0	65,969	0
5010028	Gypsum Sales Proceeds	(242,087)	0	(242,087)	0

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IS8016 YTD Jan 2025 02/16/2025 19:05	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025
5010034	Gas Transp Res Fees-Steam	554,414	0	554,414	0
	Fuel Expense Total	**18,917,984**	**-**	**18,917,984**	**-**
5010005	Fuel - Deferred	(5,123,319)	0	(5,123,319)	0
	Deferred Fuel Expense	**(5,123,319)**	**-**	**(5,123,319)**	**-**
	Over Under Fuel Expense				
	Fuel for Electric Generation	**13,794,665**	**-**	**13,794,665**	**-**
	Fuel from Affiliates for Electric Generation	**-**	**-**	**-**	**-**
5090000	Allow Consum Title IV SO2	2,913	0	2,913	0
5090009	Allow Consumpt CSAPR SO2	14	0	14	0
	Allowances - Consumption	**2,928**	**-**	**2,928**	**-**
5020002	Urea Expense	178,813	0	178,813	0
5020004	Lime-Related Expenses	293,674	0	293,674	0
	Emissions Control - Chemicals	**472,487**	**-**	**472,487**	**-**
	Total Fuel for Electric Generation	**14,270,079**	**-**	**14,270,079**	**-**
	Memo: NonAff Fuel/Allow/Emissions	***14,270,079***	**-**	***14,270,079***	**-**
5550029	Purch Power-Assoc-Trnsfr Price	0	47,809,117	0	0
	Purchased Electricity from AEP - Affiliates	**-**	**47,809,117**	**-**	**-**
5550001	Purch Pwr-NonTrading-Nonassoc	15,205,503	0	15,205,503	0
5550023	Purch Power Capacity -NA	201,548	0	201,548	0
5550039	PJM Inadvertent Mtr Res-OSS	(507)	0	(507)	0
5550040	PJM Inadvertent Mtr Res-LSE	(3,525)	0	(3,525)	0
5550074	PJM Reactive-Charge	286,667	0	286,667	0
5550075	PJM Reactive-Credit	(119,573)	0	(119,573)	0
5550076	PJM Black Start-Charge	3,384	0	3,384	0
5550078	PJM Regulation-Charge	127,637	0	127,637	0
5550079	PJM Regulation-Credit	215,935	0	215,935	0
5550083	PJM Sync & Non Sync-Charge	102,439	0	102,439	0
5550084	PJM Sync & Non Sync-Credit	(8,869)	0	(8,869)	0
5550123	PJM OpRes-LSE-Charge	2,956,749	0	2,956,749	0
5550124	PJM Implicit Congestion-LSE	1,254,435	0	1,254,435	0
5550132	PJM FTR Revenue-LSE	(4,080,094)	0	(4,080,094)	0
5550137	PJM OpRes-LSE-Credit	(11,216)	0	(11,216)	0
5550326	PJM Transm Loss Charges - LSE	1,575,294	0	1,575,294	0
5550327	PJM Transm Loss Credits-LSE	(720,313)	0	(720,313)	0
5550328	PJM FC Penalty Credit	(935)	0	(935)	0
	Purchased Electricity for Resale - NonAffiliated	**16,984,558**	**-**	**16,984,558**	**0**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**
	Purchased Gas for Resale - NonAffiliated	**-**	**-**	**-**	**-**
	Total Purchased Power	**16,984,558**	**47,809,117**	**16,984,558**	**0**
	GROSS MARGIN	**50,732,388**	**28,855,573**	**12,560,999**	**19,039,592**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	336,540	1,130	334,766	644
5020000	Steam Expenses	263,752	0	263,752	0
5050000	Electric Expenses	1,444	0	1,444	0

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IS8016 YTD Jan 2025 02/16/2025 19:05	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025
5060000	Misc Steam Power Expenses	417,842	(19,302)	436,364	780
5060002	Misc Steam Power Exp-Assoc	4,967	0	4,967	0
5070006	Rents - Associated	193	0	193	0
	Steam Generation Op Exp	**1,024,739**	**(18,172)**	**1,041,487**	**1,424**
	Nuclear Generation Op Exp	**-**	**-**	**-**	**-**
	Hydro Generation Op Exp	**-**	**-**	**-**	**-**
5560000	Sys Control & Load Dispatching	5,359	0	5,359	0
5570000	Other Expenses	65,628	0	65,628	0
5570007	Other Pwr Exp - Wholesale RECs	243	243	0	0
5581400	Wind Turb Gen&Oth Plnt Op-Mjr	413	0	413	0
5757000	PJM Admin-MAM&SC- OSS	6,761	0	6,761	0
5757001	PJM Admin-MAM&SC- Internal	158,273	0	158,273	0
	Other Generation Op Exp	**236,678**	**243**	**236,435**	**-**
5600000	Oper Supervision & Engineering	228,556	6,728	2,026	219,803
5612000	Load Dispatch-Mntr&Op TransSys	39,358	40	5	39,313
5613000	Load Dispatch-Trans Srvc&Sched	192	0	0	192
5614000	PJM Admin-SSC&DS-OSS	6,581	0	6,581	0
5614001	PJM Admin-SSC&DS-Internal	145,000	0	145,000	0
5615000	Reliability,Plng&Stds Develop	5,237	66	9	5,162
5618000	PJM Admin-RP&SDS-OSS	3,337	0	3,337	0
5618001	PJM Admin-RP&SDS- Internal	59,349	0	59,349	0
5620001	Station Expenses - Nonassoc	25,544	0	0	25,544
5630000	Overhead Line Expenses	865	0	0	865
5650002	Transmssn Elec by Others-NAC	15,075	0	15,075	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	9,689,773	0	0
5650012	PJM Trans Enhancement Charge	167,900	0	167,900	0
5650015	PJM TO Serv Exp - Aff	19,216	0	19,216	0
5650016	PJM NITS Expense - Affiliated	6,501,533	0	6,501,533	0
5650019	Affil PJM Trans Enhncement Exp	398,851	0	398,851	0
5650020	PROVISION RTO Affl Expense	(147,629)	0	(147,629)	0
5650021	PJM NITS Expense - Non-Affilia	84,543	0	84,543	0
5650023	Amort of PROVISION RTO Expense	793,952	0	793,952	0
5660000	Misc Transmission Expenses	43,288	(52,467)	195	95,560
5660011	Misc Transm Exp - Affiliate	268	0	0	268
5670002	Rents - Associated	0	0	0	34,004
	Transmission Op Exp	**8,391,017**	**9,644,138**	**8,049,944**	**420,711**
5800000	Oper Supervision & Engineering	(27,864)	(30,128)	95	2,173
5810000	Load Dispatching	79	79	0	0
5820000	Station Expenses	19,031	16,203	5	2,823
5830000	Overhead Line Expenses	81,810	81,870	0	(18)
5840000	Underground Line Expenses	31,578	31,526	0	52
5850000	Street Lighting & Signal Sys E	1,741	1,742	0	0
5860000	Meter Expenses	73,928	74,031	0	0
5870000	Customer Installations Exp	9,964	9,980	0	(6)
5880000	Miscellaneous Distribution Exp	61,827	58,043	375	3,498

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IS8016 YTD Jan 2025 02/16/2025 19:05	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
17A V2099-01-01	Layout: IS8016 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025
5890001	Rents - Nonassociated	156,604	156,604	0	0
5890002	Rents - Associated	1,031	1,031	0	0
	Distribution Op Exp	**409,729**	**400,982**	**475**	**8,522**
9010000	Supervision - Customer Accts	1,501	1,513	(3)	(9)
9020000	Meter Reading Expenses	738	738	0	0
9020002	Meter Reading - Regular	28,318	28,337	0	0
9020003	Meter Reading - Large Power	2,823	2,823	0	0
9030000	Cust Records & Collection Exp	28,308	27,871	8	429
9030001	Customer Orders & Inquiries	230,677	230,352	95	235
9030002	Manual Billing	628	628	0	0
9030003	Postage - Customer Bills	55,166	55,166	0	0
9030004	Cashiering	4,161	4,161	0	0
9030005	Collection Agents Fees & Exp	525	525	0	0
9030006	Credit & Oth Collection Activi	13,317	13,326	0	0
9030007	Collectors	17,269	17,269	0	0
9030009	Data Processing	(315)	(315)	0	0
9040007	Uncoll Accts - Misc Receivable	(5,859)	(5,859)	0	0
9050000	Misc Customer Accounts Exp	1,453	1,453	0	0
9070000	Supervision - Customer Service	2,105	2,113	0	(7)
9080000	Customer Assistance Expenses	67,282	67,286	0	0
9080004	Cust Assistnce Exp - DSM - Ind	21	21	0	0
9080009	Cust Assistance Expense - DSM	35,331	35,331	0	0
9100000	Misc Cust Svc&Informational Ex	1,529	705	406	418
9100001	Misc Cust Svc & Info Exp - RCS	(62)	(34)	0	(28)
	Customer Service and Information Op Exp	**484,916**	**483,410**	**506**	**1,037**
9120000	Demonstrating & Selling Exp	316	316	0	0
	Sales Expenses	**316**	**316**	**-**	**-**
	Memo: Insurance (9240 9250)	**171,437**	**54,387**	**91,659**	**25,391**
9200000	Administrative & Gen Salaries	1,097,330	542,601	350,218	204,514
9210001	Off Supl & Exp - Nonassociated	272,207	168,955	83,235	20,033
9210024	EMP TRAVEL-PARKING	1	0	0	0
9210025	MEALS & ENT-50 Pct DEDUCTIBLE	1	1	0	0
9210026	EMP TRAVEL-CAR RENTAL	3	2	1	0
9210028	EMP TRAVEL-HOTEL & LODGING	6	4	2	0
9210041	VEHICLE-LICENSE FEES	4	1	2	1
9220000	Administrative Exp Trnsf - Cr	(8,632)	(8,632)	0	0
9220001	Admin Exp Trnsf to Cnstrction	(35,793)	(35,793)	0	0
9220004	Admin Exp Trnsf to ABD	(64)	(64)	0	0
9220005	Overhead Loadings	(57,164)	(40,828)	(11,768)	(4,569)
9230001	Outside Svcs Empl - Nonassoc	224,389	59,261	90,678	74,451
9230003	AEPSC Billed to Client Co	(245,473)	(85,503)	(83,885)	(76,084)
9230034	SRV-SOFTWARE LICENSING	982	744	229	9
9230064	Def AEPSC Pension Settlement	3,464	1,242	1,108	1,114
9240000	Property Insurance	92,444	23,532	52,474	16,438
9250000	Injuries and Damages	160,458	110,449	41,264	8,745

American Electric Power

IS8016 YTD Jan 2025 02/16/2025 19:05	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025
9250002	Emp Accdent Prvntion-Adm Exp	(95)	(32)	(34)	(29)
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	(65,862)	(64,097)	(2,044)	280
9250007	Prsnal Injries&Prop Dmage-Pub	442	0	442	0
9250010	Frg Ben Loading - Workers Comp	(15,951)	(15,464)	(443)	(44)
9260000	Employee Pensions & Benefits	203	203	0	0
9260002	Pension & Group Ins Admin	3,187	1,465	1,673	49
9260003	Pension Plan	169,492	112,140	55,906	1,447
9260004	Group Life Insurance Premiums	11,284	7,380	3,841	62
9260005	Group Medical Ins Premiums	287,477	203,162	80,659	3,655
9260007	Group L-T Disability Ins Prem	36,089	20,859	15,195	36
9260009	Group Dental Insurance Prem	13,337	9,061	4,139	136
9260010	Training Administration Exp	2,895	1,959	910	25
9260012	Employee Activities	611	390	219	2
9260021	Postretirement Benefits - OPEB	6,816	3,696	3,028	93
9260027	Savings Plan Contributions	150,070	98,750	50,374	947
9260037	Supplemental Pension	552	497	56	0
9260050	Frg Ben Loading - Pension	(54,143)	(45,673)	(7,530)	(941)
9260051	Frg Ben Loading - Grp Ins	(143,886)	(120,475)	(21,008)	(2,403)
9260052	Frg Ben Loading - Savings	(49,567)	(40,332)	(8,514)	(721)
9260053	Frg Ben Loading - OPEB	(2,408)	(1,654)	(656)	(97)
9260055	IntercoFringeOffset- Don't Use	(26,821)	(26,821)	0	0
9260058	Frg Ben Loading - Accrual	(37,275)	(31,232)	(3,688)	(2,354)
9270000	Franchise Requirements	13,362	13,362	0	0
9280000	Regulatory Commission Exp	3,716	1,616	1,076	1,024
9280002	Regulatory Commission Exp-Case	164,607	75,778	34,106	54,722
9280005	Reg Com Exp-FERC Trans Cases	1,089	127	99	863
9280006	State Publ Serv CommissionFees	79,433	79,433	0	0
9301012	Public Opinion Surveys	1,391	1,391	0	0
9301015	Other Corporate Comm Exp	32	32	0	0
9302000	Misc General Expenses	9,682	3,773	2,952	2,957
9302003	Corporate & Fiscal Expenses	10,957	9,236	1,381	340
9310001	Rents - Real Property	800	800	0	0
9310002	Rents - Personal Property	4,265	3,615	604	46
	Administration & General	**2,079,942**	**1,038,915**	**736,299**	**304,748**
4111005	Accretion Expense	192,467	1,531	190,935	0
	Accretion	**192,467**	**1,531**	**190,935**	**-**
4116000	Gain From Disposition of Plant	(1,381)	(1,381)	0	0
	Loss/(Gain) on Utility Plant	**(1,381)**	**(1,381)**	**-**	**-**
9302006	Assoc Bus Dev - Materials Sold	13,026	12,996	0	30
9302007	Assoc Business Development Exp	12,619	10,506	12	2,105
	Associated Business Development Expenses	**25,645**	**23,501**	**12**	**2,135**
	Gain on Disposition of Property	**-**	**-**	**-**	**-**
	Loss on Disposition of Property	**-**	**-**	**-**	**-**
	Loss(Gain) of Sale of Property	**-**	**-**	**-**	**-**
4265009	Factored Cust A/R Exp - Affil	290,155	290,155	0	0

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IS8016 YTD Jan 2025 02/16/2025 19:05	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025
4265010	Fact Cust A/R-Bad Debts-Affil	104,619	104,619	0	0
	Opr Exp and Factored A/R	**394,774**	**394,774**	**-**	**-**
	Water Heaters	**-**	**-**	**-**	**-**
4040007	Cloud Implement - Amort Plant	42,430	29,934	7,449	5,047
4265004	Social & Service Club Dues	665	665	0	0
4265007	Regulatory Expenses	440	194	125	121
	Expense of Non-Utility Operation	**43,535**	**30,793**	**7,574**	**5,168**
4210009	Misc Non-Op Exp - NonAssoc	343	141	91	111
	Misc NonOp Expenses - NonAssoc	**343**	**141**	**91**	**111**
4261000	Donations	134,961	134,782	69	110
	Donation Contributions	**134,961**	**134,782**	**69**	**110**
4263001	Penalties	1	1	1	0
	Provision for Penalties	**1**	**1**	**1**	**0**
4264000	Civic and Political Activity	6,040	2,779	1,637	1,625
	Civic & Political Activities	**6,040**	**2,779**	**1,637**	**1,625**
4265002	Other Deductions - Nonassoc	10,620	603	325	9,692
	Other Deductions	**10,620**	**603**	**325**	**9,692**
	Shutdown Coal Company Expenses	**-**	**-**	**-**	**-**
	All Other Operational Expenses	**590,276**	**563,873**	**9,697**	**16,707**
	Operational Expenses	**13,434,344**	**12,137,356**	**10,265,791**	**755,285**
5100000	Maint Supv & Engineering	88,725	0	88,725	0
5110000	Maintenance of Structures	145,729	0	145,729	0
5120000	Maintenance of Boiler Plant	932,570	0	932,570	0
5120034	BSDR O/U Recovery - Maint Cost	(189)	0	(189)	0
5120037	KY Steam Maint O/U	(58,271)	0	(58,271)	0
5130000	Maintenance of Electric Plant	297,751	0	297,751	0
5140000	Maintenance of Misc Steam Plt	109,605	0	109,605	0
	Steam Generation Maintenance	**1,515,919**	**-**	**1,515,919**	**0**
	Nuclear Generation Maintenance	**-**	**-**	**-**	**-**
	Hydro Generation Maintenance	**-**	**-**	**-**	**-**
5581900	Maint Wind Turb Struct&Eq-Mjr	2	0	2	0
5587000	Maint Solar Pnl Strct & Eq-Mjr	1	0	1	0
	Other Generation Maintenance	**3**	**-**	**3**	**-**
5680000	Maint Supv & Engineering	912	0	58	854
5690000	Maintenance of Structures	4,281	0	0	4,281
5691000	Maint of Computer Hardware	591	49	20	523
5692000	Maint of Computer Software	12,378	0	0	12,378
5693000	Maint of Communication Equip	3,001	0	0	3,001
5700000	Maint of Station Equipment	98,276	4	8	98,264
5710000	Maintenance of Overhead Lines	162,650	0	0	162,650
5720000	Maint of Underground Lines	234	0	0	234
5730000	Maint of Misc Trnsmssion Plt	453	0	0	453
	Transmission Maintenance	**282,776**	**53**	**86**	**282,637**
5900000	Maint Supv & Engineering	2,800	2,581	0	220
5910000	Maintenance of Structures	(3)	0	0	(3)

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	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025
5920000	Maint of Station Equipment	43,864	38,830	65	4,969
5923000	Maint of Computer Software-Mjr	8,773	8,773	0	0
5924000	Maint of Comm Equipmt-Mjr	89,134	89,134	0	0
5930000	Maintenance of Overhead Lines	7,277,329	7,278,056	43	817
5930001	Tree and Brush Control	22,972	22,989	0	0
5940000	Maint of Underground Lines	1,719	1,720	0	0
5950000	Maint of Lne Trnf,Rglators&Dvi	(88)	(100)	0	12
5960000	Maint of Strt Lghtng & Sgnal S	279	279	0	0
5970000	Maintenance of Meters	3,336	3,339	0	0
5980000	Maint of Misc Distribution Plt	1,540	1,483	1	56
	Distribution Maintenance	**7,451,656**	**7,447,085**	**109**	**6,071**
9350000	Maintenance of General Plant	445	445	0	0
9350001	Maint of Structures - Owned	18,751	18,765	(5)	(10)
9350002	Maint of Structures - Leased	230	155	75	0
9350013	Maint of Cmmncation Eq-Unall	(93)	0	(0)	0
9350015	Maint of Office Furniture & Eq	0	0	0	0
9350024	Maint of DA-AMI Comm Equip	0	0	0	0
9352000	Maint of Computer Software	61,868	24,744	33,210	3,914
9353000	Maint of Comm Equipmt	7,511	5,828	1,389	294
	Administration & General Maintenance	**88,711**	**49,937**	**34,669**	**4,198**
	All Other Maintenance Expenses	**-**	**-**	**-**	**-**
	Maintenance Expenses	**9,339,065**	**7,497,075**	**1,550,785**	**292,907**
	Total Operational and Maintenance Expenses	**22,773,409**	**19,634,431**	**11,816,576**	**1,048,192**
4040001	Amort. of Plant	751,363	389,676	240,866	120,821
4060001	Amort of Plt Acq Adj	3,218	0	0	3,218
	DDA Amortization	**754,581**	**389,676**	**240,866**	**124,039**
4073014	Regulatory Debit - BSDR	17,055	0	17,055	0
	DDA Regulatory Debits	**17,055**	**-**	**17,055**	**-**
4074000	Regulatory Credits	(40,681)	(40,681)	0	0
4074025	PPA RIDER Over/Under	226,821	0	226,821	0
	DDA Regulatory Credits	**186,139**	**(40,681)**	**226,821**	**-**
	Amortization	**957,776**	**348,994**	**484,742**	**124,039**
4030001	Depreciation Exp	9,172,426	3,896,028	3,061,626	2,214,772
4030029	Over/Undr Depr Exp Var Riders	1,604,053	0	1,604,053	0
	DDA Depreciation	**10,776,479**	**3,896,028**	**4,665,679**	**2,214,772**
	DDA STP Nuclear Decommissioning	**-**	**-**	**-**	**-**
4031001	Depr - Asset Retirement Oblig	159,200	856	158,345	0
	DDA Asset Retirement Obligation	**159,200**	**856**	**158,345**	**-**
	DDA Removal Costs	**-**	**-**	**-**	**-**
	Depreciation	**10,935,680**	**3,896,884**	**4,824,024**	**2,214,772**
	Depreciation and Amortization	**11,893,455**	**4,245,878**	**5,308,766**	**2,338,812**
	Franchise Taxes	**-**	**-**	**-**	**-**
408100625	State Gross Receipts Tax	1,541	0	1,541	0

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	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025
	Revenue-kWhr Taxes	**1,541**	**-**	**1,541**	**-**
4081002	FICA	316,299	225,294	89,259	1,746
4081003	Federal Unemployment Tax	13,873	9,395	4,351	127
4081007	State Unemployment Tax	19,496	8,002	11,428	66
4081033	Fringe Benefit Loading - FICA	(93,327)	(76,028)	(15,993)	(1,305)
4081034	Fringe Benefit Loading - FUT	(418)	(360)	(50)	(8)
4081035	Fringe Benefit Loading - SUT	(468)	(288)	(180)	0
	Payroll Taxes	**255,455**	**166,015**	**88,814**	**626**
408102023	State Business Occup Taxes	(84,375)	0	(84,375)	0
408102024	State Business Occup Taxes	(550,825)	0	(550,825)	0
408102025	State Business Occup Taxes	587,156	0	587,156	0
	Capacity Taxes	**(48,043)**	**-**	**(48,043)**	**-**
408100523	Real Personal Property Taxes	262,522	0	262,522	0
408100524	Real Personal Property Taxes	1,248,700	706,444	121,347	420,909
408102925	Real-Pers Prop Tax-Cap Leases	55,192	52,134	1,760	1,298
408103625	Real Prop Tax-Cap Leases	1,250	1,250	0	0
408200524	Real Personal Property Taxes	23,842	1,242	5,903	16,697
	Property Taxes	**1,591,506**	**761,070**	**391,532**	**438,904**
	Regulatory Fees	**-**	**-**	**-**	**-**
408101424	Federal Excise Taxes	1,073	0	1,073	0
	Production Taxes	**1,073**	**-**	**1,073**	**-**
408101924	State Sales and Use Taxes	4,877	1,795	3,083	0
	Miscellaneous Taxes	**4,877**	**1,795**	**3,083**	**-**
	Other Non-Income Taxes	**5,951**	**1,795**	**4,156**	**-**
	Taxes Other Than Income Taxes	**1,806,410**	**928,879**	**438,000**	**439,530**
	TOTAL OPERATING EXPENSES	**36,473,274**	**24,809,188**	**17,563,342**	**3,826,533**
	Memo: SEC Total Operating Expenses	**67,727,911**	**72,618,305**	**48,817,979**	**3,826,534**
	OPERATING INCOME	**14,259,114**	**4,046,385**	**(5,002,342)**	**15,213,059**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	13,999	291	13,708	0
	Interest & Dividend NonAffiliated	**13,999**	**291**	**13,708**	**-**
4190005	Interest Income - Assoc CBP	137	137	0	0
	Interest & Dividend Affiliated	**137**	**137**	**-**	**-**
	Total Interest & Dividend Income	**14,137**	**428**	**13,708**	**-**
	Interest & Dividend Carrying Charge	**-**	**-**	**-**	**-**
	Memo: Total Interest & Dividend Income w/ Carrying	**14,137**	**428**	**13,708**	**-**
9260042	SERP Pension - Non-Service	(535)	(499)	(36)	0
9260043	OPEB - Non-Service	242,649	102,164	135,742	4,743
9260062	Pension Plan - Non-Service	213,326	19,814	201,511	(7,999)
9260064	Def AEPSC Pension Settlement	(476)	(184)	(292)	0
	Other Components of Net Periodic Pension	**454,964**	**121,295**	**336,925**	**(3,256)**

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IS8016 YTD Jan 2025 02/16/2025 19:05	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025
4191000	Allw Oth Fnds Usd Drng Cnstr	(32,019)	(5,353)	(167)	(26,498)
	AFUDC	**(32,019)**	**(5,353)**	**(167)**	**(26,498)**
	Gain on Disposition of Equity Investments	**-**	**-**	**-**	**-**
	Interest LTD FMB	**-**	**-**	**-**	**-**
4270002	Int on LTD - Install Pur Contr	(254,583)	(254,583)	0	0
	Interest LTD IPC	**(254,583)**	**(254,583)**	**-**	**-**
	Interest LTD Notes Payable - Affiliated	**-**	**-**	**-**	**-**
	Interest LTD Notes Payable - NonAffiliated	**-**	**-**	**-**	**-**
	Interest LTD Debentures	**-**	**-**	**-**	**-**
4270006	Int on LTD - Sen Unsec Notes	(4,627,854)	(4,627,854)	0	0
	Interest LTD Senior Unsecured	**(4,627,854)**	**(4,627,854)**	**-**	**-**
	Interest LTD Other - Affil	**-**	**-**	**-**	**-**
4270005	Int on LTD - Other LTD	(1,359,596)	(1,359,596)	0	0
	Interest LTD Other - NonAffil	**(1,359,596)**	**(1,359,596)**	**-**	**-**
	Interest on Long-Term Debt	**(6,242,034)**	**(6,242,034)**	**-**	**-**
4300003	Int to Assoc Co - CBP	(225,246)	3,060,354	(4,354,135)	1,068,535
	Interest STD - Affil	**(225,246)**	**3,060,354**	**(4,354,135)**	**1,068,535**
4310007	Lines Of Credit	(69,289)	(20,238)	(36,413)	(12,638)
	Interest STD - NonAffil	**(69,289)**	**(20,238)**	**(36,413)**	**(12,638)**
	Interest on Short Term Debt	**(294,534)**	**3,040,116**	**(4,390,548)**	**1,055,898**
4280002	Amrtz Debt Dscnt&Exp-Instl Pur	(14,382)	(14,382)	0	0
4280003	Amrtz Debt Dscnt&Exp-N/P	(1,790)	(1,790)	0	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	(47,679)	(47,679)	0	0
	Amort of Debt Disc. Prem & Exp	**(63,851)**	**(63,851)**	**-**	**-**
4281004	Amrtz Loss Rcquired Debt-Dbnt	(2,804)	(2,804)	0	0
	Amort Loss on Reacquired Debt	**(2,804)**	**(2,804)**	**-**	**-**
	Amort Gain on Reacquired Debt	**-**	**-**	**-**	**-**
	Other Interest - Fuel Recovery	**-**	**-**	**-**	**-**
4310001	Other Interest Expense	1,131,229	1,722	1,128,297	1,210
4310002	Interest on Customer Deposits	(134,616)	(134,616)	0	0
9310005	Int on Regulated Fin Leases	(2,013)	0	0	0
	Other Interest - NonAffil	**994,600**	**(132,893)**	**1,128,297**	**1,210**
	Other Interest Expense - Affil	**-**	**-**	**-**	**-**
	Interest Rate Hedge Unrealized (Gain)/Loss	**-**	**-**	**-**	**-**
4320000	Allw Brrwed Fnds Used Cnstr-Cr	257,254	92,434	21,662	143,157
	AFUDC-Borrowed Funds	**257,254**	**92,434**	**21,662**	**143,157**
	Total Interest Charges	**(5,351,369)**	**(3,309,032)**	**(3,240,589)**	**1,200,265**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**9,344,827**	**853,723**	**(7,892,465)**	**16,383,570**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	393,132	(215,970)	(2,388,303)	2,997,405
4092001	Inc Tax, Oth Inc&Ded-Federal	(25,926)	(21,737)	1,351	(5,541)
	Federal Current Income Tax	**367,206**	**(237,708)**	**(2,386,951)**	**2,991,865**
4101001	Prov Def I/T Util Op Inc-Fed	3,417,659	899,536	1,983,667	534,457
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(2,093,569)	(486,785)	(1,417,145)	(189,639)

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IS8016 YTD Jan 2025 02/16/2025 19:05	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025
	Federal Deferred Income Tax	1,324,090	412,751	566,522	344,818
	Federal Investment Tax Credits	-	-	-	-
	Federal Income Taxes	1,691,296	175,043	(1,820,430)	3,336,683
4091002	Income Taxes, UOI - State	81,387	(85,191)	(569,370)	735,949
4092002	Inc Tax, Oth Inc & Ded - State	(6,511)	(5,459)	339	(1,391)
	State Current Income Tax	74,876	(90,651)	(569,031)	734,557
	State Deferred Income Tax	-	-	-	-
	State Investment Tax Credits	-	-	-	-
	State Income Taxes	74,876	(90,651)	(569,031)	734,557
	Local Current Income Tax	-	-	-	-
	Local Deferred Income Tax	-	-	-	-
	Local Investment Tax Credits	-	-	-	-
	Local Income Taxes	-	-	-	-
	Foreign Current Income Tax	-	-	-	-
	Foreign Deferred Income Tax	-	-	-	-
	Foreign Investment Tax Credits	-	-	-	-
	Foreign Income Taxes	-	-	-	-
	Total Income Taxes	1,766,172	84,393	(2,389,461)	4,071,240
	Equity Earnings of Subs	-	-	-	-
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	7,578,655	769,330	(5,503,005)	12,312,330
	Discontinued Operations (Net of Taxes)	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-
	NET INCOME	7,578,655	769,330	(5,503,005)	12,312,330
	Minority Interest	-	-	-	-
	Preferred Stock Dividend Subs	-	-	-	-
	Earnings to Common Shareholders	7,578,655	769,330	(5,503,005)	12,312,330
	NET INCOME (LOSS) NODE before PS	7,578,655	769,330	(5,503,005)	12,312,330
	Double Check on Net Income Node after PS	-	(0)	-	(0)

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BS8216 YTD Jan 2025 02/16/2025 19:11	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025
	ASSETS				
	Cash and Cash Equivalents	**1,371,813**	**1,371,813**	**0**	**0**
	Other Cash Deposits	**22,976**	**12,667**	**10,042**	**267**
	Customers	13,436,830	9,708,965	1,168,522	2,559,343
	Accrued Unbilled Revenues	15,101,355	15,101,355	0	0
	Miscellaneous Accounts Receivable	18,231,845	4,473,736	77,258,505	24,274,185
	Allowances for Uncollectible Accounts	(655)	(655)	0	0
	Accounts Receivable	**46,769,375**	**29,283,401**	**78,427,027**	**26,833,528**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**77,442,346**	**6,359,558**	**67,823,023**	**3,259,765**
	Risk Management Contracts - Current	**4,842,619**	**0**	**4,842,619**	**0**
	Margin Deposits	**4,084,629**	**8,151**	**4,076,478**	**0**
	Unrecovered Fuel - Current	**13,757,899**	**0**	**13,757,899**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**2,079,577**	**1,610,870**	**316,412**	**152,294**
	TOTAL CURRENT ASSETS	**150,371,234**	**38,646,460**	**169,253,501**	**30,245,854**
	Electric Production	**1,291,307,281**	**1,335,775,467**	**1,325,435,947**	**958,767,297**
	Electric Transmission	**954,042,094**	**0**	**0**	**0**
	Electric Distribution	**1,199,912,467**	**0**	**0**	**0**
	General Property, Plant and Equipment	**175,874,403**	**83,276**	**(45,138)**	**1,119,396**
	Construction Work-in-Progress	**120,592,600**	**47,257,511**	**6,711,235**	**66,623,855**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,741,728,845**	**1,383,116,254**	**1,332,102,044**	**1,026,510,548**
	less: Accumulated Depreciation and Amortization	**(1,261,416,041)**	**(334,762,553)**	**(657,636,003)**	**(269,017,485)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,480,312,805**	**1,048,353,700**	**674,466,041**	**757,493,063**
	Net Regulatory Assets	**606,976,026**	**140,571,805**	**456,354,529**	**10,049,692**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**325,653**	**0**	**325,653**	**0**
	Employee Benefits and Pension Assets	**38,548,296**	**17,317,588**	**20,426,320**	**804,388**
	Other Non Current Assets	**43,701,450**	**14,265,795**	**24,227,476**	**5,208,179**
	TOTAL OTHER NON-CURRENT ASSETS	**689,551,425**	**172,155,188**	**501,333,977**	**16,062,259**
	TOTAL ASSETS	**3,320,235,463**	**1,259,155,348**	**1,345,053,519**	**803,801,177**
	LIABILITIES				
	Accounts Payable	**114,293,192**	**119,598,954**	**67,464,631**	**15,004,187**
	Advances from Affiliates	**19,007,281**	**(786,356,256)**	**1,073,104,634**	**(267,741,098)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**150,000,000**	**150,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	929,456	4,680	924,776	0
2440021	S/T Liability MTM Collateral	(453,561)	(4,680)	(448,881)	0
	Risk Management Liabilities - MTM	475,895	0	475,895	0
	Risk Management Liabilities	**475,895**	**0**	**475,895**	**0**
	Accrued Taxes	**43,547,884**	**614,224**	**(26,468,972)**	**69,402,633**

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	BALANCE SHEET	Kentucky Power Int Consol	Kentucky Power Company - Distribution	Kentucky Power Company - Generation	Kentucky Power Company - Transmission
		BS8216	110	117	180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025
	Memo: Property Taxes	39,611,242	19,869,456	7,875,183	11,866,604
	Accrued Interest	**14,295,215**	**14,295,215**	**0**	**0**
	Risk Management Collateral	496,705	0	496,705	0
	Utility Customer Deposits	37,876,858	37,876,858	0	0
	Deposits - Customer and Collateral	**38,373,562**	**37,876,858**	**496,705**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	141,975	63,719	78,256	0
	Obligations under Operating Leases - Current	390,595	250,046	63,551	76,998
	Tax Collections Payable	2,741,304	2,741,304	0	0
	Revenue Refunds - Accrued	355,300	0	126,695	228,605
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	878,422	768,351	100,834	9,238
	Accrued Rents	(5,879)	(5,879)	0	0
	Accrued ICP	1,961,644	1,800,161	152,891	8,592
	Accrued Vacations	2,306,653	2,055,998	230,855	19,800
	Misc Employee Benefits	965,864	805,713	160,280	(128)
	Payroll Deductions	101,867	90,321	10,268	1,278
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	173,824	173,664	160	0
2530022	Customer Advance Receipts	1,929,578	1,929,578	0	0
	Customer Advance	1,929,578	1,929,578	0	0
2420511	Control Cash Disburse Account	2,306,348	2,306,348	0	0
	Control Cash Disbursement Account	2,306,348	2,306,348	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	163,541	0	163,541	0
2300002	ARO - Current	3,620,144	0	3,620,144	0
2420083	Active Med and Dental IBNR	87,492	78,138	8,232	1,122
2420088	Econ. Development Fund Curr	637,115	637,115	0	0
2420512	Unclaimed Funds	16,001	16,001	0	0
2420542	Acc Cash Franchise Req	83,561	83,561	0	0
242059225	Sales Use Tax - Leased Equip	30	0	0	30
2420643	Accrued Audit Fees	23,502	13,679	6,036	3,787
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	61,311	61,137	0	174
2530112	Other Deferred Credits-Curr	66,510	66,510	0	0
2530124	Contr In Aid of Constr Advance	447,739	447,739	0	0
	Misc Current and Accrued Liabilities	5,207,630	1,404,564	3,797,953	5,113
	Current Other and Accrued Liabilities	18,922,558	14,070,124	4,579,937	272,498
	Other Current Liabilities	**19,455,128**	**14,383,889**	**4,721,744**	**349,495**
	TOTAL CURRENT LIABILITIES	**399,448,157**	**(449,587,116)**	**1,119,794,637**	**(182,984,783)**
	Long-Term Debt - Affiliated	**0**	**0**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,211,139,131**	**1,211,139,131**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(587,344)**	**(587,344)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,210,551,787*	*1,210,551,787*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	7,742	0	7,742	0
	Long-Term Risk Management Liabilities - MTM	7,742	0	7,742	0

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BS8216 YTD Jan 2025 02/16/2025 19:11	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025	YTD Jan 2025
	Long-Term Risk Management Liabilities	**7,742**	**0**	**7,742**	**0**
	Deferred Income Taxes	**485,858,568**	**168,783,330**	**221,904,580**	**95,170,658**
	Deferred Investment Tax Credits	**0**	**0**	**0**	**0**
	Regulatory Liabilities and Deferred Credits	**118,054,508**	**89,663,452**	**(4,604,356)**	**32,995,412**
	Memo - Reg Liab and Def ITC	*118,054,508*	*89,663,452*	*(4,604,356)*	*32,995,412*
	Asset Retirement Obligation	**85,569,545**	**219,475**	**85,350,069**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**8,932,771**	**14,027,354**	**(6,870,952)**	**1,776,369**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redemp	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	839,358	689,937	149,421	0
	Obligations Under Operating Leases	2,467,932	2,000,742	173,763	293,427
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	101,503	101,503	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	24,509	24,509	0	0
2530185	O\U Accounting of ExpensesT	3,978	0	3,978	0
2530188	Long Term Assoc AP	8,291,746	0	0	8,291,746
2530190	QUAL OF SVC PENALTIES - LT	72,870	0	0	72,870
	Def Credits - Other	8,393,103	24,509	3,978	8,364,616
	Total Other Deferred Credits	8,494,606	126,012	3,978	8,364,616
	Accumulated Provisions - Rate Refund	1,516,357	0	0	1,516,357
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**13,318,253**	**2,816,691**	**327,162**	**10,174,400**
	TOTAL NON-CURRENT LIABILITIES	**1,922,293,175**	**1,486,062,089**	**296,114,246**	**140,116,840**
	TOTAL LIABILITIES	**2,321,741,332**	**1,036,474,973**	**1,415,908,883**	**(42,867,943)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,069,518**	**106,025,371**	**335,469,573**	**84,574,574**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**421,974,613**	**94,250,955**	**(416,612,540)**	**744,336,198**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**998,494,131**	**222,680,376**	**(70,855,364)**	**846,669,120**
	Memo: Total Equity	998,494,131	222,680,376	(70,855,364)	846,669,120
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,320,235,463**	**1,259,155,348**	**1,345,053,519**	**803,801,177**
	out-of-balance	(0)	0	0	(0)

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BS8216 YTD Jan 2024 02/22/2024 08:18	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jan 2024	YTD Jan 2024	YTD Jan 2024	YTD Jan 2024
	ASSETS				
	Cash and Cash Equivalents	**1,152,339**	**1,152,339**	**0**	**0**
	Other Cash Deposits	**55,764**	**22,325**	**32,470**	**969**
	Customers	18,519,473	16,949,245	699,942	870,286
	Accrued Unbilled Revenues	7,013,075	7,013,075	0	0
	Miscellaneous Accounts Receivable	17,053,385	5,183,238	61,130,761	19,078,476
	Allowances for Uncollectible Accounts	(393)	(352)	(1)	(40)
	Accounts Receivable	**42,585,540**	**29,145,206**	**61,830,701**	**19,948,723**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**102,594,181**	**7,622,186**	**91,993,677**	**2,978,318**
	Risk Management Contracts - Current	**3,073,344**	**9,831**	**3,063,513**	**0**
	Margin Deposits	**263,265**	**23,037**	**240,228**	**0**
	Unrecovered Fuel - Current	**13,594,543**	**0**	**13,594,543**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**14,353,273**	**13,927,827**	**290,642**	**134,803**
	TOTAL CURRENT ASSETS	**177,672,248**	**51,902,752**	**171,045,773**	**23,062,813**
	Electric Production	**1,240,433,686**	**1,260,273,268**	**1,278,026,607**	**843,638,255**
	Electric Transmission	**839,247,996**	**0**	**0**	**0**
	Electric Distribution	**1,127,481,153**	**0**	**0**	**0**
	General Property, Plant and Equipment	**175,932,829**	**83,276**	**(45,138)**	**1,119,396**
	Construction Work-in-Progress	**160,319,552**	**54,800,257**	**24,510,858**	**81,008,436**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,543,415,216**	**1,315,156,801**	**1,302,492,328**	**925,766,087**
	less: Accumulated Depreciation and Amortization	**(1,209,528,866)**	**(320,989,216)**	**(631,887,766)**	**(256,651,884)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,333,886,351**	**994,167,585**	**670,604,561**	**669,114,204**
	Net Regulatory Assets	**547,795,819**	**128,477,375**	**411,458,828**	**7,859,617**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Assets	**24,926,812**	**13,254,987**	**10,929,686**	**742,139**
	Other Non Current Assets	**50,653,331**	**15,291,414**	**27,617,576**	**7,744,341**
	TOTAL OTHER NON-CURRENT ASSETS	**623,375,963**	**157,023,776**	**450,006,090**	**16,346,097**
	TOTAL ASSETS	**3,134,934,561**	**1,203,094,114**	**1,291,656,424**	**708,523,113**
	LIABILITIES				
	Accounts Payable	**79,438,538**	**84,328,520**	**51,720,730**	**11,728,378**
	Advances from Affiliates	**48,525,741**	**(763,867,277)**	**1,015,052,183**	**(202,659,164)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**215,000,000**	**215,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	7,952,429	4,764	7,947,665	0
2440021	S/T Liability MTM Collateral	(519,482)	(4,764)	(514,718)	0
	Risk Management Liabilities - MTM	7,432,947	0	7,432,947	0
	Risk Management Liabilities	**7,432,947**	**0**	**7,432,947**	**0**
	Accrued Taxes	**48,921,836**	**13,969,224**	**(5,888,041)**	**40,840,653**
	Memo: Property Taxes	45,385,583	22,582,450	7,980,919	14,822,215
	Accrued Interest	**14,935,371**	**14,935,371**	**0**	**0**

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BS8216 YTD Jan 2024 02/22/2024 08:18	BALANCE SHEET	Kentucky Power Int Consol	Kentucky Power Company - Distribution	Kentucky Power Company - Generation	Kentucky Power Company - Transmission
		BS8216	110	117	180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jan 2024	YTD Jan 2024	YTD Jan 2024	YTD Jan 2024
	Risk Management Collateral	500,098	0	500,098	0
	Utility Customer Deposits	37,603,179	37,603,179	0	0
	Deposits - Customer and Collateral	**38,103,277**	**37,603,179**	**500,098**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	107,892	30,935	76,957	0
	Obligations under Operating Leases - Current	207,492	146,162	59,435	1,895
	Tax Collections Payable	2,301,325	2,301,325	0	0
	Revenue Refunds - Accrued	566,685	0	131,555	435,130
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	810,492	718,629	84,565	7,298
	Accrued Rents	2,009	2,009	0	0
	Accrued ICP	1,723,372	1,610,654	106,944	5,775
	Accrued Vacations	2,565,080	2,296,443	251,345	17,292
	Misc Employee Benefits	1,412,423	677,430	735,029	(36)
	Payroll Deductions	118,211	93,699	23,248	1,264
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	242,169	217,353	24,816	0
2530022	Customer Advance Receipts	4,402,352	4,402,352	0	0
	Customer Advance	4,402,352	4,402,352	0	0
2420511	Control Cash Disburse Account	4,636,503	4,636,503	0	0
	Control Cash Disbursement Account	4,636,503	4,636,503	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	118,665	0	118,665	0
2300002	ARO - Current	205,678	0	205,678	0
2420000	Misc Current & Accrued Liab	12,000,000	12,000,000	0	0
2420088	Econ. Development Fund Curr	585,184	585,184	0	0
2420512	Unclaimed Funds	17,983	17,983	0	0
2420542	Acc Cash Franchise Req	74,906	74,906	0	0
2420643	Accrued Audit Fees	33,022	13,783	12,563	6,676
2420656	Federal Mitigation Accru (NSR)	244,045	0	244,045	0
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	81,124	80,919	0	205
2530112	Other Deferred Credits-Curr	187,792	186,425	0	1,367
2530124	Contr In Aid of Constr Advance	174,268	174,268	0	0
2530177	Deferred Rev-Bonus Lease Curr	3,795	0	3,795	0
	Misc Current and Accrued Liabilities	13,727,145	13,134,153	584,745	8,247
	Current Other and Accrued Liabilities	32,507,766	30,090,548	1,942,247	474,971
	Other Current Liabilities	**32,823,150**	**30,267,646**	**2,078,638**	**476,865**
	TOTAL CURRENT LIABILITIES	**485,180,860**	**(367,763,337)**	**1,070,896,555**	**(149,613,268)**
	Long-Term Debt - Affiliated	**25,000,000**	**25,000,000**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,060,525,767**	**1,060,525,767**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(654,469)**	**(654,469)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,059,871,298*	*1,059,871,298*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	1,264,277	0	1,264,277	0
2440022	L/T Liability MTM Collateral	(59,122)	0	(59,122)	0
	Long-Term Risk Management Liabilities - MTM	1,205,155	0	1,205,155	0
	Long-Term Risk Management Liabilities	**1,205,155**	**0**	**1,205,155**	**0**
	Deferred Income Taxes	**472,602,117**	**163,234,890**	**219,847,382**	**89,519,845**

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BS8216 YTD Jan 2024 02/22/2024 08:18	BALANCE SHEET	Kentucky Power Int Consol	Kentucky Power Company - Distribution	Kentucky Power Company - Generation	Kentucky Power Company - Transmission
		BS8216	110	117	180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Jan 2024	YTD Jan 2024	YTD Jan 2024	YTD Jan 2024
	Deferred Investment Tax Credits	**(0)**	**0**	**(0)**	**0**
	Regulatory Liabilities and Deferred Credits	**100,722,992**	**72,660,156**	**(1,391,833)**	**29,454,668**
	Memo - Reg Liab and Def ITC	*100,722,991*	*72,660,156*	*(1,391,833)*	*29,454,668*
	Asset Retirement Obligation	**18,111,938**	**202,660**	**17,909,278**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**9,494,671**	**11,111,443**	**(3,330,694)**	**1,713,922**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redemption	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	672,901	467,817	205,084	0
	Obligations Under Operating Leases	1,015,165	794,283	220,882	0
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	94,091	94,091	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	39,200	39,200	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	888	0	0	888
2530185	O\U Accounting of ExpensesT	7,793	0	7,793	0
2530188	Long Term Assoc AP	4,099,784	0	0	4,099,784
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	4,232,281	39,200	7,793	4,185,288
	Total Other Deferred Credits	4,326,371	133,291	7,793	4,185,288
	Accumulated Provisions - Rate Refund	845,101	0	0	845,101
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**6,859,539**	**1,395,391**	**433,760**	**5,030,389**
	TOTAL NON-CURRENT LIABILITIES	**1,693,867,709**	**1,333,475,838**	**234,673,048**	**125,718,823**
	TOTAL LIABILITIES	**2,179,048,569**	**965,712,501**	**1,305,569,602**	**(23,894,444)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,771,323**	**106,025,371**	**336,070,072**	**84,675,880**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**378,664,669**	**108,952,193**	**(360,270,853)**	**629,983,330**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**955,885,992**	**237,381,613**	**(13,913,178)**	**732,417,558**
	Memo: Total Equity	955,885,992	237,381,613	(13,913,178)	732,417,558
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,134,934,561**	**1,203,094,114**	**1,291,656,424**	**708,523,113**
	out-of-balance	(0)	0	0	(0)

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KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - January, 2025

Final

GLR7210 02/11/25 15:02

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,324,153,881.22	922,611.38	(240,723.77)	0.00	0.00	1,324,835,768.83
101/106	CLOUD GENERATION	446,948.71	13,038.75	0.00	0.00	0.00	459,987.46
	TOTAL PRODUCTION	**1,324,600,829.93**	**935,650.13**	**(240,723.77)**	**0.00**	**0.00**	**1,325,295,756.29**
101/106	TRANSMISSION	955,494,282.91	3,913,685.55	(640,671.21)	0.00	0.00	958,767,297.25
101/106	CLOUD TRANSMISSION	302,831.60	18,080.78	0.00	0.00	0.00	320,912.38
101/106	DISTRIBUTION	1,328,226,510.37	6,794,615.79	(856,945.60)	0.00	0.00	1,334,164,180.56
101/106	CLOUD DISTRIBUTION	2,053,474.66	61,998.56	0.00	0.00	0.00	2,115,473.22
	TOTAL (ACCOUNTS 101 & 106)	**3,610,677,929.47**	**11,724,030.81**	**(1,738,340.58)**	**0.00**	**0.00**	**3,620,663,619.70**
1011001/12	CAPITAL LEASES	1,329,493.17	0.00	0.00	80,299.89	0.00	1,409,793.06
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**3,612,007,422.64**	**11,724,030.81**	**(1,738,340.58)**	**80,299.89**	**0.00**	**3,622,073,412.76**
1050001	PLANT HELD FOR FUTURE USE	801,671.21	0.00	0.00	0.00	0.00	801,671.21
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEGINNING BALANCE	115,771,812.73					
107000X	ADDITIONS		16,451,700.36				
107000X	TRANSFERS		(11,630,912.72)				
107000X	ENDING BALANCE		4,820,787.64				120,592,600.37
107000X	**CLOUD CONSTRUCTION WIP:**						
107000X	BEGINNING BALANCE	1,813,515.61					
107000X	ADDITIONS		120,748.32				
107000X	TRANSFERS		(93,118.09)				
107000X	ENDING BALANCE		27,630.23				1,841,145.84
	TOTAL ELECTRIC UTILITY PLANT	**3,730,394,422.19**	**16,572,448.68**	**(1,738,340.58)**	**80,299.89**	**0.00**	**3,745,308,830.18**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	502,365.72	0.00	0.00	0.00	0.00	502,365.72
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1210003	NONUTILITY PROPERTY-WIP						
	BEGINNING BALANCE	0.00					
	ADDITIONS		0.00				
	TRANSFERS		0.00				
	ENDING BALANCE		0.00				0.00
1210016	NONUTILITY PROPERTY-CCNC	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	655,168.37	0.00	0.00	0.00	0.00	655,168.37
	TOTAL NONUTILITY PLANT	**1,157,534.09**	**0.00**	**0.00**	**0.00**	**0.00**	**1,157,534.09**

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KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - January, 2025

Final

GLR7410 02/11/25 14:58

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
.	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	640,384,146.97	3,219,970.53	(240,723.77)	(147,719.93)	0.00	643,215,673.80
1080001/11	TRANSMISSION	302,596,611.20	2,214,772.42	(640,671.21)	(1,582,751.30)	0.00	302,587,961.11
1080001/11	DISTRIBUTION	407,529,530.89	3,896,883.78	(856,945.60)	(139,913.86)	0.00	410,429,555.21
1080013	PRODUCTION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	0.00	0.00	0.00	0.00	0.00	0.00
	RETIREMENT WORK IN PROGRESS	(14,227,110.14)	0.00	0.00	(993,637.94)	1,870,385.09	(13,350,362.99)
	TOTAL (108X accounts)	**1,336,283,178.93**	**9,331,626.73**	**(1,738,340.58)**	**(2,864,023.03)**	**1,870,385.09**	**1,342,882,827.14**
	NUCLEAR					0.00	
1110001	PRODUCTION	11,897,023.95	256,485.02	0.00	0.00	0.00	12,153,508.97
1110007	CLOUD IMPLEMENT COST PRODUCTI	185,158.67	7,449.15	0.00	0.00	0.00	192,607.82
1110001	TRANSMISSION	4,426,015.33	127,811.32	0.00	0.00	0.00	4,553,826.65
1110007	CLOUD IMPLEMENT COST TRANSMIS	86,385.47	5,047.19	0.00	0.00	0.00	91,432.66
1110001	DISTRIBUTION	14,844,619.51	399,905.33	0.00	0.00	0.00	15,244,524.84
1110007	CLOUD IMPLEMENT COST DISTRIBUT	732,931.68	29,933.90	0.00	0.00	0.00	762,865.58
	TOTAL (111X accounts)	**32,172,134.61**	**826,631.91**	**0.00**	**0.00**	**0.00**	**32,998,766.52**
1011006	CAPITAL LEASES	414,736.20	0.00	0.00	0.00	10,788.68	425,524.88
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**1,368,870,049.74**	**10,158,258.64**	**(1,738,340.58)**	**(2,864,023.03)**	**1,881,173.77**	**1,376,307,118.54**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	179,574.02	555.81	0.00	0.00	0.00	180,129.83
1220002	Depr&Amrt of Nonutl Prop-Leasd	0.00	0.00	0.00	0.00	0.00	0.00
1220003	Depr&Amrt of Nonutl Prop-WIP	0.00	0.00	0.00	0.00	0.00	0.00
1220004	Depletion - Owned	0.00	0.00	0.00	0.00	0.00	0.00
1240027	Other Property - RWIP	35,121.36	0.00	0.00	0.00	0.00	35,121.36
1240028	Other Property - Retirement	(46,947.27)	0.00	0.00	0.00	0.00	(46,947.27)
	TOTAL NONUTILITY PLANT	**167,748.11**	**555.81**	**0.00**	**0.00**	**0.00**	**168,303.92**

U.S. Department of Energy Energy Information Administration Form EIA-826	**Monthly Electric Utility Sales and Revenue Report with State Distributions – 2025**	Form Approval OMB NO.1905-0129 (Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**

Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650.

Utility Name: Kentucky Power Company **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan_X__ Feb___ Mar___ Apr___ May___ Jun___ Jul___ Aug___ Sep___ Oct___ Nov___ Dec__ , 2025

Contact Person: Sandra Vargo	**Phone number: 614-716-2671**
Email: slvargo@aep.com	**Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	$ 41,148	$ 19,378	$ 14,095	$ -	$ 74,621
	b. Megwatthours	$ 285,553	$ 146,950	$ 167,130	-	$ 599,633
	c. Number of consumers	$ 131,019	$ 30,699	$ 936	-	$ 162,654
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					

Note:

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March 31st, 2025

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed Feb 2025 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:	
1-12	Income Statement
1-3	Details of Operating Revenues
5-10	Operating Expenses – Functional Expenses
12	Detail Statement of Taxes
Balance Sheet:	
13	Balance Sheet – Assets & Other Debits
13-15	Balance Sheet – Liabilities & Other Credits
14-15	Deferred Credits
15	Statement of Retained Earnings
Utility Property:	
16-17	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Digitally signed by Brian J. Frantz
DN: cn=Brian J. Frantz, o=AEP, ou=Corporate Accounting, email=bjfrantz@aep.com
Reason: I have reviewed this document
Date: 2025.03.31 10:58:08 -04'00'

Brian J Frantz
Director - Corporate Accounting

American Electric Power

INCOME STATEMENT

IS8016
YTD Feb 2025
03/08/2025 13:01

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Feb 2025	Kentucky Power Company - Distribution 110 Actual YTD Feb 2025	Kentucky Power Company - Generation 117 Actual YTD Feb 2025	Kentucky Power Company - Transmission 180 Actual YTD Feb 2025
		REVENUES				
4400001		Residential Sales-W/Space Htg	38,583,482	39,220,285	(636,802)	0
4400002		Residential Sales-W/O Space Ht	13,660,182	14,247,513	(587,331)	0
4400005		Residential Fuel Rev	17,525,315	17,525,315	0	0
	A	**Revenue - Residential Sales**	**69,768,979**	**70,993,112**	**(1,224,133)**	**-**
4420001		Commercial Sales	18,056,730	18,651,705	(594,974)	0
4420006		Sales to Pub Auth - Schools	3,016,890	3,016,890	0	0
4420007		Sales to Pub Auth - Ex Schools	3,502,126	3,600,525	(98,399)	0
4420013		Commercial Fuel Rev	9,160,976	9,160,976	0	0
	A	**Revenue - Commercial Sales**	**33,736,721**	**34,430,095**	**(693,373)**	**-**
	B	**Revenue - Industrial Sales - Affiliated**	**-**	**-**	**-**	**-**
4420002		Industrial Sales (Excl Mines)	12,012,228	12,642,501	(630,273)	0
4420004		Ind Sales-NonAffil(Incl Mines)	2,949,566	2,949,566	0	0
4420016		Industrial Fuel Rev	11,863,804	11,863,804	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**26,825,597**	**27,455,871**	**(630,273)**	**-**
		Revenue - Industrial Sales	**26,825,597**	**27,455,871**	**(630,273)**	**-**
	A	**Revenue - Gas Products Sales**	**-**	**-**	**-**	**-**
	A	**Revenue - Gas Transportation & Storage Sales**	**-**	**-**	**-**	**-**
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	**-**	**-**	**-**	**-**
4440000		Public Street/Highway Lighting	319,700	321,717	(2,018)	0
4440002		Public St & Hwy Light Fuel Rev	57,952	57,952	0	0
	A	**Revenue - Other Retail Sales**	**377,652**	**379,669**	**(2,018)**	**-**
	B	**Revenue - Other Retail Sales - Affiliated**	**-**	**-**	**-**	**-**
		Revenue - Retail Sales	**130,708,949**	**133,258,746**	**(2,549,797)**	**-**
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	17,099,219
4561033		PJM NITS Revenue - Affiliated	14,368,152	0	0	14,368,152
4561034		PJM TO Adm. Serv Rev - Aff	35,464	0	0	35,464
4561035		PJM Affiliated Trans NITS Cost	(9,352,997)	0	(9,352,997)	0
4561036		PJM Affiliated Trans TO Cost	(19,759)	0	(19,759)	0
4561059		Affil PJM Trans Enhancmnt Rev	274,679	0	0	274,679
4561060		Affil PJM Trans Enhancmnt Cost	(178,803)	0	(178,803)	0
4561062		PROVISION RTO Cost - Affi	267,967	0	267,967	0
4561063		PROVISION RTO Rev Affiliated	(54,778)	0	0	(54,778)
	B	**Revenue - Transmission-Affiliated**	**5,339,925**	**-**	**(9,283,592)**	**31,722,737**
4470150		Transm. Rev.-Dedic. Whlsl/Muni	(5,918)	0	(419,096)	413,177
4470206		PJM Trans loss credits-OSS	32,368	0	32,368	0
4470209		PJM transm loss charges-OSS	(50,104)	0	(50,104)	0
4561005		PJM Point to Point Trans Svc	529,737	0	529,737	0
4561006		PJM Trans Owner Admin Rev	17,970	0	0	17,970
4561007		PJM Network Integ Trans Svc	1,933,214	0	0	1,933,214
4561019		Oth Elec Rev Trans Non Affil	12,369	0	0	12,369
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	53	0	0	53
4561029		PJM NITS Revenue Whsl Cus-NAff	488,231	0	0	488,231
4561030		PJM TO Serv Rev Whls Cus-NAff	1,205	0	0	1,205
4561045		PJM Non-Aff Gen IPP Rev	3,988	0	0	3,988
4561058		NonAffil PJM Trans Enhncmt Rev	315,408	0	0	315,408
4561061		NAff PJM RTEP Rev for Whsl-FR	9,334	0	0	9,334
4561064		PROVISION RTO Rev WhslCus-NAf	(1,840)	0	0	(1,840)
4561065		PROVISION RTO Rev - NonAff	(8,230)	0	0	(8,230)

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American Electric Power

INCOME STATEMENT

IS8016
YTD Feb 2025
03/08/2025 13:01

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Feb 2025	Kentucky Power Company - Distribution 110 Actual YTD Feb 2025	Kentucky Power Company - Generation 117 Actual YTD Feb 2025	Kentucky Power Company - Transmission 180 Actual YTD Feb 2025
	A	**Revenue - Transmission-NonAffiliated**	**3,277,786**	**-**	**92,906**	**3,184,880**
		Revenue - Transmission	**8,617,711**	**-**	**(9,190,686)**	**34,907,617**
	B	**Revenue - Resale-Affiliated**	**-**	**-**	**-**	**-**
4470027		Whsal/Muni/Pb Ath Fuel Rev	640,657	0	640,657	0
4470033		Whsal/Muni/Pub Auth Base Rev	478,823	0	478,823	0
4470082		Financial Electric Realized	(1,157)	0	(1,157)	0
4470089		PJM Energy Sales Margin	392,368	0	392,368	0
4470098		PJM Oper.Reserve Rev-OSS	(15,865)	0	(15,865)	0
4470099		Capacity Cr. Net Sales	(19,881)	0	(19,881)	0
4470100		PJM FTR Revenue-OSS	36,812	0	36,812	0
4470103		PJM Energy Sales Cost	2,052,361	0	2,052,361	0
4470115		PJM Meter Corrections-OSS	(569)	0	(569)	0
4470116		PJM Meter Corrections-LSE	4,793	0	4,793	0
4470126		PJM Incremental Imp Cong-OSS	(35,252)	0	(35,252)	0
4470175		OSS Sharing Reclass - Retail	1,216,490	0	1,216,490	0
4470176		OSS Sharing Reclass-Reduction	(1,216,490)	0	(1,216,490)	0
4470220		PJM Regulation - OSS	859,773	0	859,773	0
4470221		PJM Spinning Reserve - OSS	30,550	0	30,550	0
5550080		PJM Hourly Net Purch.-FERC	(931,393)	0	(931,393)	0
	A	**Revenue - Resale-NonAffiliated**	**3,492,020**	**-**	**3,492,020**	**-**
	A	**Revenue - Resale-Realized**	**-**	**-**	**-**	**-**
	A	**Revenue - Resale-Risk Mgmt MTM**	**-**	**-**	**-**	**-**
	A	**Revenue - Resale-Risk Mgmt Activities**	**-**	**-**	**-**	**-**
		Revenue - Sales for Resale	**3,492,020**	**-**	**3,492,020**	**-**
4470074		Sale for Resale-Aff-Trnf Price	0	0	86,501,277	0
4540001		Rent From Elect Property - Af	335,636	194,502	0	209,141
	B	**Revenue - Other Ele-Affilliated**	**335,636**	**194,502**	**86,501,277**	**209,141**
4500000		Forfeited Discounts	223,739	223,739	0	0
4510001		Misc Service Rev - Nonaffil	8,676	8,602	0	74
4540002		Rent From Elect Property-NAC	211,503	350	210,678	475
4540005		Rent from Elec Prop-Pole Attch	788,649	787,284	0	1,365
4560007		Oth Elect Rev - DSM Program	69,712	69,712	0	0
5010040		Gas Procuremnt Sales Net	(295,270)	0	(295,270)	0
		Revenue - Other Ele-NonAffilliated	**1,007,008**	**1,089,687**	**(84,592)**	**1,914**
		Revenue - Gas	**-**	**-**	**-**	**-**
		Gain/(Loss) on Allowances	**-**	**-**	**-**	**-**
	A	**Revenue - Other Ele-NonAffilliated**	**1,007,008**	**1,089,687**	**(84,592)**	**1,914**
		Revenue - Other Opr Electric	**1,342,645**	**1,284,189**	**86,416,685**	**211,055**
	D	**Revenue Merchandising & Contract Work**	**-**	**-**	**-**	**-**
	C	**Revenues Non-Utility Operations - Affiliated**	**-**	**-**	**-**	**-**
4170004		Rev from Non-Util Oper NonAfil	54,903	54,903	0	0
	D	**Revenues Non-Utility Operations - NonAffiliated**	**54,903**	**54,903**	**-**	**-**
		Revenues from Non-Utility Operations	**54,903**	**54,903**	**-**	**-**
	C	**Non-Operating Rental Income - Affiliated**	**-**	**-**	**-**	**-**
4180005		Non-Opratng Rntal Inc-Depr	(1,112)	0	0	(1,112)
	D	**Non-Operating Rental Income - NonAffiliated**	**(1,112)**	**-**	**-**	**(1,112)**
		Non-Operating Rental Income	**(1,112)**	**-**	**-**	**(1,112)**
	C	**Non-Operating Misc Income -Affiliated**	**-**	**-**	**-**	**-**

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American Electric Power

IS8016 YTD Feb 2025 03/08/2025 13:01		INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
		Layout: IS8016				
17A V2099-01-01		Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Feb 2025	YTD Feb 2025	YTD Feb 2025	YTD Feb 2025
4210002		Misc Non-Op Inc-NonAsc-Rents	260	0	260	0
4210007		Misc Non-Op Inc - NonAsc - Oth	165	149	16	0
	D	**Non-Operating Misc Income - NonAffiliated**	**425**	**149**	**276**	**-**
		Non-Operating Misc Income	**425**	**149**	**276**	**-**
4560015		Other Electric Revenues - ABD	99,715	99,715	0	0
	D	**Associated Business Development Income**	**99,715**	**99,715**	**-**	**-**
		Revenue - Other Opr - Other	**153,931**	**154,767**	**276**	**(1,112)**
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	**-**	**-**	**-**	**-**
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***153,931***	***154,767***	***276***	***(1,112)***
		Revenue - Other Operating	**1,496,576**	**1,438,956**	**86,416,961**	**209,944**
4491002		Prov Rate Refund-Nonaffiliated	(39,976)	0	0	(39,976)
4491003		Prov Rate Refund - Retail	(9,038)	0	0	(9,038)
	A	**Provision for Rate Refund - NonAffiliated**	**(49,014)**	**-**	**-**	**(49,014)**
4491004		Prov Rate Refund - Affiliated	(267,377)	0	0	(267,377)
	B	**Provision for Rate Refund - Affiliated**	**(267,377)**	**-**	**-**	**(267,377)**
		Provision for Rate Refund	**(316,391)**	**-**	**-**	**(316,391)**
	A	**Revenue - Power Sales**	**-**	**-**	**-**	**-**
		TOTAL OPERATING REVENUES	**143,998,865**	**134,697,702**	**78,168,497**	**34,801,169**
=(A)		*Memo: G/T/D Revenue*	*138,436,749*	*134,348,433*	*950,536*	*3,137,780*
=(B)		*Memo: Other Affiliated Revenue*	*5,408,184*	*194,502*	*77,217,685*	*31,664,501*
=(C)		*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
=(D)		*Memo: Revenue-Oth Opr-Oth Nor*	*153,931*	*154,767*	*276*	*(1,112)*
		Memo: Total Operating Revenues	*143,998,865*	*134,697,702*	*78,168,497*	*34,801,169*
=(E)=(B)+(C)		*Memo: Affiliated Revenue*	***5,408,184***	***194,502***	***77,217,685***	***31,664,501***
=(F)=(D)+(A)		*Memo: Non-Affiliated Revenue*	***138,590,680***	***134,503,200***	***950,812***	***3,136,668***
		Memo: Total Operating Revenues	***143,998,865***	***134,697,702***	***78,168,497***	***34,801,169***
		FUEL EXPENSES				
5010000		Fuel	1,310,557	0	1,310,557	0
5010001		Fuel Consumed	15,754,815	0	15,754,815	0
5010003		Fuel - Procure Unload & Handle	793,653	0	793,653	0
5010012		Ash Sales Proceeds	3,075	0	3,075	0
5010019		Fuel Oil Consumed	439,067	0	439,067	0
5010020		Nat Gas Consumed Steam	9,820,745	0	9,820,745	0
5010021		Transp Gas Consumed Steam	67,073	0	67,073	0
5010027		Gypsum handling/disposal costs	214,990	0	214,990	0
5010028		Gypsum Sales Proceeds	(362,790)	0	(362,790)	0
5010034		Gas Transp Res Fees-Steam	1,063,389	0	1,063,389	0
		Fuel Expense Total	**29,104,575**	**-**	**29,104,575**	**-**
5010005		Fuel - Deferred	(2,371,851)	0	(2,371,851)	0
		Deferred Fuel Expense	**(2,371,851)**	**-**	**(2,371,851)**	**-**
		Over Under Fuel Expense				
		Fuel for Electric Generation	**26,732,724**	**-**	**26,732,724**	**-**
		Fuel from Affiliates for Electric Generation	**-**	**-**	**-**	**-**
5090000		Allow Consum Title IV SO2	5,028	0	5,028	0
5090009		Allow Consumpt CSAPR SO2	25	0	25	0
		Allowances - Consumption	**5,053**	**-**	**5,053**	**-**
5020002		Urea Expense	219,682	0	219,682	0

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INCOME STATEMENT

IS8016
YTD Feb 2025
03/08/2025 13:01

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Feb 2025	Kentucky Power Company - Distribution 110 Actual YTD Feb 2025	Kentucky Power Company - Generation 117 Actual YTD Feb 2025	Kentucky Power Company - Transmission 180 Actual YTD Feb 2025
5020004	Lime-Related Expenses	401,717	0	401,717	0
	Emissions Control - Chemicals	**621,399**	**-**	**621,399**	**-**
	Total Fuel for Electric Generation	**27,359,176**	**-**	**27,359,176**	**-**
	Memo: NonAff Fuel/Allow/Emissions	***27,359,176***	**-**	***27,359,176***	**-**
5550029	Purch Power-Assoc-Trnsfr Price	0	86,501,277	0	0
	Purchased Electricity from AEP - Affiliates	**-**	**86,501,277**	**-**	**-**
5550001	Purch Pwr-NonTrading-Nonassoc	29,714,236	0	29,714,236	0
5550023	Purch Power Capacity -NA	403,097	0	403,097	0
5550039	PJM Inadvertent Mtr Res-OSS	(691)	0	(691)	0
5550040	PJM Inadvertent Mtr Res-LSE	(9,319)	0	(9,319)	0
5550074	PJM Reactive-Charge	559,787	0	559,787	0
5550075	PJM Reactive-Credit	(239,146)	0	(239,146)	0
5550076	PJM Black Start-Charge	50,179	0	50,179	0
5550078	PJM Regulation-Charge	200,186	0	200,186	0
5550079	PJM Regulation-Credit	213,941	0	213,941	0
5550083	PJM Sync & Non Sync-Charge	141,163	0	141,163	0
5550084	PJM Sync & Non Sync-Credit	(8,083)	0	(8,083)	0
5550123	PJM OpRes-LSE-Charge	3,141,494	0	3,141,494	0
5550124	PJM Implicit Congestion-LSE	1,793,692	0	1,793,692	0
5550132	PJM FTR Revenue-LSE	(4,541,694)	0	(4,541,694)	0
5550137	PJM OpRes-LSE-Credit	(13,722)	0	(13,722)	0
5550326	PJM Transm Loss Charges - LSE	2,178,299	0	2,178,299	0
5550327	PJM Transm Loss Credits-LSE	(988,218)	0	(988,218)	0
5550328	PJM FC Penalty Credit	(1,354)	0	(1,354)	0
	Purchased Electricity for Resale - NonAffiliated	**32,593,847**	**-**	**32,593,847**	**0**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**
	Purchased Gas for Resale - NonAffiliated	**-**	**-**	**-**	**-**
	Total Purchased Power	**32,593,847**	**86,501,277**	**32,593,847**	**0**
	GROSS MARGIN	**84,045,842**	**48,196,425**	**18,215,474**	**34,801,169**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	680,615	3,179	675,688	1,748
5020000	Steam Expenses	362,863	0	362,863	0
5050000	Electric Expenses	1,010	0	1,010	0
5060000	Misc Steam Power Expenses	770,197	(19,112)	787,591	1,718
5060002	Misc Steam Power Exp-Assoc	10,129	0	10,129	0
5070006	Rents - Associated	386	0	386	0
	Steam Generation Op Exp	**1,825,202**	**(15,932)**	**1,837,668**	**3,466**
	Nuclear Generation Op Exp	**-**	**-**	**-**	**-**
	Hydro Generation Op Exp	**-**	**-**	**-**	**-**
5560000	Sys Control & Load Dispatching	9,652	0	9,652	0
5570000	Other Expenses	130,398	0	130,398	0
5570007	Other Pwr Exp - Wholesale RECs	243	243	0	0
5581300	Oper Supervision & Engineering	154	29	97	28
5581400	Wind Turb Gen&Oth Plnt Op-Mjr	399	0	399	0
5582000	Solar Panel Gen&Oth Plt Op-Mjr	2	0	2	0
5757000	PJM Admin-MAM&SC- OSS	13,836	0	13,836	0
5757001	PJM Admin-MAM&SC- Internal	307,829	0	307,829	0
	Other Generation Op Exp	**462,513**	**272**	**462,213**	**28**

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INCOME STATEMENT

IS8016
YTD Feb 2025
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Layout: IS8016

17A V2099-01-01 | Account: GL_ACCT_SEC | Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Feb 2025	Kentucky Power Company - Distribution 110 Actual YTD Feb 2025	Kentucky Power Company - Generation 117 Actual YTD Feb 2025	Kentucky Power Company - Transmission 180 Actual YTD Feb 2025
5600000	Oper Supervision & Engineering	419,038	9,827	3,274	405,937
5612000	Load Dispatch-Mntr&Op TransSys	74,936	375	53	74,508
5613000	Load Dispatch-Trans Srvc&Sched	244	0	0	244
5614000	PJM Admin-SSC&DS-OSS	13,766	0	13,766	0
5614001	PJM Admin-SSC&DS-Internal	278,518	0	278,518	0
5615000	Reliability,Plng&Stds Develop	10,494	237	33	10,224
5618000	PJM Admin-RP&SDS-OSS	5,720	0	5,720	0
5618001	PJM Admin-RP&SDS- Internal	104,122	0	104,122	0
5620001	Station Expenses - Nonassoc	42,547	0	0	42,547
5630000	Overhead Line Expenses	1,597	0	0	1,597
5650002	Transmssn Elec by Others-NAC	24,851	0	24,851	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	17,099,219	0	0
5650012	PJM Trans Enhancement Charge	346,559	0	346,559	0
5650015	PJM TO Serv Exp - Aff	33,804	0	33,804	0
5650016	PJM NITS Expense - Affiliated	12,370,955	0	12,370,955	0
5650019	Affil PJM Trans Enhncement Exp	797,701	0	797,701	0
5650020	PROVISION RTO Affl Expense	(234,504)	0	(234,504)	0
5650021	PJM NITS Expense - Non-Affilia	158,995	0	158,995	0
5650023	Amort of PROVISION RTO Expense	1,587,904	0	1,587,904	0
5660000	Misc Transmission Expenses	111,541	(52,218)	378	163,380
5660011	Misc Transm Exp - Affiliate	632	0	0	632
5670002	Rents - Associated	0	0	0	68,007
	Transmission Op Exp	**16,149,419**	**17,057,441**	**15,492,128**	**767,077**
5800000	Oper Supervision & Engineering	232,047	229,573	167	2,318
5810000	Load Dispatching	189	189	0	0
5820000	Station Expenses	63,372	60,841	4	2,526
5830000	Overhead Line Expenses	218,920	219,031	0	(13)
5840000	Underground Line Expenses	66,626	66,630	0	(5)
5850000	Street Lighting & Signal Sys E	2,436	2,438	0	0
5860000	Meter Expenses	201,654	201,829	0	0
5870000	Customer Installations Exp	24,488	24,505	0	2
5880000	Miscellaneous Distribution Exp	316,643	312,540	310	3,955
5890001	Rents - Nonassociated	230,955	230,955	0	0
5890002	Rents - Associated	2,063	2,063	0	0
	Distribution Op Exp	**1,359,392**	**1,350,595**	**481**	**8,783**
9010000	Supervision - Customer Accts	3,777	3,788	(3)	(9)
9020000	Meter Reading Expenses	2,327	2,327	0	0
9020002	Meter Reading - Regular	57,049	57,069	0	0
9020003	Meter Reading - Large Power	5,474	5,474	0	0
9030000	Cust Records & Collection Exp	59,912	58,996	8	908
9030001	Customer Orders & Inquiries	459,052	458,728	96	236
9030002	Manual Billing	1,116	1,116	0	0
9030003	Postage - Customer Bills	106,506	106,506	0	0
9030004	Cashiering	9,269	9,269	0	0
9030005	Collection Agents Fees & Exp	754	754	0	0
9030006	Credit & Oth Collection Activi	46,433	46,449	0	0
9030007	Collectors	46,348	46,348	0	0
9030009	Data Processing	(315)	(315)	0	0
9040007	Uncoll Accts - Misc Receivable	(5,853)	(5,853)	0	0

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INCOME STATEMENT

IS8016
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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Feb 2025	Kentucky Power Company - Distribution 110 Actual YTD Feb 2025	Kentucky Power Company - Generation 117 Actual YTD Feb 2025	Kentucky Power Company - Transmission 180 Actual YTD Feb 2025
9050000	Misc Customer Accounts Exp	7,125	7,125	0	0
9070000	Supervision - Customer Service	3,628	3,625	0	3
9080000	Customer Assistance Expenses	191,677	191,685	0	0
9080004	Cust Assistnce Exp - DSM - Ind	13	13	0	0
9080009	Cust Assistance Expense - DSM	69,316	69,316	0	0
9100000	Misc Cust Svc&Informational Ex	3,269	1,882	692	695
9100001	Misc Cust Svc & Info Exp - RCS	(89)	(48)	0	(42)
	Customer Service and Information Op Exp	**1,066,786**	**1,064,254**	**793**	**1,791**
9120000	Demonstrating & Selling Exp	583	583	0	0
9120003	Demo & Selling Exp - Area Dev	3	3	0	0
	Sales Expenses	**586**	**586**	**-**	**-**
	Memo: Insurance (9240 9250)	**384,408**	**150,246**	**183,570**	**50,591**
9200000	Administrative & Gen Salaries	2,067,448	1,042,368	687,207	337,876
9210001	Off Supl & Exp - Nonassociated	387,136	257,943	104,942	24,277
9210003	Office Supplies & Exp - Trnsf	40	13	18	8
9210021	EMP TRAVEL - Airfare	13	5	6	3
9210022	MEALS & ENT-100 Pct DEDUCTIBLE	29	20	9	0
9210023	EMP TRAVEL-MILEAGE	28	19	9	0
9210024	EMP TRAVEL-PARKING	2	1	0	0
9210025	MEALS & ENT-50 Pct DEDUCTIBLE	8	6	3	0
9210026	EMP TRAVEL-CAR RENTAL	10	7	3	0
9210027	EMP TRAVEL-TAXI AND SHUTTLE	1	0	0	0
9210028	EMP TRAVEL-HOTEL & LODGING	75	38	28	8
9210030	EMP TRAVEL-OTHER	1	0	0	0
9210033	FOOD SERVICE-CATERING	40	13	18	8
9210037	OEM/TECHNICAL TRAINING	100	0	100	0
9210040	DUES-BUSINESS/PROFESSIONAL	81	28	37	17
9210041	VEHICLE-LICENSE FEES	4	1	2	1
9220000	Administrative Exp Trnsf - Cr	(27,277)	(27,152)	0	(124)
9220001	Admin Exp Trnsf to Cnstrction	(71,064)	(71,064)	0	0
9220004	Admin Exp Trnsf to ABD	(114)	(114)	0	0
9220005	Overhead Loadings	(111,096)	(80,805)	(23,002)	(7,288)
9230001	Outside Svcs Empl - Nonassoc	412,044	148,208	160,019	103,817
9230003	AEPSC Billed to Client Co	(362,070)	(125,659)	(127,347)	(109,064)
9230031	SRV-OUTSIDE SERVICES (TECH)	28	10	13	6
9230034	SRV-SOFTWARE LICENSING	1,284	977	295	13
9230064	Def AEPSC Pension Settlement	3,464	1,242	1,108	1,114
9240000	Property Insurance	184,888	47,064	104,947	32,877
9250000	Injuries and Damages	320,616	220,898	82,228	17,490
9250002	Emp Accdent Prvntion-Adm Exp	(95)	(32)	(34)	(29)
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	(79,946)	(77,000)	(3,324)	377
9250007	Prsnal Injries&Prop Dmage-Pub	700	0	700	0
9250010	Frg Ben Loading - Workers Comp	(41,756)	(40,684)	(948)	(124)
9260000	Employee Pensions & Benefits	405	405	0	0
9260002	Pension & Group Ins Admin	4,846	2,231	2,540	75
9260003	Pension Plan	338,984	224,279	111,811	2,893
9260004	Group Life Insurance Premiums	22,600	14,789	7,655	156
9260005	Group Medical Ins Premiums	916,950	637,929	268,350	10,671
9260007	Group L-T Disability Ins Prem	72,368	41,825	30,463	80

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INCOME STATEMENT

IS8016
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Layout: IS8016

17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Feb 2025	Kentucky Power Company - Distribution 110 Actual YTD Feb 2025	Kentucky Power Company - Generation 117 Actual YTD Feb 2025	Kentucky Power Company - Transmission 180 Actual YTD Feb 2025
9260009	Group Dental Insurance Prem	28,328	19,332	8,688	308
9260010	Training Administration Exp	236	116	95	26
9260012	Employee Activities	878	572	305	1
9260021	Postretirement Benefits - OPEB	13,633	7,392	6,056	186
9260027	Savings Plan Contributions	300,390	198,211	99,902	2,276
9260037	Supplemental Pension	1,105	993	112	0
9260050	Frg Ben Loading - Pension	(146,284)	(127,489)	(16,133)	(2,662)
9260051	Frg Ben Loading - Grp Ins	(387,856)	(336,068)	(44,989)	(6,799)
9260052	Frg Ben Loading - Savings	(117,721)	(99,028)	(16,646)	(2,047)
9260053	Frg Ben Loading - OPEB	(7,189)	(5,507)	(1,407)	(276)
9260055	IntercoFringeOffset- Don't Use	(65,598)	(65,598)	0	0
9260058	Frg Ben Loading - Accrual	(95,923)	(94,545)	1,807	(3,185)
9270000	Franchise Requirements	26,728	26,728	0	0
9280000	Regulatory Commission Exp	8,104	3,556	2,329	2,220
9280002	Regulatory Commission Exp-Case	242,268	116,676	59,126	66,467
9280005	Reg Com Exp-FERC Trans Cases	1,736	77	53	1,606
9280006	State Publ Serv CommissionFees	158,866	158,866	0	0
9301000	General Advertising Expenses	5,000	5,000	0	0
9301001	Newspaper Advertising Space	912	405	256	250
9301003	TV Station Advertising Time	829	369	233	228
9301007	Special Adv Space & Prod Exp	750	750	0	0
9301012	Public Opinion Surveys	2,389	2,389	0	0
9301015	Other Corporate Comm Exp	667	667	0	0
9302000	Misc General Expenses	100,913	43,988	29,593	27,331
9302003	Corporate & Fiscal Expenses	16,094	11,745	3,378	971
9310001	Rents - Real Property	800	800	0	0
9310002	Rents - Personal Property	8,467	7,191	1,185	91
	Administration & General	**4,139,296**	**2,095,396**	**1,541,799**	**502,131**
4111005	Accretion Expense	385,530	3,088	382,443	0
	Accretion	**385,530**	**3,088**	**382,443**	**-**
4116000	Gain From Disposition of Plant	(2,756)	(2,756)	0	0
	Loss/(Gain) on Utility Plant	**(2,756)**	**(2,756)**	**-**	**-**
9302006	Assoc Bus Dev - Materials Sold	12,997	12,996	0	2
9302007	Assoc Business Development Exp	45,468	41,643	48	3,782
	Associated Business Development Expenses	**58,465**	**54,639**	**48**	**3,784**
	Gain on Disposition of Property	**-**	**-**	**-**	**-**
	Loss on Disposition of Property	**-**	**-**	**-**	**-**
	Loss(Gain) of Sale of Property	**-**	**-**	**-**	**-**
4265009	Factored Cust A/R Exp - Affil	639,063	639,063	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	200,645	200,645	0	0
	Opr Exp and Factored A/R	**839,708**	**839,708**	**-**	**-**
	Water Heaters	**-**	**-**	**-**	**-**
4030047	Depr Exp - Cloud Computing	43,982	30,967	7,666	5,349
4040007	Cloud Implement - Amort Plant	42,430	29,934	7,449	5,047
4265004	Social & Service Club Dues	665	665	0	0
4265007	Regulatory Expenses	880	390	249	242
	Expense of Non-Utility Operation	**87,958**	**61,956**	**15,364**	**10,638**
4210009	Misc Non-Op Exp - NonAssoc	341	142	89	111

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IS8016 YTD Feb 2025 03/08/2025 13:01	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Feb 2025	YTD Feb 2025	YTD Feb 2025	YTD Feb 2025
	Misc NonOp Expenses - NonAssoc	**341**	**142**	**89**	**111**
4261000	Donations	280,121	279,739	106	275
	Donation Contributions	**280,121**	**279,739**	**106**	**275**
4263001	Penalties	1	1	1	0
	Provision for Penalties	**1**	**1**	**1**	**0**
4264000	Civic and Political Activity	40,036	22,991	8,579	8,468
4264001	Non-deduct Lobbying per IRS	5,085	1,721	2,302	1,062
	Civic & Political Activities	**45,121**	**24,712**	**10,881**	**9,530**
4265002	Other Deductions - Nonassoc	13,998	2,241	1,626	10,131
	Other Deductions	**13,998**	**2,241**	**1,626**	**10,131**
	Shutdown Coal Company Expenses	**-**	**-**	**-**	**-**
	All Other Operational Expenses	**1,267,247**	**1,208,498**	**28,067**	**30,685**
	Operational Expenses	**26,711,682**	**22,816,080**	**19,745,639**	**1,317,745**
5100000	Maint Supv & Engineering	177,834	0	177,833	0
5110000	Maintenance of Structures	278,682	0	278,682	0
5120000	Maintenance of Boiler Plant	2,278,326	0	2,278,326	0
5120034	BSDR O/U Recovery - Maint Cost	(458)	0	(458)	0
5120037	KY Steam Maint O/U	(116,542)	0	(116,542)	0
5130000	Maintenance of Electric Plant	858,296	0	858,296	0
5132000	Maint of Computer Software-Mjr	2,025	0	2,025	0
5133000	Maint of Comm Equipmt-Mjr	310	0	310	0
5140000	Maintenance of Misc Steam Plt	187,597	0	187,597	0
	Steam Generation Maintenance	**3,666,070**	**-**	**3,666,070**	**0**
	Nuclear Generation Maintenance	**-**	**-**	**-**	**-**
	Hydro Generation Maintenance	**-**	**-**	**-**	**-**
5581900	Maint Wind Turb Struct&Eq-Mjr	4	0	4	0
	Other Generation Maintenance	**4**	**-**	**4**	**-**
5680000	Maint Supv & Engineering	1,939	1	146	1,792
5690000	Maintenance of Structures	5,953	0	0	5,953
5691000	Maint of Computer Hardware	1,100	69	27	1,004
5692000	Maint of Computer Software	20,643	0	445	20,198
5693000	Maint of Communication Equip	2,513	1	0	2,512
5700000	Maint of Station Equipment	148,737	7	2	148,727
5710000	Maintenance of Overhead Lines	854,558	0	0	854,558
5720000	Maint of Underground Lines	287	0	0	287
5730000	Maint of Misc Trnsmssion Plt	2,357	0	0	2,357
	Transmission Maintenance	**1,038,087**	**78**	**621**	**1,037,388**
5900000	Maint Supv & Engineering	10,330	10,155	0	177
5910000	Maintenance of Structures	41	0	0	41
5920000	Maint of Station Equipment	99,641	95,506	24	4,112
5923000	Maint of Computer Software-Mjr	22,735	22,735	0	0
5924000	Maint of Comm Equipmt-Mjr	163,035	163,035	0	0
5930000	Maintenance of Overhead Lines	14,959,126	14,960,593	34	695
5930001	Tree and Brush Control	60,970	61,006	0	0
5940000	Maint of Underground Lines	5,235	5,211	0	27
5950000	Maint of Lne Trnf,Rglators&Dvi	847	847	0	0
5960000	Maint of Strt Lghtng & Sgnal S	459	459	0	0
5970000	Maintenance of Meters	5,867	5,871	0	0
5980000	Maint of Misc Distribution Plt	3,952	3,817	1	135

American Electric Power

INCOME STATEMENT

IS8016
YTD Feb 2025
03/08/2025 13:01

Layout: IS8016

17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Feb 2025	Kentucky Power Company - Distribution 110 Actual YTD Feb 2025	Kentucky Power Company - Generation 117 Actual YTD Feb 2025	Kentucky Power Company - Transmission 180 Actual YTD Feb 2025
	Distribution Maintenance	**15,332,236**	**15,329,233**	**59**	**5,187**
9350000	Maintenance of General Plant	737	737	0	0
9350001	Maint of Structures - Owned	38,681	36,787	950	944
9350002	Maint of Structures - Leased	933	720	76	138
9350013	Maint of Cmmncation Eq-Unall	(163)	0	(0)	0
9350015	Maint of Office Furniture & Eq	0	0	0	0
9350024	Maint of DA-AMI Comm Equip	0	0	0	0
9351000	Maint of Computer Hardware	736	565	162	9
9352000	Maint of Computer Software	125,916	46,126	70,397	9,394
9353000	Maint of Comm Equipmt	29,076	23,794	4,968	314
	Administration & General Maintenance	**195,916**	**108,728**	**76,553**	**10,799**
	All Other Maintenance Expenses	**-**	**-**	**-**	**-**
	Maintenance Expenses	**20,232,313**	**15,438,040**	**3,743,306**	**1,053,374**
	Total Operational and Maintenance Expenses	**46,943,995**	**38,254,120**	**23,488,944**	**2,371,119**
4030046	Capitalized Software Depr Exp	786,722	400,330	256,687	129,706
4040001	Amort. of Plant	718,520	379,443	225,247	113,829
4060001	Amort of Plt Acq Adj	6,436	0	0	6,436
	DDA Amortization	**1,511,678**	**779,773**	**481,934**	**249,971**
4073014	Regulatory Debit - BSDR	34,344	0	34,344	0
	DDA Regulatory Debits	**34,344**	**-**	**34,344**	**-**
4074000	Regulatory Credits	(81,362)	(81,362)	0	0
4074025	PPA RIDER Over/Under	949,779	0	949,779	0
	DDA Regulatory Credits	**868,417**	**(81,362)**	**949,779**	**-**
	Amortization	**2,414,439**	**698,411**	**1,466,058**	**249,971**
4030001	Depreciation Exp	18,374,202	7,809,690	6,126,241	4,438,271
4030029	Over/Undr Depr Exp Var Riders	2,930,349	0	2,930,349	0
	DDA Depreciation	**21,304,551**	**7,809,690**	**9,056,590**	**4,438,271**
	DDA STP Nuclear Decommissioning	**-**	**-**	**-**	**-**
4031001	Depr - Asset Retirement Oblig	318,401	1,712	316,689	0
	DDA Asset Retirement Obligation	**318,401**	**1,712**	**316,689**	**-**
	DDA Removal Costs	**-**	**-**	**-**	**-**
	Depreciation	**21,622,952**	**7,811,402**	**9,373,279**	**4,438,271**
	Depreciation and Amortization	**24,037,391**	**8,509,813**	**10,839,337**	**4,688,242**
	Franchise Taxes	**-**	**-**	**-**	**-**
408100624	State Gross Receipts Tax	126	0	0	126
408100625	State Gross Receipts Tax	3,083	0	3,083	0
	Revenue-kWhr Taxes	**3,209**	**-**	**3,083**	**126**
4081002	FICA	582,551	403,786	174,683	4,082
4081003	Federal Unemployment Tax	10,954	6,692	4,122	139
4081007	State Unemployment Tax	20,176	7,090	12,959	128
4081033	Fringe Benefit Loading - FICA	(220,631)	(185,786)	(31,143)	(3,702)
4081034	Fringe Benefit Loading - FUT	(1,131)	(1,001)	(108)	(22)
4081035	Fringe Benefit Loading - SUT	(1,187)	(800)	(387)	0
	Payroll Taxes	**390,732**	**229,981**	**160,127**	**624**
408102023	State Business Occup Taxes	(84,375)	0	(84,375)	0
408102024	State Business Occup Taxes	(550,825)	0	(550,825)	0
408102025	State Business Occup Taxes	1,174,313	0	1,174,313	0

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INCOME STATEMENT

IS8016
YTD Feb 2025
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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Feb 2025	Kentucky Power Company - Distribution 110 Actual YTD Feb 2025	Kentucky Power Company - Generation 117 Actual YTD Feb 2025	Kentucky Power Company - Transmission 180 Actual YTD Feb 2025
	Capacity Taxes	**539,113**	**-**	**539,113**	**-**
408100523	Real Personal Property Taxes	525,044	0	525,044	0
408100524	Real Personal Property Taxes	2,497,400	1,412,888	242,694	841,818
408102925	Real-Pers Prop Tax-Cap Leases	110,384	104,268	3,520	2,596
408103625	Real Prop Tax-Cap Leases	2,500	2,500	0	0
408200524	Real Personal Property Taxes	29,384	1,242	11,445	16,697
	Property Taxes	**3,164,712**	**1,520,898**	**782,703**	**861,111**
	Regulatory Fees	**-**	**-**	**-**	**-**
408101424	Federal Excise Taxes	1,073	0	1,073	0
	Production Taxes	**1,073**	**-**	**1,073**	**-**
408101924	State Sales and Use Taxes	1,795	1,795	0	0
408101925	State Sales and Use Taxes	8,033	1,868	6,166	0
	Miscellaneous Taxes	**9,828**	**3,662**	**6,166**	**-**
	Other Non-Income Taxes	**10,901**	**3,662**	**7,239**	**-**
	Taxes Other Than Income Taxes	**4,108,667**	**1,754,541**	**1,492,265**	**861,861**
	TOTAL OPERATING EXPENSES	**75,090,053**	**48,518,474**	**35,820,546**	**7,921,222**
	Memo: SEC Total Operating Expenses	**135,043,076**	**135,019,751**	**95,773,569**	**7,921,222**
	OPERATING INCOME	**8,955,788**	**(322,049)**	**(17,605,072)**	**26,879,947**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	26,671	587	26,084	0
	Interest & Dividend NonAffiliated	**26,671**	**587**	**26,084**	**-**
4190005	Interest Income - Assoc CBP	137	137	0	0
	Interest & Dividend Affiliated	**137**	**137**	**-**	**-**
	Total Interest & Dividend Income	**26,808**	**724**	**26,084**	**-**
	Interest & Dividend Carrying Charge	**-**	**-**	**-**	**-**
	Memo: Total Interest & Dividend Income w/ Carrying	**26,808**	**724**	**26,084**	**-**
9260042	SERP Pension - Non-Service	(1,070)	(998)	(72)	0
9260043	OPEB - Non-Service	485,297	204,328	271,484	9,486
9260062	Pension Plan - Non-Service	426,652	39,628	403,022	(15,998)
9260064	Def AEPSC Pension Settlement	(476)	(184)	(292)	0
	Other Components of Net Periodic Pension	**910,403**	**242,774**	**674,141**	**(6,512)**
4191000	Allw Oth Fnds Usd Drng Cnstr	187,734	64,790	9,433	113,510
	AFUDC	**187,734**	**64,790**	**9,433**	**113,510**
	Gain on Disposition of Equity Investments	**-**	**-**	**-**	**-**
	Interest LTD FMB	**-**	**-**	**-**	**-**
4270002	Int on LTD - Install Pur Contr	(509,167)	(509,167)	0	0
	Interest LTD IPC	**(509,167)**	**(509,167)**	**-**	**-**
	Interest LTD Notes Payable - Affiliated	**-**	**-**	**-**	**-**
	Interest LTD Notes Payable - NonAffiliated	**-**	**-**	**-**	**-**
	Interest LTD Debentures	**-**	**-**	**-**	**-**
4270006	Int on LTD - Sen Unsec Notes	(9,255,708)	(9,255,708)	0	0
	Interest LTD Senior Unsecured	**(9,255,708)**	**(9,255,708)**	**-**	**-**
	Interest LTD Other - Affil	**-**	**-**	**-**	**-**
4270005	Int on LTD - Other LTD	(2,604,442)	(2,604,442)	0	0
	Interest LTD Other - NonAffil	**(2,604,442)**	**(2,604,442)**	**-**	**-**

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INCOME STATEMENT

IS8016
YTD Feb 2025
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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Feb 2025	Kentucky Power Company - Distribution 110 Actual YTD Feb 2025	Kentucky Power Company - Generation 117 Actual YTD Feb 2025	Kentucky Power Company - Transmission 180 Actual YTD Feb 2025
	Interest on Long-Term Debt	**(12,369,317)**	**(12,369,317)**	**-**	**-**
4300003	Int to Assoc Co - CBP	(341,141)	5,838,761	(8,239,206)	2,059,305
	Interest STD - Affil	**(341,141)**	**5,838,761**	**(8,239,206)**	**2,059,305**
4310007	Lines Of Credit	(118,180)	(38,657)	(55,516)	(24,007)
	Interest STD - NonAffil	**(118,180)**	**(38,657)**	**(55,516)**	**(24,007)**
	Interest on Short Term Debt	**(459,321)**	**5,800,104**	**(8,294,723)**	**2,035,297**
4280002	Amrtz Debt Dscnt&Exp-Instl Pur	(28,763)	(28,763)	0	0
4280003	Amrtz Debt Dscnt&Exp-N/P	(3,721)	(3,721)	0	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	(95,357)	(95,357)	0	0
	Amort of Debt Disc. Prem & Exp	**(127,841)**	**(127,841)**	**-**	**-**
4281004	Amrtz Loss Rcquired Debt-Dbnt	(5,608)	(5,608)	0	0
	Amort Loss on Reacquired Debt	**(5,608)**	**(5,608)**	**-**	**-**
	Amort Gain on Reacquired Debt	**-**	**-**	**-**	**-**
	Other Interest - Fuel Recovery	**-**	**-**	**-**	**-**
4310001	Other Interest Expense	2,271,004	3,418	2,265,182	2,403
4310002	Interest on Customer Deposits	(256,264)	(256,264)	0	0
9310005	Int on Regulated Fin Leases	(2,962)	0	0	0
	Other Interest - NonAffil	**2,011,777**	**(252,846)**	**2,265,182**	**2,403**
	Other Interest Expense - Affil	**-**	**-**	**-**	**-**
	Interest Rate Hedge Unrealized (Gain)/Loss	**-**	**-**	**-**	**-**
4320000	Allw Brrwed Fnds Used Cnstr-Cr	520,644	180,701	20,845	319,099
	AFUDC-Borrowed Funds	**520,644**	**180,701**	**20,845**	**319,099**
	Total Interest Charges	**(10,429,667)**	**(6,774,808)**	**(6,008,696)**	**2,356,800**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**(348,933)**	**(6,788,569)**	**(22,904,109)**	**29,343,745**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	785,858	(1,851,410)	(4,402,259)	7,039,528
4092001	Inc Tax, Oth Inc&Ded-Federal	(51,446)	(47,088)	1,911	(6,269)
	Federal Current Income Tax	**734,412**	**(1,898,499)**	**(4,400,348)**	**7,033,259**
4101001	Prov Def I/T Util Op Inc-Fed	6,411,386	1,599,680	3,764,650	1,047,056
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(6,883,411)	(1,075,536)	(4,320,934)	(1,486,941)
	Federal Deferred Income Tax	**(472,025)**	**524,144**	**(556,284)**	**(439,885)**
	Federal Investment Tax Credits	**-**	**-**	**-**	**-**
	Federal Income Taxes	**262,387**	**(1,374,355)**	**(4,956,632)**	**6,593,373**
4091002	Income Taxes, UOI - State	(315,415)	(526,866)	(1,091,190)	1,302,642
4092002	Inc Tax, Oth Inc & Ded - State	(12,920)	(11,826)	480	(1,574)
	State Current Income Tax	**(328,335)**	**(538,692)**	**(1,090,710)**	**1,301,067**
	State Deferred Income Tax	**-**	**-**	**-**	**-**
	State Investment Tax Credits	**-**	**-**	**-**	**-**
	State Income Taxes	**(328,335)**	**(538,692)**	**(1,090,710)**	**1,301,067**
	Local Current Income Tax	**-**	**-**	**-**	**-**
	Local Deferred Income Tax	**-**	**-**	**-**	**-**
	Local Investment Tax Credits	**-**	**-**	**-**	**-**
	Local Income Taxes	**-**	**-**	**-**	**-**
	Foreign Current Income Tax	**-**	**-**	**-**	**-**
	Foreign Deferred Income Tax	**-**	**-**	**-**	**-**
	Foreign Investment Tax Credits	**-**	**-**	**-**	**-**
	Foreign Income Taxes	**-**	**-**	**-**	**-**

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INCOME STATEMENT

IS8016
YTD Feb 2025
03/08/2025 13:01

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

	Kentucky Power Int Consol IS8016 Actual YTD Feb 2025	Kentucky Power Company - Distribution 110 Actual YTD Feb 2025	Kentucky Power Company - Generation 117 Actual YTD Feb 2025	Kentucky Power Company - Transmission 180 Actual YTD Feb 2025
Total Income Taxes	(65,948)	(1,913,047)	(6,047,342)	7,894,441
Equity Earnings of Subs	-	-	-	-
INCOME AFTER INCOME TAXES and EQUITY EARNINGS	(282,985)	(4,875,522)	(16,856,767)	21,449,304
Discontinued Operations (Net of Taxes)	-	-	-	-
Cumulative Effect of Accounting Changes	-	-	-	-
Extraordinary Income / (Expenses)	-	-	-	-
NET INCOME	(282,985)	(4,875,522)	(16,856,767)	21,449,304
Minority Interest	-	-	-	-
Preferred Stock Dividend Subs	-	-	-	-
Earnings to Common Shareholders	(282,985)	(4,875,522)	(16,856,767)	21,449,304
NET INCOME (LOSS) NODE before PS	(282,985)	(4,875,522)	(16,856,767)	21,449,304
Double Check on Net Income Node after PS	0	-	-	-

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BS8216 YTD Feb 2025 03/11/2025 17:51	BALANCE SHEET	Kentucky Power Int Consol	Kentucky Power Company - Distribution	Kentucky Power Company - Generation	Kentucky Power Company - Transmission
		BS8216	110	117	180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Feb 2025	YTD Feb 2025	YTD Feb 2025	YTD Feb 2025
	ASSETS				
	Cash and Cash Equivalents	**1,468,315**	**1,468,315**	**0**	**0**
	Other Cash Deposits	**22,976**	**12,667**	**10,042**	**267**
	Customers	17,519,080	14,029,877	924,926	2,564,278
	Accrued Unbilled Revenues	3,314,047	3,314,047	0	0
	Miscellaneous Accounts Receivable	16,556,512	4,075,616	62,201,562	19,579,016
	Allowances for Uncollectible Accounts	(236)	(236)	0	0
	Accounts Receivable	**37,389,403**	**21,419,304**	**63,126,488**	**22,143,293**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**77,557,825**	**5,694,868**	**68,784,967**	**3,077,989**
	Risk Management Contracts - Current	**8,478,576**	**0**	**8,478,576**	**0**
	Margin Deposits	**4,443,562**	**7,161**	**4,436,402**	**0**
	Unrecovered Fuel - Current	**11,006,432**	**0**	**11,006,432**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**1,818,719**	**1,447,273**	**244,117**	**127,330**
	TOTAL CURRENT ASSETS	**142,185,808**	**30,049,587**	**156,087,023**	**25,348,880**
	Electric Production	**1,291,966,126**	**1,341,966,016**	**1,326,271,998**	**961,392,179**
	Electric Transmission	**956,910,968**	**0**	**0**	**0**
	Electric Distribution	**1,207,692,315**	**0**	**0**	**0**
	General Property, Plant and Equipment	**174,218,319**	**83,276**	**(45,138)**	**1,119,396**
	Construction Work-in-Progress	**126,892,148**	**50,314,823**	**5,579,164**	**70,998,161**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,757,679,876**	**1,392,364,115**	**1,331,806,024**	**1,033,509,736**
	less: Accumulated Depreciation and Amortization	**(1,266,905,594)**	**(337,076,829)**	**(659,970,906)**	**(269,857,860)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,490,774,281**	**1,055,287,286**	**671,835,119**	**763,651,876**
	Net Regulatory Assets	**605,083,366**	**140,680,414**	**454,306,598**	**10,096,354**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**747,340**	**0**	**747,340**	**0**
	Employee Benefits and Pension Assets	**38,771,635**	**17,416,165**	**20,546,432**	**809,038**
	Other Non Current Assets	**43,862,813**	**14,513,297**	**24,405,669**	**4,943,847**
	TOTAL OTHER NON-CURRENT ASSETS	**688,465,154**	**172,609,876**	**500,006,039**	**15,849,239**
	TOTAL ASSETS	**3,321,425,243**	**1,257,946,749**	**1,327,928,182**	**804,849,995**
	LIABILITIES				
	Accounts Payable	**121,450,438**	**108,872,482**	**66,846,357**	**15,031,282**
	Advances from Affiliates	**15,586,053**	**(774,515,457)**	**1,069,403,207**	**(279,301,697)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**300,000,000**	**300,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	249,931	6,584	243,347	0
2440021	S/T Liability MTM Collateral	(6,584)	(6,584)	0	0
	Risk Management Liabilities - MTM	243,347	0	243,347	0
	Risk Management Liabilities	**243,347**	**0**	**243,347**	**0**
	Accrued Taxes	**37,629,032**	**(3,651,034)**	**(31,344,125)**	**72,624,190**

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BS8216 YTD Feb 2025 03/11/2025 17:51	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Feb 2025	YTD Feb 2025	YTD Feb 2025	YTD Feb 2025
	Memo: Property Taxes	33,737,006	17,718,919	5,540,644	10,477,442
	Accrued Interest	**19,829,522**	**19,829,522**	**0**	**0**
	Risk Management Collateral	496,705	0	496,705	0
	Utility Customer Deposits	37,968,525	37,968,525	0	0
	Deposits - Customer and Collateral	**38,465,229**	**37,968,525**	**496,705**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	139,159	61,258	77,901	0
	Obligations under Operating Leases - Current	363,479	223,016	63,102	77,361
	Tax Collections Payable	2,866,466	2,866,466	0	0
	Revenue Refunds - Accrued	334,518	0	126,695	207,823
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	1,027,496	914,426	100,878	12,192
	Accrued Rents	(4,826)	(4,826)	0	0
	Accrued ICP	2,175,710	1,997,690	167,780	10,239
	Accrued Vacations	2,407,527	2,147,463	238,446	21,618
	Misc Employee Benefits	1,076,005	895,357	179,484	1,164
	Payroll Deductions	107,674	95,450	10,328	1,897
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	179,057	178,937	120	0
2530022	Customer Advance Receipts	1,659,283	1,659,283	0	0
	Customer Advance	1,659,283	1,659,283	0	0
2420511	Control Cash Disburse Account	1,297,316	1,297,316	0	0
	Control Cash Disbursement Account	1,297,316	1,297,316	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	163,541	0	163,541	0
2300002	ARO - Current	3,620,144	0	3,620,144	0
2420088	Econ. Development Fund Curr	750,024	750,024	0	0
2420512	Unclaimed Funds	16,001	16,001	0	0
2420542	Acc Cash Franchise Req	96,927	96,927	0	0
242059225	Sales Use Tax - Leased Equip	30	0	0	30
2420643	Accrued Audit Fees	57,851	31,850	16,225	9,775
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	670,423	667,702	0	2,721
2530112	Other Deferred Credits-Curr	55,821	55,821	0	0
2530124	Contr In Aid of Constr Advance	852,683	852,683	0	0
	Misc Current and Accrued Liabilities	6,284,130	2,471,694	3,799,911	12,526
	Current Other and Accrued Liabilities	19,410,358	14,519,256	4,623,642	267,460
	Other Current Liabilities	**19,912,995**	**14,803,530**	**4,764,644**	**344,821**
	TOTAL CURRENT LIABILITIES	**553,116,616**	**(296,692,433)**	**1,110,410,134**	**(191,301,404)**
	Long-Term Debt - Affiliated	**0**	**0**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,061,195,851**	**1,061,195,851**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(581,750)**	**(581,750)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,060,614,101*	*1,060,614,101*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
	Long-Term Risk Management Liabilities - MTM	0	0	0	0
	Long-Term Risk Management Liabilities	**0**	**0**	**0**	**0**
	Deferred Income Taxes	**484,152,545**	**169,018,472**	**220,680,607**	**94,453,466**

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BS8216 YTD Feb 2025 03/11/2025 17:51	BALANCE SHEET	Kentucky Power Int Consol	Kentucky Power Company - Distribution	Kentucky Power Company - Generation	Kentucky Power Company - Transmission
		BS8216	110	117	180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Feb 2025	YTD Feb 2025	YTD Feb 2025	YTD Feb 2025
	Deferred Investment Tax Credits	**0**	**0**	**0**	**0**
	Regulatory Liabilities and Deferred Credits	**124,689,513**	**90,909,482**	**34,516**	**33,745,515**
	Memo - Reg Liab and Def ITC	*124,689,513*	*90,909,482*	*34,516*	*33,745,515*
	Asset Retirement Obligation	**85,963,007**	**221,032**	**85,741,975**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**8,726,514**	**13,986,676**	**(7,045,976)**	**1,785,815**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redemp	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	831,061	687,988	143,072	0
	Obligations Under Operating Leases	2,496,694	2,041,222	168,660	286,812
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	101,503	101,503	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530044	Neigh Help Neig-Cust Donations	(12)	(12)	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	23,134	23,134	0	0
2530101	MACSS Unidentified EDI Cash	61	61	0	0
2530185	O\U Accounting of ExpensesT	4,320	0	4,320	0
2530188	Long Term Assoc AP	8,454,603	0	0	8,454,603
2530190	QUAL OF SVC PENALTIES - LT	72,870	0	0	72,870
	Def Credits - Other	8,554,976	23,183	4,320	8,527,473
	Total Other Deferred Credits	8,656,480	124,686	4,320	8,527,473
	Accumulated Provisions - Rate Refund	1,546,223	0	0	1,546,223
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**13,530,458**	**2,853,897**	**316,052**	**10,360,508**
	TOTAL NON-CURRENT LIABILITIES	**1,777,676,136**	**1,337,603,659**	**299,727,174**	**140,345,304**
	TOTAL LIABILITIES	**2,330,792,752**	**1,040,911,225**	**1,410,137,308**	**(50,956,099)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,069,518**	**106,025,371**	**335,469,573**	**84,574,574**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**414,112,973**	**88,606,103**	**(427,966,303)**	**753,473,173**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**990,632,491**	**217,035,524**	**(82,209,127)**	**855,806,094**
	Memo: Total Equity	990,632,491	217,035,524	(82,209,127)	855,806,094
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,321,425,243**	**1,257,946,749**	**1,327,928,182**	**804,849,995**
	out-of-balance	(0)	0	0	(0)

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BS8216 YTD Feb 2024 03/14/2024 16:38	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Feb 2024	YTD Feb 2024	YTD Feb 2024	YTD Feb 2024
	ASSETS				
	Cash and Cash Equivalents	**2,086,044**	**2,086,044**	**0**	**0**
	Other Cash Deposits	**39,370**	**17,496**	**21,256**	**618**
	Customers	12,990,412	11,653,844	700,739	635,829
	Accrued Unbilled Revenues	1,674,274	1,674,274	0	0
	Miscellaneous Accounts Receivable	14,364,231	2,496,147	57,468,848	16,929,444
	Allowances for Uncollectible Accounts	(387)	(355)	(1)	(31)
	Accounts Receivable	**29,028,529**	**15,823,909**	**58,169,586**	**17,565,242**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**97,998,481**	**7,716,610**	**87,209,271**	**3,072,601**
	Risk Management Contracts - Current	**3,069,688**	**6,176**	**3,063,512**	**0**
	Margin Deposits	**2,007,250**	**32,255**	**1,974,995**	**0**
	Unrecovered Fuel - Current	**10,543,723**	**0**	**10,543,723**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**14,031,406**	**13,694,294**	**223,521**	**113,591**
	TOTAL CURRENT ASSETS	**158,804,491**	**39,376,784**	**161,205,864**	**20,752,051**
	Electric Production	**1,239,446,453**	**1,264,083,952**	**1,277,063,293**	**846,382,237**
	Electric Transmission	**841,932,847**	**0**	**0**	**0**
	Electric Distribution	**1,131,149,927**	**0**	**0**	**0**
	General Property, Plant and Equipment	**176,157,789**	**83,276**	(45,138)	**1,119,396**
	Construction Work-in-Progress	**166,497,141**	**55,649,785**	**24,217,388**	**86,629,969**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,555,184,157**	**1,319,817,012**	**1,301,235,543**	**934,131,602**
	less: Accumulated Depreciation and Amortization	(1,213,612,544)	(322,220,171)	(633,060,371)	(258,332,002)
	NET PROPERTY, PLANT and EQUIPMENT	**2,341,571,613**	**997,596,841**	**668,175,172**	**675,799,600**
	Net Regulatory Assets	**554,775,430**	**128,601,150**	**418,150,606**	**8,023,674**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Assets	**25,110,403**	**13,352,282**	**11,008,595**	**749,526**
	Other Non Current Assets	**48,744,001**	**14,475,440**	**27,116,400**	**7,152,161**
	TOTAL OTHER NON-CURRENT ASSETS	**628,629,834**	**156,428,872**	**456,275,601**	**15,925,361**
	TOTAL ASSETS	**3,129,005,938**	**1,193,402,497**	**1,285,656,637**	**712,477,012**
	LIABILITIES				
	Accounts Payable	**69,168,839**	**80,585,151**	**42,234,622**	**8,879,274**
	Advances from Affiliates	**49,351,202**	(766,145,009)	**1,024,075,791**	(208,579,580)
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**215,000,000**	**215,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	7,912,535	0	7,912,535	0
2440021	S/T Liability MTM Collateral	(228,173)	0	(228,173)	0
	Risk Management Liabilities - MTM	7,684,362	0	7,684,362	0
	Risk Management Liabilities	**7,684,362**	**0**	**7,684,362**	**0**
	Accrued Taxes	**47,590,354**	**12,993,645**	(11,351,526)	**45,948,235**
	Memo: Property Taxes	43,135,174	21,801,759	6,573,555	14,759,860
	Accrued Interest	**21,081,940**	**21,081,940**	**0**	**0**

BS8216 YTD Feb 2024 03/14/2024 16:38	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Feb 2024	YTD Feb 2024	YTD Feb 2024	YTD Feb 2024
	Risk Management Collateral	447,943	0	447,943	0
	Utility Customer Deposits	37,631,958	37,631,958	0	0
	Deposits - Customer and Collateral	**38,079,901**	**37,631,958**	**447,943**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	108,169	30,938	77,232	0
	Obligations under Operating Leases - Current	232,819	170,932	59,993	1,895
	Tax Collections Payable	2,723,202	2,723,202	0	0
	Revenue Refunds - Accrued	523,966	0	128,393	395,573
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	912,879	810,124	94,545	8,210
	Accrued Rents	1,686	1,686	0	0
	Accrued ICP	1,919,514	1,790,153	122,755	6,606
	Accrued Vacations	2,673,187	2,395,510	258,942	18,735
	Misc Employee Benefits	1,489,507	737,990	750,606	911
	Payroll Deductions	116,655	92,150	23,240	1,264
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	231,854	209,007	22,847	0
2530022	Customer Advance Receipts	3,087,266	3,087,266	0	0
	Customer Advance	3,087,266	3,087,266	0	0
2420511	Control Cash Disburse Account	4,224,801	4,224,801	0	0
	Control Cash Disbursement Account	4,224,801	4,224,801	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	118,665	0	118,665	0
2300002	ARO - Current	205,678	0	205,678	0
2420000	Misc Current & Accrued Liab	1,000,000	1,000,000	0	0
2420088	Econ. Development Fund Curr	629,036	629,036	0	0
2420512	Unclaimed Funds	17,983	17,983	0	0
2420542	Acc Cash Franchise Req	88,233	88,233	0	0
2420643	Accrued Audit Fees	61,625	25,803	23,371	12,451
2420656	Federal Mitigation Accru (NSR)	244,045	0	244,045	0
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	710,042	708,575	0	1,468
2530112	Other Deferred Credits-Curr	84,852	84,852	0	0
2530124	Contr In Aid of Constr Advance	246,539	246,539	0	0
2530177	Deferred Rev-Bonus Lease Curr	1,897	0	1,897	0
	Misc Current and Accrued Liabilities	3,409,279	2,801,705	593,655	13,919
	Current Other and Accrued Liabilities	21,313,796	18,873,595	1,994,984	445,218
	Other Current Liabilities	**21,654,785**	**19,075,464**	**2,132,209**	**447,112**
	TOTAL CURRENT LIABILITIES	**469,611,383**	**(379,776,850)**	**1,065,223,400**	**(153,304,959)**
	Long-Term Debt - Affiliated	**25,000,000**	**25,000,000**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,060,585,432**	**1,060,585,432**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(648,875)**	**(648,875)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,059,936,557*	*1,059,936,557*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	592,046	0	592,046	0
2440022	L/T Liability MTM Collateral	(121,176)	0	(121,176)	0
	Long-Term Risk Management Liabilities - MTM	470,870	0	470,870	0
	Long-Term Risk Management Liabilities	**470,870**	**0**	**470,870**	**0**
	Deferred Income Taxes	**473,492,477**	**163,668,165**	**220,402,236**	**89,422,076**

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BS8216 YTD Feb 2024 03/14/2024 16:38	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Feb 2024	YTD Feb 2024	YTD Feb 2024	YTD Feb 2024
	Deferred Investment Tax Credits	(0)	**0**	(0)	**0**
	Regulatory Liabilities and Deferred Credits	**103,108,945**	**74,537,349**	**(1,552,836)**	**30,124,432**
	Memo - Reg Liab and Def ITC	*103,108,945*	*74,537,349*	*(1,552,836)*	*30,124,432*
	Asset Retirement Obligation	**18,067,278**	**203,952**	**17,863,325**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**9,385,438**	**11,075,155**	**(3,410,792)**	**1,721,076**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redemp	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	664,063	465,542	198,521	0
	Obligations Under Operating Leases	1,123,915	908,272	215,644	0
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	94,091	94,091	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	37,990	37,990	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	814	0	0	814
2530185	O\U Accounting of ExpensesT	7,889	0	7,889	0
2530188	Long Term Assoc AP	4,099,784	0	0	4,099,784
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	4,231,093	37,990	7,889	4,185,214
	Total Other Deferred Credits	4,325,183	132,081	7,889	4,185,214
	Accumulated Provisions - Rate Refund	943,764	0	0	943,764
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**7,056,925**	**1,505,894**	**422,054**	**5,128,978**
	TOTAL NON-CURRENT LIABILITIES	**1,696,518,490**	**1,335,927,073**	**234,194,856**	**126,396,562**
	TOTAL LIABILITIES	**2,166,129,873**	**956,150,222**	**1,299,418,255**	(26,908,397)
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,771,323**	**106,025,371**	**336,070,072**	**84,675,880**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**385,654,741**	**108,822,854**	(360,119,294)	**636,951,181**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**962,876,065**	**237,252,274**	(13,761,619)	**739,385,409**
	Memo: Total Equity	962,876,065	237,252,274	(13,761,619)	739,385,409
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,129,005,938**	**1,193,402,497**	**1,285,656,637**	**712,477,012**
	out-of-balance	(0)	0	0	(0)

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KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - February, 2025

Final

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		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,324,153,881.22	2,903,743.82	(1,385,804.48)	0.00	0.00	1,325,671,820.56
101/106	CLOUD GENERATION	446,948.71	56,986.55	0.00	0.00	0.00	503,935.26
	TOTAL PRODUCTION	**1,324,600,829.93**	**2,960,730.37**	**(1,385,804.48)**	**0.00**	**0.00**	**1,326,175,755.82**
101/106	TRANSMISSION	955,494,282.91	7,026,280.85	(1,128,384.65)	0.00	0.00	961,392,179.11
101/106	CLOUD TRANSMISSION	302,831.60	90,774.72	0.00	0.00	0.00	393,606.32
101/106	DISTRIBUTION	1,328,226,510.37	13,619,200.27	(1,490,980.79)	0.00	0.00	1,340,354,729.85
101/106	CLOUD DISTRIBUTION	2,053,474.66	302,437.08	0.00	0.00	0.00	2,355,911.74
	TOTAL (ACCOUNTS 101 & 106)	**3,610,677,929.47**	**23,999,423.29**	**(4,005,169.92)**	**0.00**	**0.00**	**3,630,672,182.84**
1011001/12	CAPITAL LEASES	1,329,493.17	0.00	0.00	80,299.63	0.00	1,409,792.80
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**3,612,007,422.64**	**23,999,423.29**	**(4,005,169.92)**	**80,299.63**	**0.00**	**3,632,081,975.64**
1050001	PLANT HELD FOR FUTURE USE	801,671.21	0.00	0.00	0.00	0.00	801,671.21
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEGINNING BALANCE	115,771,812.73					
107000X	ADDITIONS		34,669,560.41				
107000X	TRANSFERS		(23,549,224.94)				
107000X	ENDING BALANCE		11,120,335.47				126,892,148.20
107000X	**CLOUD CONSTRUCTION WIP:**						
107000X	BEGINNING BALANCE	1,813,515.61					
107000X	ADDITIONS		496,933.01				
107000X	TRANSFERS		(450,198.35)				
107000X	ENDING BALANCE		46,734.66				1,860,250.27
	TOTAL ELECTRIC UTILITY PLANT	**3,730,394,422.19**	**35,166,493.42**	**(4,005,169.92)**	**80,299.63**	**0.00**	**3,761,636,045.32**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	502,365.72	0.00	0.00	0.00	0.00	502,365.72
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1210003	NONUTILITY PROPERTY-WIP						
	BEGINNING BALANCE	0.00					
	ADDITIONS		0.00				
	TRANSFERS		0.00				
	ENDING BALANCE		0.00				0.00
1210016	NONUTILITY PROPERTY-CCNC	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	655,168.37	0.00	0.00	0.00	0.00	655,168.37
	TOTAL NONUTILITY PLANT	**1,157,534.09**	**0.00**	**0.00**	**0.00**	**0.00**	**1,157,534.09**

KPSC Case No. 2025-00257
Application - Section II
Filing Requirements
Exhibit R
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KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - February, 2025

Final

GLR7410 03/11/25 14:44

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
.	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	640,384,146.97	6,707,283.29	(1,385,804.48)	(313,724.68)	12,346,116.78	657,738,017.88
1080001/11	TRANSMISSION	302,596,611.20	4,573,325.13	(1,128,384.65)	(1,584,527.99)	4,645,259.35	309,102,283.04
1080001/11	DISTRIBUTION	407,529,530.89	8,242,698.92	(1,490,980.79)	(354,528.09)	15,948,316.34	429,875,037.27
1080013	PRODUCTION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	0.00	0.00	0.00	0.00	0.00	0.00
	RETIREMENT WORK IN PROGRESS	(14,227,110.14)	0.00	0.00	(2,022,200.60)	2,252,780.76	(13,996,529.98)
	TOTAL (108X accounts)	**1,336,283,178.93**	**19,523,307.34**	**(4,005,169.92)**	**(4,274,981.36)**	**35,192,473.23**	**1,382,718,808.22**
	NUCLEAR					0.00	
1110001	PRODUCTION	11,897,023.95	256,485.02	0.00	0.00	(12,153,508.95)	0.02
1110007	CLOUD IMPLEMENT COST PRODUCT	185,158.67	7,449.15	0.00	0.00	(192,607.83)	(0.01)
1110001	TRANSMISSION	4,426,015.33	127,811.32	0.00	0.00	(4,553,826.66)	(0.01)
1110007	CLOUD IMPLEMENT COST TRANSMI	86,385.47	5,047.19	0.00	0.00	(91,432.69)	(0.03)
1110001	DISTRIBUTION	14,844,619.51	399,905.33	0.00	0.00	(15,185,450.73)	59,074.11
1110007	CLOUD IMPLEMENT COST DISTRIBU	732,931.68	29,933.90	0.00	0.00	(762,865.61)	(0.03)
	TOTAL (111X accounts)	**32,172,134.61**	**826,631.91**	**0.00**	**0.00**	**(32,939,692.47)**	**59,074.05**
1011006	CAPITAL LEASES	414,736.20	0.00	0.00	0.00	21,625.75	436,361.95
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**1,368,870,049.74**	**20,349,939.25**	**(4,005,169.92)**	**(4,274,981.36)**	**2,274,406.51**	**1,383,214,244.22**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	179,574.02	1,111.63	0.00	0.00	0.00	180,685.65
1220002	Depr&Amrt of Nonutl Prop-Leasd	0.00	0.00	0.00	0.00	0.00	0.00
1220003	Depr&Amrt of Nonutl Prop-WIP	0.00	0.00	0.00	0.00	0.00	0.00
1220004	Depletion - Owned	0.00	0.00	0.00	0.00	0.00	0.00
1240027	Other Property - RWIP	35,121.36	0.00	0.00	0.00	0.00	35,121.36
1240028	Other Property - Retirement	(46,947.27)	0.00	0.00	0.00	0.00	(46,947.27)
	TOTAL NONUTILITY PLANT	**167,748.11**	**1,111.63**	**0.00**	**0.00**	**0.00**	**168,859.74**

KPSC Case No. 2025-00257
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Exhibit R
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U.S. Department of Energy
Energy Information Administration
Form EIA-826

Monthly Electric Utility Sales and Revenue Report with State Distributions – 2025

Form Approval
OMB NO.1905-0129
(Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**

Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650.

Utility Name: Kentucky Power Company

Identification Code (Assigned by EIA): 22053

Reporting for the month of: Jan___ Feb_X_ Mar___ Apr___ May___ Jun___ Jul___ Aug___ Sep___ Oct___ Nov___ Dec__ , 2025

Contact Person: Sandra Vargo

Phone number: 614-716-2671

Email: slvargo@aep.com

Fax: 614-716-1449

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	$ 28,621	$ 14,736	$ 12,731	$ -	56,088
	b. Megwatthours	$ 189,740	$ 102,913	$ 156,109	$ -	448,762
	c. Number of consumers	$ 131,027	$ 30,696	$ 940	$ -	162,663
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					

Note:

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April 29th, 2025

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed March 2025 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:

1-12	Income Statement
1-3	Details of Operating Revenues
5-10	Operating Expenses – Functional Expenses
12	Detail Statement of Taxes

Balance Sheet:

13	Balance Sheet – Assets & Other Debits
13-15	Balance Sheet – Liabilities & Other Credits
14-15	Deferred Credits
15	Statement of Retained Earnings

Utility Property:

16-17	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Digitally signed by Brian J. Frantz
DN: cn=Brian J. Frantz, o=AEP, ou=Corporate Accounting, email=bjfrantz@aep.com
Reason: I have reviewed this document
Date: 2025.04.29 13:17:27 -04'00'

Brian J Frantz
Director - Corporate Accounting

American Electric Power

INCOME STATEMENT

IS8016
YTD Mar 2025
04/06/2025 17:22

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Mar 2025	Kentucky Power Company - Distribution 110 Actual YTD Mar 2025	Kentucky Power Company - Generation 117 Actual YTD Mar 2025	Kentucky Power Company - Transmission 180 Actual YTD Mar 2025
		REVENUES				
4400001		Residential Sales-W/Space Htg	53,578,695	54,485,773	(907,078)	0
4400002		Residential Sales-W/O Space Ht	19,526,491	20,296,695	(770,204)	0
4400005		Residential Fuel Rev	24,647,835	24,647,835	0	0
	A	**Revenue - Residential Sales**	**97,753,020**	**99,430,302**	**(1,677,282)**	**-**
4420001		Commercial Sales	26,754,880	27,580,689	(825,809)	0
4420006		Sales to Pub Auth - Schools	4,524,435	4,524,435	0	0
4420007		Sales to Pub Auth - Ex Schools	5,240,261	5,380,485	(140,224)	0
4420013		Commercial Fuel Rev	14,003,118	14,003,118	0	0
	A	**Revenue - Commercial Sales**	**50,522,694**	**51,488,727**	**(966,033)**	**-**
	B	**Revenue - Industrial Sales - Affiliated**	**-**	**-**	**-**	**-**
4420002		Industrial Sales (Excl Mines)	19,328,330	20,303,523	(975,192)	0
4420004		Ind Sales-NonAffil(Incl Mines)	4,414,817	4,414,817	0	0
4420016		Industrial Fuel Rev	17,657,392	17,657,392	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**41,400,539**	**42,375,731**	**(975,192)**	**-**
		Revenue - Industrial Sales	**41,400,539**	**42,375,731**	**(975,192)**	**-**
	A	**Revenue - Gas Products Sales**	**-**	**-**	**-**	**-**
	A	**Revenue - Gas Transportation & Storage Sales**	**-**	**-**	**-**	**-**
	B	**Revenue - Gas Transportation & Storage Sales - Af**	**-**	**-**	**-**	**-**
4440000		Public Street/Highway Lighting	471,238	474,001	(2,762)	0
4440002		Public St & Hwy Light Fuel Rev	89,161	89,161	0	0
	A	**Revenue - Other Retail Sales**	**560,400**	**563,162**	**(2,762)**	**-**
	B	**Revenue - Other Retail Sales - Affiliated**	**-**	**-**	**-**	**-**
		Revenue - Retail Sales	**190,236,652**	**193,857,922**	**(3,621,270)**	**-**
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	24,479,953
4561033		PJM NITS Revenue - Affiliated	21,869,835	0	0	21,869,835
4561034		PJM TO Adm. Serv Rev - Aff	51,041	0	0	51,041
4561035		PJM Affiliated Trans NITS Cost	(14,235,863)	0	(14,235,863)	0
4561036		PJM Affiliated Trans TO Cost	(27,758)	0	(27,758)	0
4561059		Affil PJM Trans Enhancmnt Rev	412,030	0	0	412,030
4561060		Affil PJM Trans Enhancmnt Cost	(268,205)	0	(268,205)	0
4561062		PROVISION RTO Cost - Affi	399,287	0	399,287	0
4561063		PROVISION RTO Rev Affiliated	(82,167)	0	0	(82,167)
	B	**Revenue - Transmission-Affiliated**	**8,118,200**	**-**	**(14,132,539)**	**46,730,691**
4470150		Transm. Rev.-Dedic. Whlsl/Muni	(5,807)	0	(639,328)	633,521
4470206		PJM Trans loss credits-OSS	43,135	0	43,135	0
4470209		PJM transm loss charges-OSS	(66,752)	0	(66,752)	0
4561005		PJM Point to Point Trans Svc	655,352	0	655,352	0
4561006		PJM Trans Owner Admin Rev	25,665	0	0	25,665
4561007		PJM Network Integ Trans Svc	2,941,890	0	0	2,941,890
4561019		Oth Elec Rev Trans Non Affil	16,758	0	0	16,758
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	35	0	0	35
4561029		PJM NITS Revenue Whsl Cus-NAff	743,119	0	0	743,119
4561030		PJM TO Serv Rev Whls Cus-NAff	1,768	0	0	1,768
4561045		PJM Non-Aff Gen IPP Rev	5,982	0	0	5,982
4561058		NonAffil PJM Trans Enhncmt Rev	473,102	0	0	473,102
4561061		NAff PJM RTEP Rev for Whsl-FR	14,000	0	0	14,000

American Electric Power

IS8016 YTD Mar 2025 04/06/2025 17:22		INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
		Layout: IS8016				
17A V2099-01-01		Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025
4561064		PROVISION RTO Rev WhslCus-NAf	(2,760)	0	0	(2,760)
4561065		PROVISION RTO Rev - NonAff	(12,345)	0	0	(12,345)
	A	**Revenue - Transmission-NonAffiliated**	**4,833,141**	**-**	**(7,593)**	**4,840,734**
		Revenue - Transmission	**12,951,341**	**-**	**(14,140,132)**	**51,571,426**
	B	**Revenue - Resale-Affiliated**	**-**	**-**	**-**	**-**
4470027		Whsal/Muni/Pb Ath Fuel Rev	922,432	0	922,432	0
4470033		Whsal/Muni/Pub Auth Base Rev	655,186	0	655,186	0
4470082		Financial Electric Realized	(1,369)	0	(1,369)	0
4470089		PJM Energy Sales Margin	287,801	0	287,801	0
4470098		PJM Oper.Reserve Rev-OSS	(19,812)	0	(19,812)	0
4470099		Capacity Cr. Net Sales	(30,326)	0	(30,326)	0
4470100		PJM FTR Revenue-OSS	37,014	0	37,014	0
4470103		PJM Energy Sales Cost	2,980,937	0	2,980,937	0
4470115		PJM Meter Corrections-OSS	(9,862)	0	(9,862)	0
4470116		PJM Meter Corrections-LSE	(148,383)	0	(148,383)	0
4470126		PJM Incremental Imp Cong-OSS	(42,276)	0	(42,276)	0
4470175		OSS Sharing Reclass - Retail	1,611,573	0	1,611,573	0
4470176		OSS Sharing Reclass-Reduction	(1,611,573)	0	(1,611,573)	0
4470220		PJM Regulation - OSS	1,401,448	0	1,401,448	0
4470221		PJM Spinning Reserve - OSS	28,692	0	28,692	0
5550080		PJM Hourly Net Purch.-FERC	(1,339,281)	0	(1,339,281)	0
	A	**Revenue - Resale-NonAffiliated**	**4,722,200**	**-**	**4,722,200**	**-**
	A	**Revenue - Resale-Realized**	**-**	**-**	**-**	**-**
	A	**Revenue - Resale-Risk Mgmt MTM**	**-**	**-**	**-**	**-**
	A	**Revenue - Resale-Risk Mgmt Activities**	**-**	**-**	**-**	**-**
		Revenue - Sales for Resale	**4,722,200**	**-**	**4,722,200**	**-**
4470074		Sale for Resale-Aff-Trnf Price	0	0	125,540,052	0
4540001		Rent From Elect Property - Af	484,449	291,753	0	294,707
	B	**Revenue - Other Ele-Affilliated**	**484,449**	**291,753**	**125,540,052**	**294,707**
4500000		Forfeited Discounts	334,139	334,139	0	0
4510001		Misc Service Rev - Nonaffil	22,384	22,310	0	74
4540002		Rent From Elect Property-NAC	705,172	525	685,672	18,975
4540005		Rent from Elec Prop-Pole Attch	1,183,745	1,181,637	0	2,107
4560007		Oth Elect Rev - DSM Program	189,359	189,359	0	0
5010040		Gas Procuremnt Sales Net	(453,288)	0	(453,288)	0
		Revenue - Other Ele-NonAffilliated	**1,981,511**	**1,727,970**	**232,384**	**21,156**
		Revenue - Gas	**-**	**-**	**-**	**-**
		Gain/(Loss) on Allowances	**-**	**-**	**-**	**-**
	A	**Revenue - Other Ele-NonAffilliated**	**1,981,511**	**1,727,970**	**232,384**	**21,156**
		Revenue - Other Opr Electric	**2,465,960**	**2,019,723**	**125,772,436**	**315,863**
	D	**Revenue Merchandising & Contract Work**	**-**	**-**	**-**	**-**
	C	**Revenues Non-Utility Operations - Affiliat**	**-**	**-**	**-**	**-**
4170004		Rev from Non-Util Oper NonAfil	81,566	81,566	0	0
	D	**Revenues Non-Utility Operations - NonAff**	**81,566**	**81,566**	**-**	**-**
		Revenues from Non-Utility Operations	**81,566**	**81,566**	**-**	**-**
	C	**Non-Operating Rental Income - Affiliated**	**-**	**-**	**-**	**-**
4180001		Non-Operatng Rental Income	400	400	0	0

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American Electric Power

INCOME STATEMENT

IS8016
YTD Mar 2025
04/06/2025 17:22

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Mar 2025	Kentucky Power Company - Distribution 110 Actual YTD Mar 2025	Kentucky Power Company - Generation 117 Actual YTD Mar 2025	Kentucky Power Company - Transmission 180 Actual YTD Mar 2025
4180005		Non-Opratng Rntal Inc-Depr	(1,667)	0	0	(1,667)
	D	**Non-Operating Rental Income - NonAffiliat**	**(1,267)**	**400**	**-**	**(1,667)**
		Non-Operating Rental Income	**(1,267)**	**400**	**-**	**(1,667)**
	C	**Non-Operating Misc Income -Affiliated**	**-**	**-**	**-**	**-**
4210002		Misc Non-Op Inc-NonAsc-Rents	322	0	322	0
4210007		Misc Non-Op Inc - NonAsc - Oth	247	223	24	0
	D	**Non-Operating Misc Income - NonAffiliate**	**569**	**223**	**346**	**-**
		Non-Operating Misc Income	**569**	**223**	**346**	**-**
4560015		Other Electric Revenues - ABD	142,648	142,648	0	0
	D	**Associated Business Development Income**	**142,648**	**142,648**	**-**	**-**
		Revenue - Other Opr - Other	**223,516**	**224,838**	**346**	**(1,667)**
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	***-***	***-***	***-***	***-***
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***223,516***	***224,838***	***346***	***(1,667)***
		Revenue - Other Operating	**2,689,476**	**2,244,561**	**125,772,782**	**314,196**
4491005		Prov Trans Refunds NonAffil WV	(60,327)	0	0	(60,327)
4491006		Prov Trans Refunds Retail WV	(13,643)	0	0	(13,643)
	A	**Provision for Rate Refund - NonAffiliated**	**(73,970)**	**-**	**-**	**(73,970)**
4491007		Prov Trans Refunds Affil WV	(403,513)	0	0	(403,513)
	B	**Provision for Rate Refund - Affiliated**	**(403,513)**	**-**	**-**	**(403,513)**
		Provision for Rate Refund	**(477,483)**	**-**	**-**	**(477,483)**
	A	**Revenue - Power Sales**	**-**	**-**	**-**	**-**
		TOTAL OPERATING REVENUES	**210,122,186**	**196,102,482**	**112,733,581**	**51,408,138**
	=(A)	*Memo: G/T/D Revenue*	*201,699,534*	*195,585,892*	*1,325,721*	*4,787,921*
	=(B)	*Memo: Other Affiliated Re*	*8,199,136*	*291,753*	*111,407,513*	*46,621,885*
	=(C)	*Memo: Revenue-Oth Opr-*	*-*	*-*	*-*	*-*
	=(D)	*Memo: Revenue-Oth Opr-*	*223,516*	*224,838*	*346*	*(1,667)*
		Memo: Total Operating Reve	*210,122,186*	*196,102,482*	*112,733,581*	*51,408,138*
	=(E)=(B)+(C)	*Memo: Affiliated Revenue*	***8,199,136***	***291,753***	***111,407,513***	***46,621,885***
	=(F)=(D)+(A)	*Memo: Non-Affiliated Rev*	***201,923,050***	***195,810,729***	***1,326,068***	***4,786,253***
		Memo: Total Operating Reve	***210,122,186***	***196,102,482***	***112,733,581***	***51,408,138***
		FUEL EXPENSES				
5010000		Fuel	2,702,271	0	2,702,271	0
5010001		Fuel Consumed	16,994,934	0	16,994,934	0
5010003		Fuel - Procure Unload & Handle	858,578	0	858,578	0
5010012		Ash Sales Proceeds	3,335	0	3,335	0
5010019		Fuel Oil Consumed	1,105,998	0	1,105,998	0
5010020		Nat Gas Consumed Steam	12,913,004	0	12,913,004	0
5010021		Transp Gas Consumed Steam	109,045	0	109,045	0
5010027		Gypsum handling/disposal costs	367,663	0	367,663	0
5010028		Gypsum Sales Proceeds	(399,446)	0	(399,446)	0
5010034		Gas Transp Res Fees-Steam	1,615,564	0	1,615,564	0
		Fuel Expense Total	**36,270,947**	**-**	**36,270,947**	**-**
5010005		Fuel - Deferred	(566,695)	0	(566,695)	0
		Deferred Fuel Expense	**(566,695)**	**-**	**(566,695)**	**-**
		Over Under Fuel Expense				

KPSC Case No. 2025-00257
Application - Section II
Filing Requirements
Exhibit R
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American Electric Power

IS8016 YTD Mar 2025 04/06/2025 17:22	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025
	Fuel for Electric Generation	**35,704,253**	**-**	**35,704,253**	**-**
	Fuel from Affiliates for Electric Generation	**-**	**-**	**-**	**-**
5090000	Allow Consum Title IV SO2	5,255	0	5,255	0
5090009	Allow Consumpt CSAPR SO2	26	0	26	0
	Allowances - Consumption	**5,281**	**-**	**5,281**	**-**
5020002	Urea Expense	233,236	0	233,236	0
5020004	Lime-Related Expenses	430,054	0	430,054	0
	Emissions Control - Chemicals	**663,290**	**-**	**663,290**	**-**
	Total Fuel for Electric Generation	**36,372,823**	**-**	**36,372,823**	**-**
	Memo: NonAff Fuel/Allow/Emissions	***36,372,823***	**-**	***36,372,823***	**-**
5550029	Purch Power-Assoc-Trnsfr Price	0	125,540,052	0	0
	Purchased Electricity from AEP - Affiliates	**-**	**125,540,052**	**-**	**-**
5550001	Purch Pwr-NonTrading-Nonassoc	44,015,431	0	44,015,431	0
5550023	Purch Power Capacity -NA	604,645	0	604,645	0
5550039	PJM Inadvertent Mtr Res-OSS	(1,139)	0	(1,139)	0
5550040	PJM Inadvertent Mtr Res-LSE	(16,542)	0	(16,542)	0
5550074	PJM Reactive-Charge	830,812	0	830,812	0
5550075	PJM Reactive-Credit	(358,719)	0	(358,719)	0
5550076	PJM Black Start-Charge	97,439	0	97,439	0
5550078	PJM Regulation-Charge	277,134	0	277,134	0
5550079	PJM Regulation-Credit	212,918	0	212,918	0
5550083	PJM Sync & Non Sync-Charge	274,305	0	274,305	0
5550084	PJM Sync & Non Sync-Credit	(42,939)	0	(42,939)	0
5550123	PJM OpRes-LSE-Charge	3,313,080	0	3,313,080	0
5550124	PJM Implicit Congestion-LSE	2,465,234	0	2,465,234	0
5550132	PJM FTR Revenue-LSE	(4,778,155)	0	(4,778,155)	0
5550137	PJM OpRes-LSE-Credit	(16,087)	0	(16,087)	0
5550326	PJM Transm Loss Charges - LSE	2,344,461	0	2,344,461	0
5550327	PJM Transm Loss Credits-LSE	(1,218,349)	0	(1,218,349)	0
5550328	PJM FC Penalty Credit	(1,597)	0	(1,597)	0
	Purchased Electricity for Resale - NonAffiliated	**48,001,931**	**-**	**48,001,931**	**0**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**
	Purchased Gas for Resale - NonAffiliated	**-**	**-**	**-**	**-**
	Total Purchased Power	**48,001,931**	**125,540,052**	**48,001,931**	**0**
	GROSS MARGIN	**125,747,432**	**70,562,431**	**28,358,827**	**51,408,138**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	987,489	5,010	979,690	2,789
5020000	Steam Expenses	495,576	0	495,576	0
5050000	Electric Expenses	2,812	0	2,812	0
5060000	Misc Steam Power Expenses	1,151,923	(19,112)	1,165,338	5,698
5060002	Misc Steam Power Exp-Assoc	14,384	0	14,384	0
5070006	Rents - Associated	580	0	580	0
	Steam Generation Op Exp	**2,652,764**	**(14,102)**	**2,658,379**	**8,487**
	Nuclear Generation Op Exp	**-**	**-**	**-**	**-**
5390000	Misc Hydr Power Generation Exp	(0)	0	0	0
	Hydro Generation Op Exp	**(0)**	**-**	**-**	**-**

American Electric Power

INCOME STATEMENT

IS8016
YTD Mar 2025
04/06/2025 17:22

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Mar 2025	Kentucky Power Company - Distribution 110 Actual YTD Mar 2025	Kentucky Power Company - Generation 117 Actual YTD Mar 2025	Kentucky Power Company - Transmission 180 Actual YTD Mar 2025
5560000	Sys Control & Load Dispatching	13,229	0	13,229	0
5570000	Other Expenses	192,452	0	192,452	0
5570007	Other Pwr Exp - Wholesale RECs	243	243	0	0
5581300	Oper Supervision & Engineering	372	59	257	56
5581400	Wind Turb Gen&Oth PInt Op-Mjr	1,032	224	595	213
5582000	Solar Panel Gen&Oth Plt Op-Mjr	10	0	10	0
5757000	PJM Admin-MAM&SC- OSS	16,028	0	16,028	0
5757001	PJM Admin-MAM&SC- Internal	388,783	0	388,783	0
	Other Generation Op Exp	**612,150**	**526**	**611,354**	**269**
5600000	Oper Supervision & Engineering	593,592	12,872	4,435	576,286
5612000	Load Dispatch-Mntr&Op TransSys	108,186	870	123	107,193
5613000	Load Dispatch-Trans Srvc&Sched	174	0	0	174
5614000	PJM Admin-SSC&DS-OSS	17,762	0	17,762	0
5614001	PJM Admin-SSC&DS-Internal	379,807	0	379,807	0
5615000	Reliability,Plng&Stds Develop	14,347	358	50	13,939
5618000	PJM Admin-RP&SDS-OSS	6,607	0	6,607	0
5618001	PJM Admin-RP&SDS- Internal	128,414	0	128,414	0
5620001	Station Expenses - Nonassoc	70,966	6,898	0	64,068
5630000	Overhead Line Expenses	3,290	0	0	3,290
5650002	Transmssn Elec by Others-NAC	32,079	0	32,079	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	24,479,953	0	0
5650012	PJM Trans Enhancement Charge	515,646	0	515,646	0
5650015	PJM TO Serv Exp - Aff	47,502	0	47,502	0
5650016	PJM NITS Expense - Affiliated	18,872,488	0	18,872,488	0
5650019	Affil PJM Trans Enhncement Exp	1,196,552	0	1,196,552	0
5650020	PROVISION RTO Affl Expense	(353,885)	0	(353,885)	0
5650021	PJM NITS Expense - Non-Affilia	286,043	0	286,043	0
5650023	Amort of PROVISION RTO Expense	2,381,856	0	2,381,856	0
5660000	Misc Transmission Expenses	170,054	(51,328)	976	220,406
5660011	Misc Transm Exp - Affiliate	910	0	0	910
5670001	Rents - Nonassociated	250	0	0	250
5670002	Rents - Associated	0	0	0	102,011
	Transmission Op Exp	**24,472,642**	**24,449,623**	**23,516,456**	**1,088,527**
5800000	Oper Supervision & Engineering	482,502	479,948	243	2,322
5810000	Load Dispatching	306	306	0	0
5820000	Station Expenses	80,797	79,323	4	1,470
5830000	Overhead Line Expenses	397,597	397,729	0	(14)
5840000	Underground Line Expenses	90,080	90,085	0	(5)
5850000	Street Lighting & Signal Sys E	2,425	2,427	0	0
5860000	Meter Expenses	284,361	284,437	15	139
5870000	Customer Installations Exp	36,009	36,009	4	17
5880000	Miscellaneous Distribution Exp	627,373	623,903	241	3,451
5890001	Rents - Nonassociated	305,935	305,935	0	0
5890002	Rents - Associated	3,094	3,094	0	0
	Distribution Op Exp	**2,310,479**	**2,303,195**	**507**	**7,381**
9010000	Supervision - Customer Accts	6,391	6,402	(3)	(9)
9020000	Meter Reading Expenses	4,158	4,158	0	0

American Electric Power

IS8016 YTD Mar 2025 04/06/2025 17:22	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025
9020002	Meter Reading - Regular	91,092	91,127	0	0
9020003	Meter Reading - Large Power	8,006	8,006	0	0
9030000	Cust Records & Collection Exp	88,655	86,556	9	2,090
9030001	Customer Orders & Inquiries	703,138	702,978	45	125
9030002	Manual Billing	1,878	1,878	0	0
9030003	Postage - Customer Bills	160,516	160,516	0	0
9030004	Cashiering	13,843	13,843	0	0
9030005	Collection Agents Fees & Exp	981	981	0	0
9030006	Credit & Oth Collection Activi	76,807	76,767	7	61
9030007	Collectors	71,549	71,549	0	0
9030009	Data Processing	(315)	(315)	0	0
9040007	Uncoll Accts - Misc Receivable	(5,673)	(5,673)	0	0
9050000	Misc Customer Accounts Exp	9,314	9,314	0	0
9070000	Supervision - Customer Service	4,874	4,870	0	4
9080000	Customer Assistance Expenses	292,843	292,854	0	0
9080004	Cust Assistnce Exp - DSM - Ind	41	35	0	6
9080009	Cust Assistance Expense - DSM	152,636	152,636	0	0
9100000	Misc Cust Svc&Informational Ex	10,320	5,092	2,631	2,597
9100001	Misc Cust Svc & Info Exp - RCS	(97)	(51)	0	(45)
	Customer Service and Information Op Exp	**1,690,956**	**1,683,522**	**2,689**	**4,829**
9120000	Demonstrating & Selling Exp	1,117	1,117	0	0
9120003	Demo & Selling Exp - Area Dev	3	3	0	0
	Sales Expenses	**1,120**	**1,120**	**-**	**-**
	Memo: Insurance (9240 9250)	**613,973**	**274,088**	**266,979**	**72,905**
9200000	Administrative & Gen Salaries	2,956,085	1,518,908	979,021	458,158
9210001	Off Supl & Exp - Nonassociated	317,284	194,227	88,604	34,497
9210003	Office Supplies & Exp - Trnsf	64	22	29	13
9210021	EMP TRAVEL - Airfare	34	12	15	7
9210022	MEALS & ENT-100 Pct DEDUCTIBLE	37	23	12	2
9210023	EMP TRAVEL-MILEAGE	78	51	25	2
9210024	EMP TRAVEL-PARKING	7	4	3	1
9210025	MEALS & ENT-50 Pct DEDUCTIBLE	18	11	6	1
9210026	EMP TRAVEL-CAR RENTAL	10	7	3	0
9210027	EMP TRAVEL-TAXI AND SHUTTLE	8	5	3	0
9210028	EMP TRAVEL-HOTEL & LODGING	149	77	56	16
9210030	EMP TRAVEL-OTHER	1	0	0	0
9210032	FUEL	2	2	1	0
9210033	FOOD SERVICE-CATERING	40	13	18	8
9210034	In-House Training & Seminars	14	0	0	14
9210037	OEM/TECHNICAL TRAINING	317	0	317	0
9210040	DUES-BUSINESS/PROFESSIONAL	81	28	37	17
9210041	VEHICLE-LICENSE FEES	10	3	4	2
9220000	Administrative Exp Trnsf - Cr	(44,774)	(44,524)	0	(250)
9220001	Admin Exp Trnsf to Cnstrction	(110,115)	(110,115)	0	0
9220002	Admin Exp Trnsf Const-Mngerial	0	0	0	0
9220004	Admin Exp Trnsf to ABD	(178)	(178)	0	0
9220005	Overhead Loadings	(156,570)	(114,718)	(32,548)	(9,305)

American Electric Power

INCOME STATEMENT

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YTD Mar 2025
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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

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9230001	Outside Svcs Empl - Nonassoc	599,732	66,781	265,781	267,171
9230003	AEPSC Billed to Client Co	(294,114)	(100,907)	(116,022)	(77,185)
9230031	SRV-OUTSIDE SERVICES (TECH)	84	28	38	18
9230034	SRV-SOFTWARE LICENSING	1,836	1,092	328	415
9230064	Def AEPSC Pension Settlement	3,464	1,242	1,108	1,114
9240000	Property Insurance	264,228	66,455	151,351	46,422
9250000	Injuries and Damages	474,314	327,000	121,041	26,273
9250002	Emp Accdent Prvntion-Adm Exp	(95)	(32)	(34)	(29)
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	(63,758)	(59,302)	(4,899)	443
9250007	Prsnal Injries&Prop Dmage-Pub	986	0	986	0
9250010	Frg Ben Loading - Workers Comp	(61,702)	(60,032)	(1,466)	(204)
9260000	Employee Pensions & Benefits	591	591	0	0
9260002	Pension & Group Ins Admin	6,902	3,174	3,622	106
9260003	Pension Plan	518,462	346,581	167,577	4,305
9260004	Group Life Insurance Premiums	33,909	22,286	11,373	250
9260005	Group Medical Ins Premiums	1,392,091	963,543	412,304	16,243
9260007	Group L-T Disability Ins Prem	108,982	62,972	45,867	143
9260009	Group Dental Insurance Prem	43,496	29,825	13,139	533
9260010	Training Administration Exp	283	136	104	43
9260012	Employee Activities	1,498	1,105	372	22
9260021	Postretirement Benefits - OPEB	18,891	10,565	8,021	305
9260027	Savings Plan Contributions	457,686	311,843	142,461	3,381
9260036	Deferred Compensation	9,525	9,525	0	0
9260037	Supplemental Pension	1,629	1,394	235	0
9260050	Frg Ben Loading - Pension	(214,036)	(184,676)	(24,997)	(4,364)
9260051	Frg Ben Loading - Grp Ins	(567,640)	(486,804)	(69,690)	(11,146)
9260052	Frg Ben Loading - Savings	(178,870)	(151,574)	(23,842)	(3,453)
9260053	Frg Ben Loading - OPEB	(10,209)	(7,577)	(2,180)	(452)
9260055	IntercoFringeOffset- Don't Use	(103,962)	(103,962)	0	0
9260058	Frg Ben Loading - Accrual	(51,310)	(51,784)	3,996	(3,522)
9270000	Franchise Requirements	40,098	40,098	0	0
9280000	Regulatory Commission Exp	8,212	3,610	2,362	2,241
9280002	Regulatory Commission Exp-Case	245,649	75,435	83,773	86,441
9280005	Reg Com Exp-FERC Trans Cases	3,675	289	246	3,140
9280006	State Publ Serv CommissionFees	238,299	238,299	0	0
9301000	General Advertising Expenses	5,000	5,000	0	0
9301001	Newspaper Advertising Space	912	405	256	250
9301003	TV Station Advertising Time	837	372	235	230
9301006	Spec Corporate Comm Info Proj	1,137	1,137	0	0
9301007	Special Adv Space & Prod Exp	750	750	0	0
9301012	Public Opinion Surveys	4,330	4,330	0	0
9301015	Other Corporate Comm Exp	890	890	0	0
9302000	Misc General Expenses	50,033	(17,107)	35,702	31,438
9302003	Corporate & Fiscal Expenses	24,562	16,716	6,314	1,532
9302004	Research, Develop&Demonstr Exp	24	18	0	6
9310001	Rents - Real Property	2,400	2,400	0	0
9310002	Rents - Personal Property	12,576	10,721	1,734	131

American Electric Power

IS8016 YTD Mar 2025 04/06/2025 17:22	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025
	Administration & General	**5,994,877**	**2,846,707**	**2,272,801**	**875,425**
4111005	Accretion Expense	579,398	4,670	574,727	0
	Accretion	**579,398**	**4,670**	**574,727**	**-**
4116000	Gain From Disposition of Plant	(4,131)	(4,131)	0	0
	Loss/(Gain) on Utility Plant	**(4,131)**	**(4,131)**	**-**	**-**
9302006	Assoc Bus Dev - Materials Sold	13,303	13,283	0	20
9302007	Assoc Business Development Exp	55,909	50,013	33	5,869
	Associated Business Development Expenses	**69,213**	**63,296**	**33**	**5,889**
4211000	Gain on Dspsition of Property	(53)	0	0	(53)
	Gain on Disposition of Property	**(53)**	**-**	**-**	**(53)**
	Loss on Disposition of Property	**-**	**-**	**-**	**-**
	Loss(Gain) of Sale of Property	**(53)**	**-**	**-**	**(53)**
4265009	Factored Cust A/R Exp - Affil	914,772	914,772	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	289,965	289,965	0	0
	Opr Exp and Factored A/R	**1,204,738**	**1,204,738**	**-**	**-**
	Water Heaters	**-**	**-**	**-**	**-**
4030047	Depr Exp - Cloud Computing	136,346	95,876	23,515	16,956
4265004	Social & Service Club Dues	665	665	0	0
4265007	Regulatory Expenses	1,320	585	372	363
	Expense of Non-Utility Operation	**138,331**	**97,126**	**23,887**	**17,319**
4210009	Misc Non-Op Exp - NonAssoc	337	142	86	110
	Misc NonOp Expenses - NonAssoc	**337**	**142**	**86**	**110**
4261000	Donations	418,610	416,850	760	1,000
	Donation Contributions	**418,610**	**416,850**	**760**	**1,000**
4263001	Penalties	1	1	1	0
	Provision for Penalties	**1**	**1**	**1**	**0**
4264000	Civic and Political Activity	46,025	21,318	12,454	12,255
4264001	Non-deduct Lobbying per IRS	7,334	1,816	4,370	1,148
	Civic & Political Activities	**53,359**	**23,135**	**16,824**	**13,403**
4265002	Other Deductions - Nonassoc	182,794	4,314	167,729	10,752
	Other Deductions	**182,794**	**4,314**	**167,729**	**10,752**
	Shutdown Coal Company Expenses	**-**	**-**	**-**	**-**
	All Other Operational Expenses	**1,998,170**	**1,746,305**	**209,285**	**42,583**
	Operational Expenses	**40,377,582**	**33,080,732**	**29,846,232**	**2,033,335**
5100000	Maint Supv & Engineering	260,842	0	260,841	0
5110000	Maintenance of Structures	453,456	0	453,456	0
5120000	Maintenance of Boiler Plant	3,869,658	0	3,869,658	0
5120034	BSDR O/U Recovery - Maint Cost	(587)	0	(587)	0
5120037	KY Steam Maint O/U	(174,813)	0	(174,813)	0
5130000	Maintenance of Electric Plant	1,493,259	0	1,493,259	0
5132000	Maint of Computer Software-Mjr	17,168	0	17,168	0
5133000	Maint of Comm Equipmt-Mjr	412	0	412	0
5140000	Maintenance of Misc Steam Plt	405,346	0	405,346	0
	Steam Generation Maintenance	**6,324,739**	**-**	**6,324,739**	**0**
	Nuclear Generation Maintenance	**-**	**-**	**-**	**-**
	Hydro Generation Maintenance	**-**	**-**	**-**	**-**

American Electric Power

INCOME STATEMENT

IS8016
YTD Mar 2025
04/06/2025 17:22

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Mar 2025	Kentucky Power Company - Distribution 110 Actual YTD Mar 2025	Kentucky Power Company - Generation 117 Actual YTD Mar 2025	Kentucky Power Company - Transmission 180 Actual YTD Mar 2025
5587000	Maint Solar Pnl Strct & Eq-Mjr	41	6	30	6
	Other Generation Maintenance	**41**	**6**	**30**	**6**
5680000	Maint Supv & Engineering	2,750	1	242	2,507
5690000	Maintenance of Structures	14,204	0	0	14,204
5691000	Maint of Computer Hardware	1,205	40	17	1,149
5692000	Maint of Computer Software	29,945	7	51	29,887
5693000	Maint of Communication Equip	2,126	35	0	2,091
5700000	Maint of Station Equipment	188,995	1	2	188,992
5710000	Maintenance of Overhead Lines	1,175,202	1,192	0	1,174,014
5720000	Maint of Underground Lines	179	0	0	179
5730000	Maint of Misc Trnsmssion Plt	3,161	0	0	3,161
	Transmission Maintenance	**1,417,767**	**1,276**	**312**	**1,416,184**
5900000	Maint Supv & Engineering	18,644	18,598	0	50
5910000	Maintenance of Structures	7,218	7,049	0	169
5920000	Maint of Station Equipment	142,916	137,530	65	5,321
5923000	Maint of Computer Software-Mjr	32,005	32,005	0	0
5924000	Maint of Comm Equipmt-Mjr	225,587	225,587	0	0
5930000	Maintenance of Overhead Lines	9,249,119	9,349,431	43	(97,393)
5930001	Tree and Brush Control	90,639	90,686	0	0
5940000	Maint of Underground Lines	13,457	13,446	0	15
5950000	Maint of Lne Trnf,Rglators&Dvi	1,293	1,292	0	2
5960000	Maint of Strt Lghtng & Sgnal S	1,574	1,574	0	0
5970000	Maintenance of Meters	9,509	9,514	0	0
5980000	Maint of Misc Distribution Plt	3,990	3,931	1	58
	Distribution Maintenance	**9,795,953**	**9,890,643**	**109**	**(91,779)**
9350000	Maintenance of General Plant	1,016	1,016	0	0
9350001	Maint of Structures - Owned	57,379	56,061	656	662
9350002	Maint of Structures - Leased	1,313	1,030	123	160
9350013	Maint of Cmmncation Eq-Unall	(211)	0	0	0
9351000	Maint of Computer Hardware	1,102	846	243	14
9352000	Maint of Computer Software	196,693	70,681	110,982	15,030
9353000	Maint of Comm Equipmt	35,120	28,836	5,984	299
	Administration & General Maintenance	**292,412**	**158,471**	**117,988**	**16,164**
	All Other Maintenance Expenses	**-**	**-**	**-**	**-**
	Maintenance Expenses	**17,830,912**	**10,050,396**	**6,443,178**	**1,340,575**
	Total Operational and Maintenance Expenses	**58,208,494**	**43,131,127**	**36,289,409**	**3,373,910**
4030046	Capitalized Software Depr Exp	2,365,083	1,205,116	770,723	389,244
4040001	Amort. of Plant	(98,530)	(30,697)	(46,858)	(20,976)
4060001	Amort of Plt Acq Adj	9,654	0	0	9,654
	DDA Amortization	**2,276,207**	**1,174,419**	**723,865**	**377,922**
4073014	Regulatory Debit - BSDR	51,846	0	51,846	0
	DDA Regulatory Debits	**51,846**	**-**	**51,846**	**-**
4074000	Regulatory Credits	(122,044)	(122,044)	0	0
4074025	PPA RIDER Over/Under	1,315,363	0	1,315,363	0
	DDA Regulatory Credits	**1,193,320**	**(122,044)**	**1,315,363**	**-**
	Amortization	**3,521,372**	**1,052,376**	**2,091,074**	**377,922**

American Electric Power

INCOME STATEMENT

IS8016
YTD Mar 2025
04/06/2025 17:22

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Mar 2025	Kentucky Power Company - Distribution 110 Actual YTD Mar 2025	Kentucky Power Company - Generation 117 Actual YTD Mar 2025	Kentucky Power Company - Transmission 180 Actual YTD Mar 2025
4030001	Depreciation Exp	27,699,395	11,759,344	9,192,769	6,747,282
4030029	Over/Undr Depr Exp Var Riders	1,381,795	0	1,381,795	0
	DDA Depreciation	**29,081,190**	**11,759,344**	**10,574,564**	**6,747,282**
	DDA STP Nuclear Decommissioning	**-**	**-**	**-**	**-**
4031001	Depr - Asset Retirement Oblig	477,601	2,568	475,034	0
	DDA Asset Retirement Obligation	**477,601**	**2,568**	**475,034**	**-**
	DDA Removal Costs	**-**	**-**	**-**	**-**
	Depreciation	**29,558,791**	**11,761,912**	**11,049,597**	**6,747,282**
	Depreciation and Amortization	**33,080,164**	**12,814,288**	**13,140,672**	**7,125,205**
	Franchise Taxes	**-**	**-**	**-**	**-**
408100624	State Gross Receipts Tax	126	0	0	126
408100625	State Gross Receipts Tax	4,624	0	4,624	0
	Revenue-kWhr Taxes	**4,750**	**-**	**4,624**	**126**
4081002	FICA	896,201	629,544	259,534	7,123
4081003	Federal Unemployment Tax	11,290	6,868	4,295	127
4081007	State Unemployment Tax	20,183	6,907	13,155	120
4081033	Fringe Benefit Loading - FICA	(335,829)	(285,146)	(44,449)	(6,234)
4081034	Fringe Benefit Loading - FUT	(1,656)	(1,453)	(167)	(36)
4081035	Fringe Benefit Loading - SUT	(1,762)	(1,163)	(600)	0
	Payroll Taxes	**588,425**	**355,557**	**231,768**	**1,100**
408102023	State Business Occup Taxes	(84,375)	0	(84,375)	0
408102024	State Business Occup Taxes	(550,825)	0	(550,825)	0
408102025	State Business Occup Taxes	1,761,469	0	1,761,469	0
	Capacity Taxes	**1,126,270**	**-**	**1,126,270**	**-**
408100523	Real Personal Property Taxes	787,566	0	787,566	0
408100524	Real Personal Property Taxes	3,746,100	2,119,332	364,041	1,262,727
408102925	Real-Pers Prop Tax-Cap Leases	165,576	156,402	5,280	3,894
408103625	Real Prop Tax-Cap Leases	3,750	3,750	0	0
408200524	Real Personal Property Taxes	34,926	1,242	16,987	16,697
	Property Taxes	**4,737,918**	**2,280,726**	**1,173,874**	**1,283,318**
	Regulatory Fees	**-**	**-**	**-**	**-**
408101424	Federal Excise Taxes	1,073	0	1,073	0
	Production Taxes	**1,073**	**-**	**1,073**	**-**
408101924	State Sales and Use Taxes	1,795	1,795	0	0
408101925	State Sales and Use Taxes	13,239	3,991	9,249	0
	Miscellaneous Taxes	**15,034**	**5,785**	**9,249**	**-**
	Other Non-Income Taxes	**16,107**	**5,785**	**10,322**	**-**
	Taxes Other Than Income Taxes	**6,473,471**	**2,642,068**	**2,546,858**	**1,284,544**
	TOTAL OPERATING EXPENSES	**97,762,128**	**58,587,483**	**51,976,940**	**11,783,659**
	Memo: SEC Total Operating Expense	**182,136,883**	**184,127,535**	**136,351,694**	**11,783,659**
	OPERATING INCOME	**27,985,304**	**11,974,947**	**(23,618,113)**	**39,624,479**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	40,554	883	39,671	0
	Interest & Dividend NonAffiliated	**40,554**	**883**	**39,671**	**-**

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INCOME STATEMENT

IS8016
YTD Mar 2025
04/06/2025 17:22

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Mar 2025	Kentucky Power Company - Distribution 110 Actual YTD Mar 2025	Kentucky Power Company - Generation 117 Actual YTD Mar 2025	Kentucky Power Company - Transmission 180 Actual YTD Mar 2025
4190005	Interest Income - Assoc CBP	137	137	0	0
	Interest & Dividend Affiliated	**137**	**137**	**-**	**-**
	Total Interest & Dividend Income	**40,691**	**1,020**	**39,671**	**-**
	Interest & Dividend Carrying Charge	**-**	**-**	**-**	**-**
	Memo: Total Interest & Dividend Income w/ Ca	**40,691**	**1,020**	**39,671**	**-**
9260042	SERP Pension - Non-Service	(1,514)	(1,326)	(187)	0
9260043	OPEB - Non-Service	719,703	300,605	404,442	14,656
9260062	Pension Plan - Non-Service	628,209	63,602	589,317	(24,710)
9260064	Def AEPSC Pension Settlement	(476)	(184)	(292)	0
	Other Components of Net Periodic Pension	**1,345,923**	**362,697**	**993,280**	**(10,053)**
4191000	Allw Oth Fnds Usd Drng Cnstr	461,409	150,926	22,994	287,489
	AFUDC	**461,409**	**150,926**	**22,994**	**287,489**
	Gain on Disposition of Equity Investments	**-**	**-**	**-**	**-**
	Interest LTD FMB	**-**	**-**	**-**	**-**
4270002	Int on LTD - Install Pur Contr	(763,750)	(763,750)	0	0
	Interest LTD IPC	**(763,750)**	**(763,750)**	**-**	**-**
	Interest LTD Notes Payable - Affiliated	**-**	**-**	**-**	**-**
	Interest LTD Notes Payable - NonAffiliated	**-**	**-**	**-**	**-**
	Interest LTD Debentures	**-**	**-**	**-**	**-**
4270006	Int on LTD - Sen Unsec Notes	(13,883,563)	(13,883,563)	0	0
	Interest LTD Senior Unsecured	**(13,883,563)**	**(13,883,563)**	**-**	**-**
	Interest LTD Other - Affil	**-**	**-**	**-**	**-**
4270005	Int on LTD - Other LTD	(3,984,384)	(3,984,384)	0	0
	Interest LTD Other - NonAffil	**(3,984,384)**	**(3,984,384)**	**-**	**-**
	Interest on Long-Term Debt	**(18,631,696)**	**(18,631,696)**	**-**	**-**
4300003	Int to Assoc Co - CBP	(468,316)	8,895,047	(12,553,720)	3,190,356
	Interest STD - Affil	**(468,316)**	**8,895,047**	**(12,553,720)**	**3,190,356**
4310007	Lines Of Credit	(171,804)	(58,679)	(76,714)	(36,411)
	Interest STD - NonAffil	**(171,804)**	**(58,679)**	**(76,714)**	**(36,411)**
	Interest on Short Term Debt	**(640,120)**	**8,836,368**	**(12,630,433)**	**3,153,945**
4280002	Amrtz Debt Dscnt&Exp-Instl Pur	(43,145)	(43,145)	0	0
4280003	Amrtz Debt Dscnt&Exp-N/P	(5,651)	(5,651)	0	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	(143,536)	(143,036)	(500)	0
	Amort of Debt Disc. Prem & Exp	**(192,332)**	**(191,832)**	**(500)**	**-**
4281004	Amrtz Loss Rcquired Debt-Dbnt	(8,413)	(8,413)	0	0
	Amort Loss on Reacquired Debt	**(8,413)**	**(8,413)**	**-**	**-**
	Amort Gain on Reacquired Debt	**-**	**-**	**-**	**-**
	Other Interest - Fuel Recovery	**-**	**-**	**-**	**-**
4310001	Other Interest Expense	3,288,964	3,095	3,281,458	4,412
4310002	Interest on Customer Deposits	(391,683)	(391,683)	0	0
9310005	Int on Regulated Fin Leases	(3,990)	0	0	0
	Other Interest - NonAffil	**2,893,291**	**(388,588)**	**3,281,458**	**4,412**
	Other Interest Expense - Affil	**-**	**-**	**-**	**-**
	Interest Rate Hedge Unrealized (Gain)/Loss	**-**	**-**	**-**	**-**
4320000	Allw Brrwed Fnds Used Cnstr-Cr	767,454	257,774	33,843	475,837

American Electric Power

IS8016 YTD Mar 2025 04/06/2025 17:22	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025
	AFUDC-Borrowed Funds	**767,454**	**257,774**	**33,843**	**475,837**
	Total Interest Charges	**(15,811,817)**	**(10,126,387)**	**(9,315,633)**	**3,634,194**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**14,021,510**	**2,363,203**	**(31,877,801)**	**43,536,108**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	1,213,962	(2,472,508)	(5,976,743)	9,663,213
4092001	Inc Tax, Oth Inc&Ded-Federal	(112,344)	(75,337)	(30,114)	(6,893)
	Federal Current Income Tax	**1,101,618**	**(2,547,845)**	**(6,006,857)**	**9,656,319**
4101001	Prov Def I/T Util Op Inc-Fed	13,322,287	4,763,782	6,982,990	1,575,515
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(11,413,365)	(1,679,447)	(7,656,963)	(2,076,956)
	Federal Deferred Income Tax	**1,908,922**	**3,084,335**	**(673,972)**	**(501,440)**
	Federal Investment Tax Credits	-	-	-	-
	Federal Income Taxes	**3,010,540**	**536,490**	**(6,680,829)**	**9,154,879**
4091002	Income Taxes, UOI - State	(332,260)	(711,836)	(1,545,536)	1,925,112
4092002	Inc Tax, Oth Inc & Ded - State	(28,214)	(18,920)	(7,563)	(1,731)
	State Current Income Tax	**(360,474)**	**(730,756)**	**(1,553,099)**	**1,923,381**
	State Deferred Income Tax	-	-	-	-
	State Investment Tax Credits	-	-	-	-
	State Income Taxes	**(360,474)**	**(730,756)**	**(1,553,099)**	**1,923,381**
	Local Current Income Tax	-	-	-	-
	Local Deferred Income Tax	-	-	-	-
	Local Investment Tax Credits	-	-	-	-
	Local Income Taxes	-	-	-	-
	Foreign Current Income Tax	-	-	-	-
	Foreign Deferred Income Tax	-	-	-	-
	Foreign Investment Tax Credits	-	-	-	-
	Foreign Income Taxes	-	-	-	-
	Total Income Taxes	**2,650,066**	**(194,266)**	**(8,233,928)**	**11,078,260**
	Equity Earnings of Subs	-	-	-	-
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	**11,371,445**	**2,557,470**	**(23,643,873)**	**32,457,848**
	Discontinued Operations (Net of Taxes)	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-
	NET INCOME	**11,371,445**	**2,557,470**	**(23,643,873)**	**32,457,848**
	Minority Interest	-	-	-	-
	Preferred Stock Dividend Subs	-	-	-	-
	Earnings to Common Shareholders	**11,371,445**	**2,557,470**	**(23,643,873)**	**32,457,848**
	NET INCOME (LOSS) NODE before PS	**11,371,445**	**2,557,470**	**(23,643,873)**	**32,457,848**
	Double Check on Net Income Node after PS	(0)	(0)	-	-

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BS8216 YTD Mar 2025 04/07/2025 21:55	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025
	ASSETS				
	Cash and Cash Equivalents	**1,495,437**	**1,495,437**	**0**	**0**
	Other Cash Deposits	**22,976**	**12,667**	**10,042**	**267**
	Customers	19,239,375	15,598,971	963,615	2,676,789
	Accrued Unbilled Revenues	4,297,536	4,297,536	0	0
	Miscellaneous Accounts Receivable	18,372,156	4,696,282	63,607,282	19,527,973
	Allowances for Uncollectible Accounts	(69)	(69)	0	0
	Accounts Receivable	**41,908,998**	**24,592,720**	**64,570,898**	**22,204,762**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**78,082,801**	**5,814,665**	**69,367,008**	**2,901,128**
	Risk Management Contracts - Current	**6,144,737**	**0**	**6,144,737**	**0**
	Margin Deposits	**4,342,661**	**9,293**	**4,333,368**	**0**
	Unrecovered Fuel - Current	**9,201,275**	**0**	**9,201,275**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**2,160,061**	**1,780,612**	**266,793**	**112,656**
	TOTAL CURRENT ASSETS	**143,358,946**	**33,705,393**	**153,894,121**	**25,218,814**
	Electric Production	**1,292,209,825**	**1,346,713,911**	**1,326,025,828**	**963,650,709**
	Electric Transmission	**959,258,748**	**0**	**0**	**0**
	Electric Distribution	**1,213,518,923**	**0**	**0**	**0**
	General Property, Plant and Equipment	**172,560,487**	**83,276**	**(45,138)**	**1,119,396**
	Construction Work-in-Progress	**142,918,766**	**49,018,036**	**5,860,560**	**88,040,170**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,780,466,747**	**1,395,815,222**	**1,331,841,251**	**1,052,810,275**
	less: Accumulated Depreciation and Amortization	**(1,269,510,677)**	**(337,075,429)**	**(662,201,090)**	**(270,234,158)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,510,956,070**	**1,058,739,793**	**669,640,160**	**782,576,117**
	Net Regulatory Assets	**617,267,557**	**151,392,058**	**455,619,017**	**10,256,481**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**1,028,454**	**0**	**1,028,454**	**0**
	Employee Benefits and Pension Assets	**38,973,828**	**17,500,704**	**20,659,451**	**813,673**
	Other Non Current Assets	**41,746,221**	**13,294,690**	**24,031,023**	**4,420,508**
	TOTAL OTHER NON-CURRENT ASSETS	**699,016,060**	**182,187,451**	**501,337,945**	**15,490,663**
	TOTAL ASSETS	**3,353,331,075**	**1,274,632,638**	**1,324,872,227**	**823,285,593**
	LIABILITIES				
	Accounts Payable	**125,157,792**	**107,583,720**	**61,404,310**	**25,629,143**
	Advances from Affiliates	**28,174,926**	**(765,654,152)**	**1,080,927,220**	**(287,098,143)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**300,000,000**	**300,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	267,869	4,603	263,266	0
2440021	S/T Liability MTM Collateral	(4,603)	(4,603)	0	0
	Risk Management Liabilities - MTM	263,266	0	263,266	0
	Risk Management Liabilities	**263,266**	**0**	**263,266**	**0**
	Accrued Taxes	**37,936,861**	**(4,601,580)**	**(33,422,096)**	**75,960,537**

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BS8216 YTD Mar 2025 04/07/2025 21:55	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025
	Memo: Property Taxes	33,742,411	17,724,325	5,540,644	10,477,442
	Accrued Interest	**19,066,236**	**19,066,236**	**0**	**0**
	Risk Management Collateral	496,705	0	496,705	0
	Utility Customer Deposits	37,905,638	37,905,638	0	0
	Deposits - Customer and Collateral	**38,402,342**	**37,905,638**	**496,705**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	135,978	58,434	77,544	0
	Obligations under Operating Leases - Current	393,379	253,001	62,652	77,726
	Tax Collections Payable	2,723,267	2,723,267	0	0
	Revenue Refunds - Accrued	313,736	0	126,695	187,041
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	1,118,747	994,781	109,501	14,465
	Accrued Rents	0	0	0	0
	Accrued ICP	318,687	295,515	20,790	2,382
	Accrued Vacations	2,511,582	2,237,226	248,919	25,438
	Misc Employee Benefits	1,375,256	1,210,813	164,938	(495)
	Payroll Deductions	104,507	92,388	10,223	1,897
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	199,546	186,455	13,091	0
2530022	Customer Advance Receipts	1,871,698	1,871,698	0	0
	Customer Advance	1,871,698	1,871,698	0	0
2420511	Control Cash Disburse Account	766,125	766,125	0	0
	Control Cash Disbursement Account	766,125	766,125	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	163,541	0	163,541	0
2300002	ARO - Current	3,620,144	0	3,620,144	0
2420088	Econ. Development Fund Curr	608,240	608,240	0	0
2420512	Unclaimed Funds	16,001	16,001	0	0
2420542	Acc Cash Franchise Req	108,748	108,748	0	0
242059225	Sales Use Tax - Leased Equip	30	0	0	30
2420643	Accrued Audit Fees	92,199	50,022	26,415	15,763
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	617,902	615,442	0	2,460
2530112	Other Deferred Credits-Curr	269,564	244,253	25,311	0
2530124	Contr In Aid of Constr Advance	962,636	962,636	0	0
	Misc Current and Accrued Liabilities	6,459,690	2,606,027	3,835,411	18,253
	Current Other and Accrued Liabilities	17,762,841	12,984,293	4,529,568	248,980
	Other Current Liabilities	**18,292,198**	**13,295,729**	**4,669,763**	**326,706**
	TOTAL CURRENT LIABILITIES	**567,293,621**	**(292,404,409)**	**1,114,339,168**	**(185,181,757)**
	Long-Term Debt - Affiliated	**0**	**0**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,061,254,248**	**1,061,254,248**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(576,156)**	**(576,156)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,060,678,091*	*1,060,678,091*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
	Long-Term Risk Management Liabilities - MTM	0	0	0	0
	Long-Term Risk Management Liabilities	**0**	**0**	**0**	**0**
	Deferred Income Taxes	**487,513,922**	**172,322,716**	**220,716,480**	**94,474,726**

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BS8216 YTD Mar 2025 04/07/2025 21:55	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025	YTD Mar 2025
	Deferred Investment Tax Credits	**0**	**0**	**0**	**0**
	Regulatory Liabilities and Deferred Credits	**126,643,471**	**92,016,413**	(242,148)	**34,869,206**
	Memo - Reg Liab and Def ITC	*126,643,471*	*92,016,413*	*(242,148)*	*34,869,206*
	Asset Retirement Obligation	**86,322,160**	**222,614**	**86,099,546**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**8,609,502**	**14,165,235**	(7,349,558)	**1,793,825**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redemp	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	823,079	686,378	136,701	0
	Obligations Under Operating Leases	2,797,803	2,354,096	163,541	280,166
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	101,503	101,503	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530044	Neigh Help Neig-Cust Donations	12	0	12	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	21,759	21,759	0	0
2530175	Legal Contingencies	0	(274)	274	0
2530185	O\U Accounting of ExpensesT	4,442	0	4,442	0
2530188	Long Term Assoc AP	8,590,739	0	0	8,590,739
2530190	QUAL OF SVC PENALTIES - LT	72,870	0	0	72,870
	Def Credits - Other	8,689,822	21,485	4,728	8,663,609
	Total Other Deferred Credits	8,791,325	122,988	4,728	8,663,609
	Accumulated Provisions - Rate Refund	1,571,179	0	0	1,571,179
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**13,983,386**	**3,163,462**	**304,970**	**10,514,954**
	TOTAL NON-CURRENT LIABILITIES	**1,783,750,534**	**1,342,568,532**	**299,529,291**	**141,652,711**
	TOTAL LIABILITIES	**2,351,044,155**	**1,050,164,122**	**1,413,868,460**	(43,529,045)
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,069,518**	**106,025,371**	**335,469,573**	**84,574,574**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**425,767,403**	**96,039,095**	(434,753,409)	**764,481,717**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**1,002,286,921**	**224,468,515**	(88,996,233)	**866,814,638**
	Memo: Total Equity	1,002,286,921	224,468,515	(88,996,233)	866,814,638
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,353,331,075**	**1,274,632,638**	**1,324,872,227**	**823,285,593**
	out-of-balance	(0)	0	0	(0)

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BS8216 YTD Mar 2024 04/29/2024 12:57	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Mar 2024	YTD Mar 2024	YTD Mar 2024	YTD Mar 2024
	ASSETS				
	Cash and Cash Equivalents	**717,629**	**717,629**	**0**	**0**
	Other Cash Deposits	**39,370**	**17,496**	**21,256**	**618**
	Customers	17,289,303	14,217,674	1,261,100	1,810,530
	Accrued Unbilled Revenues	5,027,822	5,027,822	0	0
	Miscellaneous Accounts Receivable	16,844,530	3,772,740	57,462,134	16,952,246
	Allowances for Uncollectible Accounts	(346)	(317)	(1)	(28)
	Accounts Receivable	**39,161,309**	**23,017,918**	**58,723,233**	**18,762,748**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**96,351,900**	**7,448,896**	**85,676,257**	**3,226,747**
	Risk Management Contracts - Current	**1,259,826**	**22,781**	**1,237,045**	**0**
	Margin Deposits	**1,817,188**	**29,220**	**1,787,968**	**0**
	Unrecovered Fuel - Current	**8,011,389**	**0**	**8,011,389**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**6,782,140**	**6,446,117**	**239,348**	**96,676**
	TOTAL CURRENT ASSETS	**154,140,751**	**37,700,057**	**155,696,495**	**22,086,789**
	Electric Production	**1,238,718,138**	**1,267,148,797**	**1,275,322,746**	**846,706,505**
	Electric Transmission	**842,503,670**	**0**	**0**	**0**
	Electric Distribution	**1,134,775,925**	**0**	**0**	**0**
	General Property, Plant and Equipment	**174,337,849**	**83,276**	**(45,138)**	**1,119,396**
	Construction Work-in-Progress	**172,337,583**	**57,400,238**	**24,115,483**	**90,821,863**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,562,673,165**	**1,324,632,310**	**1,299,393,091**	**938,647,764**
	less: Accumulated Depreciation and Amortization	**(1,217,926,419)**	**(323,162,343)**	**(634,532,578)**	**(260,231,498)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,344,746,746**	**1,001,469,967**	**664,860,513**	**678,416,266**
	Net Regulatory Assets	**552,870,108**	**129,344,578**	**415,320,646**	**8,204,883**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**287,349**	**321**	**287,028**	**0**
	Employee Benefits and Pension Assets	**25,349,733**	**13,403,804**	**11,198,250**	**747,679**
	Other Non Current Assets	**46,642,430**	**13,781,183**	**26,304,869**	**6,556,378**
	TOTAL OTHER NON-CURRENT ASSETS	**625,149,620**	**156,529,886**	**453,110,794**	**15,508,941**
	TOTAL ASSETS	**3,124,037,117**	**1,195,699,910**	**1,273,667,802**	**716,011,995**
	LIABILITIES				
	Accounts Payable	**62,545,649**	**81,342,183**	**35,343,001**	**7,203,055**
	Advances from Affiliates	**53,744,222**	**(759,713,805)**	**1,028,922,381**	**(215,464,354)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**215,000,000**	**215,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	6,767,241	0	6,767,241	0
2440021	S/T Liability MTM Collateral	(301)	0	(301)	0
	Risk Management Liabilities - MTM	6,766,940	0	6,766,940	0
	Risk Management Liabilities	**6,766,940**	**0**	**6,766,940**	**0**
	Accrued Taxes	**50,369,031**	**13,523,652**	**(11,542,399)**	**48,387,778**
	Memo: Property Taxes	43,969,299	22,580,902	6,573,562	14,814,835
	Accrued Interest	**21,236,778**	**21,236,778**	**0**	**0**

BS8216 YTD Mar 2024 04/29/2024 12:57	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Mar 2024	YTD Mar 2024	YTD Mar 2024	YTD Mar 2024
	Risk Management Collateral	447,943	0	447,943	0
	Utility Customer Deposits	37,541,457	37,541,457	0	0
	Deposits - Customer and Collateral	**37,989,400**	**37,541,457**	**447,943**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	117,832	40,324	77,508	0
	Obligations under Operating Leases - Current	183,846	124,679	59,167	0
	Tax Collections Payable	2,407,981	2,407,981	0	0
	Revenue Refunds - Accrued	538,331	0	125,231	413,100
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	998,001	884,795	104,084	9,122
	Accrued Rents	2,410	2,410	0	0
	Accrued ICP	619,713	570,704	46,753	2,256
	Accrued Vacations	2,713,926	2,428,389	266,254	19,283
	Misc Employee Benefits	1,171,325	998,697	170,655	1,973
	Payroll Deductions	114,419	90,026	23,129	1,264
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	225,327	204,427	20,899	0
2530022	Customer Advance Receipts	2,797,132	2,797,132	0	0
	Customer Advance	2,797,132	2,797,132	0	0
2420511	Control Cash Disburse Account	550,611	550,611	0	0
	Control Cash Disbursement Account	550,611	550,611	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	118,665	0	118,665	0
2300002	ARO - Current	205,678	0	205,678	0
2420000	Misc Current & Accrued Liab	1,000,000	1,000,000	0	0
2420088	Econ. Development Fund Curr	691,164	691,164	0	0
2420512	Unclaimed Funds	19,358	19,358	0	0
2420542	Acc Cash Franchise Req	100,176	100,176	0	0
242059224	Sales Use Tax - Leased Equip	222	222	0	0
2420643	Accrued Audit Fees	85,988	36,196	32,451	17,341
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	635,168	633,860	0	1,308
2530112	Other Deferred Credits-Curr	159,467	159,467	0	0
2530124	Contr In Aid of Constr Advance	193,297	193,297	0	0
	Misc Current and Accrued Liabilities	3,209,866	2,834,424	356,793	18,649
	Current Other and Accrued Liabilities	15,349,041	13,769,595	1,113,799	465,647
	Other Current Liabilities	**15,650,720**	**13,934,598**	**1,250,475**	**465,647**
	TOTAL CURRENT LIABILITIES	**463,302,739**	**(377,135,138)**	**1,061,188,342**	**(159,407,874)**
	Long-Term Debt - Affiliated	**25,000,000**	**25,000,000**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,060,645,098**	**1,060,645,098**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(643,281)**	**(643,281)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,060,001,817*	*1,060,001,817*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	89,586	1,072	88,514	0
2440022	L/T Liability MTM Collateral	(1,072)	(1,072)	0	0
	Long-Term Risk Management Liabilities - MTM	88,514	0	88,514	0
	Long-Term Risk Management Liabilities	**88,514**	**0**	**88,514**	**0**
	Deferred Income Taxes	**473,143,382**	**163,903,335**	**219,975,123**	**89,264,924**
	Deferred Investment Tax Credits	**(0)**	**0**	**(0)**	**0**

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BS8216 YTD Mar 2024 04/29/2024 12:57	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Mar 2024	YTD Mar 2024	YTD Mar 2024	YTD Mar 2024
	Regulatory Liabilities and Deferred Credits	**103,162,065**	**75,708,082**	**(2,464,821)**	**29,918,804**
	Memo - Reg Liab and Def ITC	*103,162,064*	*75,708,082*	*(2,464,822)*	*29,918,804*
	Asset Retirement Obligation	**17,973,398**	**205,264**	**17,768,134**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**8,574,494**	**11,252,629**	**(4,406,330)**	**1,728,195**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redem	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	762,881	570,946	191,934	0
	Obligations Under Operating Leases	1,201,664	991,162	210,502	0
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	94,091	94,091	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	36,780	36,780	0	0
2530101	MACSS Unidentified EDI Cash	10,207	10,207	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	740	0	0	740
2530175	Legal Contingencies	(140)	(140)	0	0
2530185	O\U Accounting of ExpensesT	8,110	0	8,110	0
2530188	Long Term Assoc AP	4,041,330	0	0	4,041,330
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	4,181,643	46,847	8,110	4,126,686
	Total Other Deferred Credits	4,275,733	140,938	8,110	4,126,686
	Accumulated Provisions - Rate Refund	835,482	0	0	835,482
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**7,075,760**	**1,703,046**	**410,547**	**4,962,168**
	TOTAL NON-CURRENT LIABILITIES	**1,695,019,429**	**1,337,774,173**	**231,371,166**	**125,874,091**
	TOTAL LIABILITIES	**2,158,322,169**	**960,639,035**	**1,292,559,507**	**(33,533,783)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,771,323**	**106,025,371**	**336,070,072**	**84,675,880**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**388,493,625**	**106,631,455**	**(365,249,381)**	**647,111,550**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**965,714,948**	**235,060,876**	**(18,891,706)**	**749,545,778**
	Memo: Total Equity	965,714,948	235,060,876	(18,891,706)	749,545,778
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,124,037,117**	**1,195,699,910**	**1,273,667,802**	**716,011,995**

KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - March, 2025

Final

GLR7210 04/07/25 22:45

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,324,153,881.22	3,496,575.57	(2,224,806.59)	0.00	0.00	1,325,425,650.20
101/106	CLOUD GENERATION	446,948.71	62,534.06	(6,125.51)	0.00	0.00	503,357.26
	TOTAL PRODUCTION	**1,324,600,829.93**	**3,559,109.63**	**(2,230,932.10)**	**0.00**	**0.00**	**1,325,929,007.46**
101/106	TRANSMISSION	955,494,282.91	9,770,956.71	(1,614,530.72)	0.00	0.00	963,650,708.90
101/106	CLOUD TRANSMISSION	302,831.60	99,265.94	(1,258.48)	0.00	0.00	400,839.06
101/106	DISTRIBUTION	1,328,226,510.37	20,389,576.74	(3,513,462.55)	0.00	0.00	1,345,102,624.56
101/106	CLOUD DISTRIBUTION	2,053,474.66	334,939.74	(134,977.49)	0.00	0.00	2,253,436.91
	TOTAL (ACCOUNTS 101 & 106)	**3,610,677,929.47**	**34,153,848.76**	**(7,495,161.34)**	**0.00**	**0.00**	**3,637,336,616.89**
1011001/12	CAPITAL LEASES	1,329,493.17	0.00	0.00	80,299.63	0.00	1,409,792.80
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**3,612,007,422.64**	**34,153,848.76**	**(7,495,161.34)**	**80,299.63**	**0.00**	**3,638,746,409.69**
1050001	PLANT HELD FOR FUTURE USE	801,671.21	0.00	0.00	0.00	0.00	801,671.21
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEGINNING BALANCE	115,771,812.73					
107000X	ADDITIONS		60,804,062.02				
107000X	TRANSFERS		(33,657,109.02)				
107000X	ENDING BALANCE		27,146,953.00				142,918,765.73
107000X	**CLOUD CONSTRUCTION WIP:**						
107000X	BEGINNING BALANCE	1,813,515.61					
107000X	ADDITIONS		557,810.82				
107000X	TRANSFERS		(496,739.74)				
107000X	ENDING BALANCE		61,071.08				1,874,586.69
	TOTAL ELECTRIC UTILITY PLANT	**3,730,394,422.19**	**61,361,872.84**	**(7,495,161.34)**	**80,299.63**	**0.00**	**3,784,341,433.32**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	502,365.72	0.00	0.00	0.00	0.00	502,365.72
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1210003	NONUTILITY PROPERTY-WIP						
	BEGINNING BALANCE	0.00					
	ADDITIONS		0.00				
	TRANSFERS		0.00				
	ENDING BALANCE		0.00				0.00
1210016	NONUTILITY PROPERTY-CCNC	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	655,168.37	0.00	0.00	0.00	0.00	655,168.37
	TOTAL NONUTILITY PLANT	**1,157,534.09**	**0.00**	**0.00**	**0.00**	**0.00**	**1,157,534.09**

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KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - March, 2025

Final

GLR7410 04/07/25 22:50

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
.	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	640,384,146.97	10,189,706.65	(2,230,932.10)	(426,938.31)	12,151,968.00	660,067,951.21
1080001/11	TRANSMISSION	302,596,611.20	7,014,063.63	(1,615,789.20)	(1,643,044.20)	4,549,736.60	310,901,578.03
1080001/11	DISTRIBUTION	407,529,530.89	12,598,089.56	(3,648,440.04)	(642,331.95)	15,289,461.01	431,126,309.47
1080026	CLOUD COMPUTE IMPLEMENT COST DISTRIBUTION	0.00	34,974.52	0.00	0.00	658,855.33	693,829.85
1080026	CLOUD COMPUTE IMPLEMENT COST PRODUCTION	0.00	8,398.92	0.00	0.00	194,148.78	202,547.70
1080026	CLOUD COMPUTE IMPLEMENT COST TRANSMISSION	0.00	6,560.11	0.00	0.00	95,522.75	102,082.86
1080013	PRODUCTION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	0.00	0.00	0.00	0.00	0.00	0.00
	RETIREMENT WORK IN PROGRESS	(14,227,110.14)	0.00	0.00	(3,464,080.55)	2,712,314.46	(14,978,876.23)
	TOTAL (108X accounts)	**1,336,283,178.93**	**29,851,793.39**	**(7,495,161.34)**	**(6,176,395.01)**	**35,652,006.93**	**1,388,115,422.90**
	NUCLEAR					0.00	
1110001	PRODUCTION	11,897,023.95	256,485.02	0.00	0.00	(12,153,508.95)	0.02
1110007	CLOUD IMPLEMENT COST PRODUCTION	185,158.67	7,449.15	0.00	0.00	(192,607.83)	(0.01)
1110001	TRANSMISSION	4,426,015.33	127,811.32	0.00	0.00	(4,553,826.66)	(0.01)
1110007	CLOUD IMPLEMENT COST TRANSMISSION	86,385.47	5,047.19	0.00	0.00	(91,432.69)	(0.03)
1110001	DISTRIBUTION	14,844,619.51	399,905.33	0.00	0.00	(15,185,450.73)	59,074.11
1110007	CLOUD IMPLEMENT COST DISTRIBUTION	732,931.68	29,933.90	0.00	0.00	(762,865.61)	(0.03)
	TOTAL (111X accounts)	**32,172,134.61**	**826,631.91**	**0.00**	**0.00**	**(32,939,692.47)**	**59,074.05**
1011006	CAPITAL LEASES	414,736.20	0.00	0.00	0.00	32,511.47	447,247.67
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**1,368,870,049.74**	**30,678,425.30**	(7,495,161.34)	(6,176,395.01)	**2,744,825.93**	**1,388,621,744.62**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	179,574.02	1,667.44	0.00	0.00	0.00	181,241.46
1220002	Depr&Amrt of Nonutl Prop-Leasd	0.00	0.00	0.00	0.00	0.00	0.00
1220003	Depr&Amrt of Nonutl Prop-WIP	0.00	0.00	0.00	0.00	0.00	0.00
1220004	Depletion - Owned	0.00	0.00	0.00	0.00	0.00	0.00
1240027	Other Property - RWIP	35,121.36	0.00	0.00	0.00	0.00	35,121.36
1240028	Other Property - Retirement	(46,947.27)	0.00	0.00	0.00	0.00	(46,947.27)
	TOTAL NONUTILITY PLANT	**167,748.11**	**1,667.44**	**0.00**	**0.00**	**0.00**	**169,415.55**

U.S. Department of Energy Energy Information Administration Form EIA-826	**Monthly Electric Utility Sales and Revenue Report with State Distributions – 2025**	Form Approval OMB NO.1905-0129 (Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**

Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650.

Utility Name: Kentucky Power Company **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan___ Feb___ Mar_X__ Apr___ May___ Jun___ Jul___ Aug___ Sep___ Oct___ Nov___ Dec__ , 2025

Contact Person: Sandra Vargo **Phone number: 614-716-2671**

Email: slvargo@aep.com **Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	$ 27,984	$ 16,969	$ 14,575	$ -	$ 59,528
	b. Megwatthours	184,666	122,424	151,950	-	459,040
	c. Number of consumers	130,732	30,643	934	-	162,309
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					

Note:

KPSC Case No. 2025-00257
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May 29th, 2025

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed April 2025 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:	
1-12	Income Statement
1-3	Details of Operating Revenues
5-10	Operating Expenses – Functional Expenses
12	Detail Statement of Taxes
Balance Sheet:	
13	Balance Sheet – Assets & Other Debits
13-15	Balance Sheet – Liabilities & Other Credits
14-15	Deferred Credits
15	Statement of Retained Earnings
Utility Property:	
16-17	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Digitally signed by Brian J. Frantz
DN: cn=Brian J. Frantz, o=AEP, ou=Corporate Accounting, email=bjfrantz@aep.com
Reason: I have reviewed this document
Date: 2025.05.29 15:01:07 -04'00'

Brian J Frantz
Director - Corporate Accounting

American Electric Power

INCOME STATEMENT

IS8016
YTD Apr 2025
05/09/2025 11:15

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Apr 2025	Kentucky Power Company - Distribution 110 Actual YTD Apr 2025	Kentucky Power Company - Generation 117 Actual YTD Apr 2025	Kentucky Power Company - Transmission 180 Actual YTD Apr 2025
		REVENUES				
4400001		Residential Sales-W/Space Htg	63,973,663	65,201,836	(1,228,172)	0
4400002		Residential Sales-W/O Space Ht	24,333,065	25,274,148	(941,082)	0
4400005		Residential Fuel Rev	27,832,992	27,832,992	0	0
	A	**Revenue - Residential Sales**	**116,139,721**	**118,308,975**	**(2,169,255)**	**-**
4420001		Commercial Sales	34,391,064	35,507,946	(1,116,882)	0
4420006		Sales to Pub Auth - Schools	5,822,317	5,822,317	0	0
4420007		Sales to Pub Auth - Ex Schools	6,818,904	7,018,519	(199,615)	0
4420013		Commercial Fuel Rev	17,235,577	17,235,577	0	0
	A	**Revenue - Commercial Sales**	**64,267,862**	**65,584,359**	**(1,316,498)**	**-**
	B	**Revenue - Industrial Sales - Affiliated**	**-**	**-**	**-**	**-**
4420002		Industrial Sales (Excl Mines)	25,768,179	27,068,417	(1,300,238)	0
4420004		Ind Sales-NonAffil(Incl Mines)	5,826,864	5,826,864	0	0
4420016		Industrial Fuel Rev	22,971,739	22,971,739	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**54,566,782**	**55,867,020**	**(1,300,238)**	**-**
		Revenue - Industrial Sales	**54,566,782**	**55,867,020**	**(1,300,238)**	**-**
	A	**Revenue - Gas Products Sales**	**-**	**-**	**-**	**-**
	A	**Revenue - Gas Transportation & Storage Sales**	**-**	**-**	**-**	**-**
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	**-**	**-**	**-**	**-**
4440000		Public Street/Highway Lighting	627,481	631,110	(3,629)	0
4440002		Public St & Hwy Light Fuel Rev	107,122	107,122	0	0
	A	**Revenue - Other Retail Sales**	**734,603**	**738,232**	**(3,629)**	**-**
	B	**Revenue - Other Retail Sales - Affiliated**	**-**	**-**	**-**	**-**
		Revenue - Retail Sales	**235,708,967**	**240,498,586**	**(4,789,619)**	**-**
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	30,641,468
4561033		PJM NITS Revenue - Affiliated	29,167,390	0	0	29,167,390
4561034		PJM TO Adm. Serv Rev - Aff	65,374	0	0	65,374
4561035		PJM Affiliated Trans NITS Cost	(18,985,626)	0	(18,985,626)	0
4561036		PJM Affiliated Trans TO Cost	(34,790)	0	(34,790)	0
4561059		Affil PJM Trans Enhancmnt Rev	549,387	0	0	549,387
4561060		Affil PJM Trans Enhancmnt Cost	(357,607)	0	(357,607)	0
4561062		PROVISION RTO Tran Cost Affi	532,212	0	532,212	0
4561063		PROVISION RTO Tran Rev Aff	(109,556)	0	0	(109,556)
	B	**Revenue - Transmission-Affiliated**	**10,826,784**	**-**	**(18,845,811)**	**60,314,063**
4470150		Transm. Rev.-Dedic. Whlsl/Muni	(6,964)	0	(854,595)	847,631
4470206		PJM Trans loss credits-OSS	46,274	0	46,274	0
4470209		PJM transm loss charges-OSS	(72,253)	0	(72,253)	0
4561005		PJM Point to Point Trans Svc	880,485	0	880,485	0
4561006		PJM Trans Owner Admin Rev	32,137	0	0	32,137
4561007		PJM Network Integ Trans Svc	3,922,710	0	0	3,922,710
4561019		Oth Elec Rev Trans Non Affil	20,402	0	0	20,402
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	444	0	0	444
4561029		PJM NITS Revenue Whsl Cus-NAff	991,059	0	0	991,059
4561030		PJM TO Serv Rev Whls Cus-NAff	2,302	0	0	2,302
4561045		PJM Non-Aff Gen IPP Rev	7,976	0	0	7,976
4561058		NonAffil PJM Trans Enhncmt Rev	630,788	0	0	630,788
4561061		NAff PJM RTEP Rev for Whsl-FR	18,667	0	0	18,667
4561064		PROVISION RTO Tran Rv Frml Rts	(3,680)	0	0	(3,680)
4561065		PROVISION RTO Tran Rev NonAff	(16,460)	0	0	(16,460)
	A	**Revenue - Transmission-NonAffiliated**	**6,453,887**	**-**	**(89)**	**6,453,975**
		Revenue - Transmission	**17,280,671**	**-**	**(18,845,899)**	**66,768,039**

KPSC Case No. 2025-00257
Application - Section II
Filing Requirements
Exhibit R
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American Electric Power

INCOME STATEMENT

IS8016 YTD Apr 2025 05/09/2025 11:15			Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
		Layout: IS8016				
17A V2099-01-01		Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025
	B	**Revenue - Resale-Affiliated**	-	-	-	-
4470027		Whsal/Muni/Pb Ath Fuel Rev	1,224,389	0	1,224,389	0
4470033		Whsal/Muni/Pub Auth Base Rev	808,801	0	808,801	0
4470082		Financial Electric Realized	(1,868)	0	(1,868)	0
4470089		PJM Energy Sales Margin	261,853	0	261,853	0
4470098		PJM Oper.Reserve Rev-OSS	(25,916)	0	(25,916)	0
4470099		Capacity Cr. Net Sales	(40,435)	0	(40,435)	0
4470100		PJM FTR Revenue-OSS	47,047	0	47,047	0
4470103		PJM Energy Sales Cost	4,062,883	0	4,062,883	0
4470115		PJM Meter Corrections-OSS	(9,970)	0	(9,970)	0
4470116		PJM Meter Corrections-LSE	(166,313)	0	(166,313)	0
4470126		PJM Incremental Imp Cong-OSS	(42,505)	0	(42,505)	0
4470175		OSS Sharing Reclass - Retail	2,170,714	0	2,170,714	0
4470176		OSS Sharing Reclass-Reduction	(2,170,714)	0	(2,170,714)	0
4470220		PJM Regulation - OSS	1,987,480	0	1,987,480	0
4470221		PJM Spinning Reserve - OSS	42,058	0	42,058	0
5550080		PJM Hourly Net Purch.-FERC	(2,124,034)	0	(2,124,034)	0
	A	**Revenue - Resale-NonAffiliated**	**6,023,470**	**-**	**6,023,470**	**-**
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**6,023,470**	**-**	**6,023,470**	**-**
4470074		Sale for Resale-Aff-Trnf Price	0	0	156,417,397	0
4540001		Rent From Elect Property - Af	633,189	389,004	0	380,199
	B	**Revenue - Other Ele-Affilliated**	**633,189**	**389,004**	**156,417,397**	**380,199**
4500000		Forfeited Discounts	436,718	436,718	0	0
4510001		Misc Service Rev - Nonaffil	27,296	27,222	0	74
4540002		Rent From Elect Property-NAC	1,004,167	700	984,192	19,275
4540005		Rent from Elec Prop-Pole Attch	1,578,829	1,575,979	0	2,850
4560007		Oth Elect Rev - DSM Program	315,627	315,627	0	0
5010040		Gas Procuremnt Sales Net	(233,801)	0	(233,801)	0
		Revenue - Other Ele-NonAffilliated	**3,128,835**	**2,356,246**	**750,391**	**22,199**
		Revenue - Gas	-	-	-	-
4118002		Comp. Allow Gains Title IV SO2	7	7	0	0
		Gain/(Loss) on Allowances	**7**	**7**	**-**	**-**
	A	**Revenue - Other Ele-NonAffilliated**	**3,128,843**	**2,356,253**	**750,391**	**22,199**
		Revenue - Other Opr Electric	**3,762,032**	**2,745,257**	**157,167,788**	**402,398**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
4170004		Rev from Non-Util Oper NonAfil	108,564	108,564	0	0
	D	**Revenues Non-Utility Operations - NonAffiliated**	**108,564**	**108,564**	**-**	**-**
		Revenues from Non-Utility Operations	**108,564**	**108,564**	**-**	**-**
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operatng Rental Income	400	400	0	0
4180005		Non-Opratng Rntal Inc-Depr	(2,223)	0	0	(2,223)
	D	**Non-Operating Rental Income - NonAffiliated**	**(1,823)**	**400**	**-**	**(2,223)**
		Non-Operating Rental Income	**(1,823)**	**400**	**-**	**(2,223)**
	C	**Non-Operating Misc Income -Affiliated**	-	-	-	-
4210002		Misc Non-Op Inc-NonAsc-Rents	385	0	385	0
4210007		Misc Non-Op Inc - NonAsc - Oth	334	302	32	0
	D	**Non-Operating Misc Income - NonAffiliated**	**718**	**302**	**417**	**-**

American Electric Power

INCOME STATEMENT

IS8016
YTD Apr 2025
05/09/2025 11:15

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD Apr 2025	Kentucky Power Company - Distribution 110 Actual YTD Apr 2025	Kentucky Power Company - Generation 117 Actual YTD Apr 2025	Kentucky Power Company - Transmission 180 Actual YTD Apr 2025
		Non-Operating Misc Income	**718**	**302**	**417**	**-**
4560015		Other Electric Revenues - ABD	152,845	152,845	0	0
	D	**Associated Business Development Income**	**152,845**	**152,845**	**-**	**-**
		Revenue - Other Opr - Other	**260,304**	**262,110**	**417**	**(2,223)**
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	**-**	**-**	**-**	**-**
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***260,304***	***262,110***	***417***	***(2,223)***
		Revenue - Other Operating	**4,022,335**	**3,007,367**	**157,168,204**	**400,175**
4491005		Tran Prov Trans Ref NonAffil	(80,394)	0	0	(80,394)
4491006		Tran Prov Trans Ref Frml Rate	(18,178)	0	0	(18,178)
	A	**Provision for Rate Refund - NonAffiliated**	**(98,572)**	**-**	**-**	**(98,572)**
4491007		Trans Prov Trans Refunds Affil	(537,711)	0	0	(537,711)
	B	**Provision for Rate Refund - Affiliated**	**(537,711)**	**-**	**-**	**(537,711)**
		Provision for Rate Refund	**(636,283)**	**-**	**-**	**(636,283)**
	A	**Revenue - Power Sales**	**-**	**-**	**-**	**-**
		TOTAL OPERATING REVENUES	**262,399,161**	**243,505,953**	**139,556,156**	**66,531,931**
	=(A)	*Memo: G/T/D Revenue*	*251,216,594*	*242,854,839*	*1,984,153*	*6,377,602*
	=(B)	*Memo: Other Affiliated Revenue*	*10,922,262*	*389,004*	*137,571,586*	*60,156,552*
	=(C)	*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
	=(D)	*Memo: Revenue-Oth Opr-Oth Non*	*260,304*	*262,110*	*417*	*(2,223)*
		Memo: Total Operating Revenues	*262,399,161*	*243,505,953*	*139,556,156*	*66,531,931*
	=(E)=(B)+(C)	*Memo: Affiliated Revenue*	***10,922,262***	***389,004***	***137,571,586***	***60,156,552***
	=(F)=(D)+(A)	*Memo: Non-Affiliated Revenue*	***251,476,898***	***243,116,949***	***1,984,570***	***6,375,379***
		Memo: Total Operating Revenues	***262,399,161***	***243,505,953***	***139,556,156***	***66,531,931***
		FUEL EXPENSES				
5010000		Fuel	3,124,507	0	3,124,507	0
5010001		Fuel Consumed	22,161,229	0	22,161,229	0
5010003		Fuel - Procure Unload & Handle	1,167,879	0	1,167,879	0
5010012		Ash Sales Proceeds	1,978	0	1,978	0
5010019		Fuel Oil Consumed	1,202,646	0	1,202,646	0
5010020		Nat Gas Consumed Steam	14,869,389	0	14,869,389	0
5010021		Transp Gas Consumed Steam	153,498	0	153,498	0
5010027		Gypsum handling/disposal costs	473,925	0	473,925	0
5010028		Gypsum Sales Proceeds	(454,696)	0	(454,696)	0
5010034		Gas Transp Res Fees-Steam	2,153,339	0	2,153,339	0
		Fuel Expense Total	**44,853,694**	**-**	**44,853,694**	**-**
5010005		Fuel - Deferred	478,066	0	478,066	0
		Deferred Fuel Expense	**478,066**	**-**	**478,066**	**-**
		Over Under Fuel Expense				
		Fuel for Electric Generation	**45,331,759**	**-**	**45,331,759**	**-**
		Fuel from Affiliates for Electric Generation	**-**	**-**	**-**	**-**
5090000		Allow Consum Title IV SO2	6,199	0	6,199	0
5090009		Allow Consumpt CSAPR SO2	30	0	30	0
		Allowances - Consumption	**6,229**	**-**	**6,229**	**-**
5020002		Urea Expense	306,265	0	306,265	0
5020004		Lime-Related Expenses	631,586	0	631,586	0
		Emissions Control - Chemicals	**937,851**	**-**	**937,851**	**-**
		Total Fuel for Electric Generation	**46,275,840**	**-**	**46,275,840**	**-**
		Memo: NonAff Fuel/Allow/Emissions	***46,275,840***	**-**	***46,275,840***	**-**
5550029		Purch Power-Assoc-Trnsfr Price	0	156,417,397	0	0

KPSC Case No. 2025-00257
Application - Section II
Filing Requirements
Exhibit R
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American Electric Power

INCOME STATEMENT

IS8016
YTD Apr 2025
05/09/2025 11:15

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Apr 2025	Kentucky Power Company - Distribution 110 Actual YTD Apr 2025	Kentucky Power Company - Generation 117 Actual YTD Apr 2025	Kentucky Power Company - Transmission 180 Actual YTD Apr 2025
	Purchased Electricity from AEP - Affiliates	**-**	**156,417,397**	**-**	**-**
5550001	Purch Pwr-NonTrading-Nonassoc	51,420,549	0	51,420,549	0
5550023	Purch Power Capacity -NA	806,194	0	806,194	0
5550039	PJM Inadvertent Mtr Res-OSS	(1,617)	0	(1,617)	0
5550040	PJM Inadvertent Mtr Res-LSE	(24,999)	0	(24,999)	0
5550074	PJM Reactive-Charge	1,103,818	0	1,103,818	0
5550075	PJM Reactive-Credit	(478,292)	0	(478,292)	0
5550076	PJM Black Start-Charge	144,250	0	144,250	0
5550078	PJM Regulation-Charge	349,918	0	349,918	0
5550079	PJM Regulation-Credit	212,643	0	212,643	0
5550083	PJM Sync & Non Sync-Charge	385,734	0	385,734	0
5550084	PJM Sync & Non Sync-Credit	(71,663)	0	(71,663)	0
5550123	PJM OpRes-LSE-Charge	3,508,099	0	3,508,099	0
5550124	PJM Implicit Congestion-LSE	3,103,403	0	3,103,403	0
5550132	PJM FTR Revenue-LSE	(5,395,323)	0	(5,395,323)	0
5550137	PJM OpRes-LSE-Credit	(18,586)	0	(18,586)	0
5550326	PJM Transm Loss Charges - LSE	2,772,872	0	2,772,872	0
5550327	PJM Transm Loss Credits-LSE	(1,431,326)	0	(1,431,326)	0
5550328	PJM FC Penalty Credit	(1,969)	0	(1,969)	0
	Purchased Electricity for Resale - NonAffiliated	**56,383,706**	**-**	**56,383,705**	**0**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**
	Purchased Gas for Resale - NonAffiliated	**-**	**-**	**-**	**-**
	Total Purchased Power	**56,383,706**	**156,417,397**	**56,383,705**	**0**
	GROSS MARGIN	**159,739,615**	**87,088,556**	**36,896,611**	**66,531,930**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	1,306,410	6,155	1,296,818	3,436
5020000	Steam Expenses	679,056	0	679,056	0
5050000	Electric Expenses	19,391	0	19,391	0
5060000	Misc Steam Power Expenses	1,525,965	(19,112)	1,534,197	10,880
5060002	Misc Steam Power Exp-Assoc	19,046	0	19,046	0
5070006	Rents - Associated	773	0	773	0
	Steam Generation Op Exp	**3,550,641**	**(12,957)**	**3,549,281**	**14,316**
	Nuclear Generation Op Exp	**-**	**-**	**-**	**-**
5390000	Misc Hydr Power Generation Exp	(0)	0	0	0
	Hydro Generation Op Exp	**(0)**	**-**	**-**	**-**
5560000	Sys Control & Load Dispatching	17,196	0	17,196	0
5570000	Other Expenses	252,425	0	252,425	0
5570007	Other Pwr Exp - Wholesale RECs	243	243	0	0
5570025	MATL-SAFETY	1	0	0	1
5581000	Oper Supervision & Engineering	25	0	25	0
5581300	Oper Supervision & Engineering	236	0	236	0
5581400	Wind Turb Gen&Oth Plnt Op-Mjr	1,199	306	603	291
5582000	Solar Panel Gen&Oth Plt Op-Mjr	2	0	2	0
5757000	PJM Admin-MAM&SC- OSS	20,558	0	20,558	0
5757001	PJM Admin-MAM&SC- Internal	490,512	0	490,512	0
5775000	Oper Supplies and Expense NMjr	13	0	0	13
	Other Generation Op Exp	**782,411**	**549**	**781,557**	**304**
5600000	Oper Supervision & Engineering	778,973	16,642	6,207	756,123
5612000	Load Dispatch-Mntr&Op TransSys	212,074	1,693	236	210,145
5613000	Load Dispatch-Trans Srvc&Sched	107	0	0	107

American Electric Power

INCOME STATEMENT

IS8016 YTD Apr 2025 05/09/2025 11:15		Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025
5614000	PJM Admin-SSC&DS-OSS	25,113	0	25,113	0
5614001	PJM Admin-SSC&DS-Internal	526,779	0	526,779	0
5615000	Reliability,Plng&Stds Develop	32,145	424	59	31,662
5618000	PJM Admin-RP&SDS-OSS	8,338	0	8,338	0
5618001	PJM Admin-RP&SDS- Internal	162,510	0	162,510	0
5620001	Station Expenses - Nonassoc	102,245	6,897	0	95,348
5630000	Overhead Line Expenses	4,195	3	1	4,191
5650002	Transmssn Elec by Others-NAC	38,631	0	38,631	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	30,641,468	0	0
5650012	PJM Trans Enhancement Charge	689,452	0	689,452	0
5650015	PJM TO Serv Exp - Aff	59,573	0	59,573	0
5650016	PJM NITS Expense - Affiliated	25,163,317	0	25,163,317	0
5650019	Affil PJM Trans Enhncement Exp	1,595,403	0	1,595,403	0
5650020	PROVISION RTO Affl Tran Expnse	(471,041)	0	(471,041)	0
5650021	PJM NITS Expense - Non-Affilia	376,915	0	376,915	0
5650023	Amort of PROVISION RTO Expense	3,175,808	0	3,175,808	0
5660000	Misc Transmission Expenses	246,640	(50,434)	1,690	295,383
5660011	Misc Transm Exp - Affiliate	1,187	0	0	1,187
5670001	Rents - Nonassociated	250	0	0	250
5670002	Rents - Associated	0	0	0	136,014
	Transmission Op Exp	**32,728,614**	**30,616,694**	**31,358,992**	**1,530,411**
5800000	Oper Supervision & Engineering	568,086	563,685	312	4,105
5810000	Load Dispatching	726	726	0	0
5820000	Station Expenses	113,292	109,314	2	3,975
5830000	Overhead Line Expenses	464,824	464,918	(0)	80
5840000	Underground Line Expenses	138,293	138,298	0	(5)
5850000	Street Lighting & Signal Sys E	3,918	3,919	0	0
5860000	Meter Expenses	389,767	389,959	3	129
5870000	Customer Installations Exp	54,749	54,698	20	59
5880000	Miscellaneous Distribution Exp	926,513	921,294	397	5,137
5890001	Rents - Nonassociated	381,593	381,593	0	0
5890002	Rents - Associated	4,126	4,126	0	0
	Distribution Op Exp	**3,045,886**	**3,032,531**	**734**	**13,480**
9010000	Supervision - Customer Accts	8,407	8,419	(3)	(9)
9020000	Meter Reading Expenses	21,633	21,633	0	0
9020002	Meter Reading - Regular	128,040	128,104	0	0
9020003	Meter Reading - Large Power	10,251	10,251	0	0
9030000	Cust Records & Collection Exp	121,109	118,416	103	2,590
9030001	Customer Orders & Inquiries	913,033	912,757	75	213
9030002	Manual Billing	2,624	2,624	0	0
9030003	Postage - Customer Bills	212,454	212,454	0	0
9030004	Cashiering	18,274	18,274	0	0
9030005	Collection Agents Fees & Exp	1,250	1,250	0	0
9030006	Credit & Oth Collection Activi	132,830	132,713	20	150
9030007	Collectors	102,538	102,538	0	0
9030009	Data Processing	(315)	(315)	0	0
9040007	Uncoll Accts - Misc Receivable	(1,934)	(1,934)	0	0
9050000	Misc Customer Accounts Exp	11,026	11,026	0	0
9070000	Supervision - Customer Service	6,342	6,343	0	(1)
9070001	Supervision - DSM	19	17	2	0
9080000	Customer Assistance Expenses	398,924	398,927	2	9

American Electric Power

INCOME STATEMENT

IS8016
YTD Apr 2025
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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Apr 2025	Kentucky Power Company - Distribution 110 Actual YTD Apr 2025	Kentucky Power Company - Generation 117 Actual YTD Apr 2025	Kentucky Power Company - Transmission 180 Actual YTD Apr 2025
9080009	Cust Assistance Expense - DSM	266,860	266,860	0	0
9100000	Misc Cust Svc&Informational Ex	11,931	5,806	3,076	3,049
9100001	Misc Cust Svc & Info Exp - RCS	(98)	(52)	0	(46)
	Customer Service and Information Op Exp	**2,365,200**	**2,356,111**	**3,274**	**5,956**
9120000	Demonstrating & Selling Exp	2,407	2,407	0	0
9120003	Demo & Selling Exp - Area Dev	32	32	0	0
	Sales Expenses	**2,439**	**2,439**	**-**	**-**
	Memo: Insurance (9240 9250)	**866,718**	**411,271**	**357,011**	**98,436**
9200000	Administrative & Gen Salaries	4,040,024	2,107,987	1,285,719	646,322
9210001	Off Supl & Exp - Nonassociated	491,725	317,698	131,936	42,158
9210003	Office Supplies & Exp - Trnsf	64	22	29	13
9210021	EMP TRAVEL - Airfare	216	99	87	31
9210022	MEALS & ENT-100 Pct DEDUCTIBLE	66	34	25	7
9210023	EMP TRAVEL-MILEAGE	134	88	43	3
9210024	EMP TRAVEL-PARKING	48	28	17	3
9210025	MEALS & ENT-50 Pct DEDUCTIBLE	36	24	11	1
9210026	EMP TRAVEL-CAR RENTAL	17	9	6	1
9210027	EMP TRAVEL-TAXI AND SHUTTLE	25	12	10	3
9210028	EMP TRAVEL-HOTEL & LODGING	323	174	119	30
9210030	EMP TRAVEL-OTHER	59	20	26	12
9210032	FUEL	3	2	1	0
9210033	FOOD SERVICE-CATERING	40	13	18	8
9210034	In-House Training & Seminars	265	126	57	82
9210037	OEM/TECHNICAL TRAINING	317	0	317	0
9210040	DUES-BUSINESS/PROFESSIONAL	81	28	37	17
9210041	VEHICLE-LICENSE FEES	10	3	4	2
9220000	Administrative Exp Trnsf - Cr	(74,111)	(73,736)	0	(375)
9220001	Admin Exp Trnsf to Cnstrction	(147,776)	(147,776)	0	0
9220002	Admin Exp Trnsf Const-Mngerial	0	0	0	0
9220004	Admin Exp Trnsf to ABD	(230)	(230)	0	0
9220005	Overhead Loadings	(213,388)	(159,659)	(41,249)	(12,481)
9230001	Outside Svcs Empl - Nonassoc	742,454	147,735	307,846	286,872
9230003	AEPSC Billed to Client Co	(175,566)	(67,103)	(82,475)	(25,988)
9230031	SRV-OUTSIDE SERVICES (TECH)	112	38	51	24
9230034	SRV-SOFTWARE LICENSING	5,586	3,980	1,144	462
9230064	Def AEPSC Pension Settlement	3,464	1,242	1,108	1,114
9240000	Property Insurance	356,672	89,988	203,824	62,860
9250000	Injuries and Damages	641,895	443,033	163,715	35,147
9250002	Emp Accdent Prvntion-Adm Exp	(95)	(32)	(34)	(29)
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	(69,032)	(63,842)	(6,060)	871
9250007	Prsnal Injries&Prop Dmage-Pub	1,546	0	1,546	0
9250010	Frg Ben Loading - Workers Comp	(64,268)	(57,876)	(5,980)	(413)
9260000	Employee Pensions & Benefits	774	774	0	0
9260002	Pension & Group Ins Admin	8,652	3,968	4,551	133
9260003	Pension Plan	691,283	462,108	223,435	5,740
9260004	Group Life Insurance Premiums	45,946	30,230	15,360	356
9260005	Group Medical Ins Premiums	1,849,018	1,276,560	550,727	21,731
9260007	Group L-T Disability Ins Prem	145,476	84,056	61,219	201
9260009	Group Dental Insurance Prem	58,608	40,291	17,560	757
9260010	Training Administration Exp	396	213	139	45
9260012	Employee Activities	3,594	2,916	646	33

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INCOME STATEMENT

IS8016
YTD Apr 2025
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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD Apr 2025	Kentucky Power Company - Distribution 110 Actual YTD Apr 2025	Kentucky Power Company - Generation 117 Actual YTD Apr 2025	Kentucky Power Company - Transmission 180 Actual YTD Apr 2025
9260021	Postretirement Benefits - OPEB	25,187	14,086	10,695	406
9260027	Savings Plan Contributions	606,203	411,458	190,025	4,721
9260036	Deferred Compensation	9,525	9,525	0	0
9260037	Supplemental Pension	2,172	1,859	313	0
9260050	Frg Ben Loading - Pension	(295,344)	(255,360)	(33,858)	(6,127)
9260051	Frg Ben Loading - Grp Ins	(813,403)	(703,991)	(93,508)	(15,904)
9260052	Frg Ben Loading - Savings	(238,713)	(203,497)	(30,578)	(4,638)
9260053	Frg Ben Loading - OPEB	(12,868)	(9,734)	(2,640)	(493)
9260055	IntercoFringeOffset- Don't Use	(151,871)	(151,871)	0	0
9260058	Frg Ben Loading - Accrual	(141,895)	(135,020)	(1,415)	(5,459)
9270000	Franchise Requirements	53,471	53,471	0	0
9280000	Regulatory Commission Exp	9,061	3,900	2,708	2,454
9280002	Regulatory Commission Exp-Case	424,018	156,527	130,214	137,277
9280005	Reg Com Exp-FERC Trans Cases	32,228	27,398	389	4,441
9280006	State Publ Serv CommissionFees	317,732	317,732	0	0
9301000	General Advertising Expenses	7,575	6,142	714	719
9301001	Newspaper Advertising Space	1,811	804	506	501
9301003	TV Station Advertising Time	890	396	250	244
9301006	Spec Corporate Comm Info Proj	1,137	1,137	0	0
9301007	Special Adv Space & Prod Exp	750	750	0	0
9301012	Public Opinion Surveys	9,142	9,142	0	0
9301015	Other Corporate Comm Exp	923	923	0	0
9302000	Misc General Expenses	80,610	(6,060)	52,868	33,802
9302003	Corporate & Fiscal Expenses	26,966	17,884	7,295	1,787
9302004	Research, Develop&Demonstr Exp	18	18	0	0
9310001	Rents - Real Property	3,200	3,200	0	0
9310002	Rents - Personal Property	16,672	14,239	2,275	169
	Administration & General	**8,319,666**	**4,028,304**	**3,071,789**	**1,219,655**
4111005	Accretion Expense	773,944	6,279	767,665	0
	Accretion	**773,944**	**6,279**	**767,665**	**-**
4116000	Gain From Disposition of Plant	(5,506)	(5,506)	0	0
	Loss/(Gain) on Utility Plant	**(5,506)**	**(5,506)**	**-**	**-**
9302006	Assoc Bus Dev - Materials Sold	13,312	13,299	0	13
9302007	Assoc Business Development Exp	74,272	65,691	107	8,482
	Associated Business Development Expenses	**87,584**	**78,991**	**107**	**8,495**
4211000	Gain on Dspsition of Property	(53)	0	0	(53)
	Gain on Disposition of Property	**(53)**	**-**	**-**	**(53)**
	Loss on Disposition of Property	**-**	**-**	**-**	**-**
	Loss(Gain) of Sale of Property	**(53)**	**-**	**-**	**(53)**
4265009	Factored Cust A/R Exp - Affil	1,167,300	1,167,300	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	369,332	369,332	0	0
	Opr Exp and Factored A/R	**1,536,632**	**1,536,632**	**-**	**-**
	Water Heaters	**-**	**-**	**-**	**-**
4030047	Depr Exp - Cloud Computing	184,683	129,142	31,904	23,636
4265004	Social & Service Club Dues	38,067	665	37,402	0
4265007	Regulatory Expenses	1,320	585	372	363
	Expense of Non-Utility Operation	**224,069**	**130,392**	**69,678**	**23,999**
4210009	Misc Non-Op Exp - NonAssoc	489	234	114	142
	Misc NonOp Expenses - NonAssoc	**489**	**234**	**114**	**142**
4261000	Donations	562,012	558,409	1,519	2,084

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Filing Requirements
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IS8016 YTD Apr 2025 05/09/2025 11:15	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025
	Donation Contributions	**562,012**	**558,409**	**1,519**	**2,084**
4263001	Penalties	1	1	1	0
	Provision for Penalties	**1**	**1**	**1**	**0**
4264000	Civic and Political Activity	48,422	21,851	13,407	13,166
4264001	Non-deduct Lobbying per IRS	13,497	4,057	6,867	2,573
	Civic & Political Activities	**61,919**	**25,908**	**20,275**	**15,739**
4265002	Other Deductions - Nonassoc	347,786	19,258	316,341	12,187
	Other Deductions	**347,786**	**19,258**	**316,341**	**12,187**
	Shutdown Coal Company Expenses	**-**	**-**	**-**	**-**
	All Other Operational Expenses	**2,732,909**	**2,270,833**	**407,927**	**54,151**
	Operational Expenses	**54,383,732**	**42,374,268**	**39,941,326**	**2,846,715**
5100000	Maint Supv & Engineering	361,409	0	361,409	0
5110000	Maintenance of Structures	583,224	0	583,224	0
5120000	Maintenance of Boiler Plant	6,134,423	0	6,134,423	0
5120034	BSDR O/U Recovery - Maint Cost	(2,396)	0	(2,396)	0
5120037	KY Steam Maint O/U	(233,084)	0	(233,084)	0
5130000	Maintenance of Electric Plant	2,100,448	0	2,100,448	0
5132000	Maint of Computer Software-Mjr	23,153	0	23,153	0
5133000	Maint of Comm Equipmt-Mjr	640	0	640	0
5140000	Maintenance of Misc Steam Plt	587,083	0	587,083	0
	Steam Generation Maintenance	**9,554,900**	**-**	**9,554,899**	**0**
5312000	Maint of Computer Software	15	8	1	6
	Nuclear Generation Maintenance	**15**	**8**	**1**	**6**
	Hydro Generation Maintenance	**-**	**-**	**-**	**-**
5587000	Maint Solar Pnl Strct & Eq-Mjr	8	2	5	2
	Other Generation Maintenance	**8**	**2**	**5**	**2**
5680000	Maint Supv & Engineering	4,205	77	358	3,771
5690000	Maintenance of Structures	18,392	0	0	18,392
5691000	Maint of Computer Hardware	1,275	118	45	1,112
5692000	Maint of Computer Software	39,083	5	51	39,027
5693000	Maint of Communication Equip	2,523	103	0	2,420
5700000	Maint of Station Equipment	258,939	(74)	(0)	259,013
5710000	Maintenance of Overhead Lines	1,744,016	0	0	1,744,021
5720000	Maint of Underground Lines	108	0	0	108
5730000	Maint of Misc Trnsmssion Plt	4,981	0	0	4,981
	Transmission Maintenance	**2,073,523**	**229**	**454**	**2,072,844**
5900000	Maint Supv & Engineering	33,439	33,448	0	(5)
5910000	Maintenance of Structures	7,704	7,658	0	46
5920000	Maint of Station Equipment	163,719	156,143	64	7,512
5923000	Maint of Computer Software-Mjr	34,756	34,756	0	0
5924000	Maint of Comm Equipmt-Mjr	275,280	275,280	0	0
5930000	Maintenance of Overhead Lines	12,212,279	12,314,895	41	(98,933)
5930001	Tree and Brush Control	122,925	122,988	0	0
5940000	Maint of Underground Lines	19,959	19,951	0	13
5950000	Maint of Lne Trnf,Rglators&Dvi	1,534	1,534	1	0
5960000	Maint of Strt Lghtng & Sgnal S	1,966	1,966	0	0
5970000	Maintenance of Meters	13,611	13,620	0	0
5980000	Maint of Misc Distribution Plt	6,046	6,000	1	45
	Distribution Maintenance	**12,893,216**	**12,988,239**	**107**	**(91,323)**
9350000	Maintenance of General Plant	2,402	2,401	1	0
9350001	Maint of Structures - Owned	73,369	71,599	838	931

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IS8016 YTD Apr 2025 05/09/2025 11:15	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025
9350002	Maint of Structures - Leased	4,148	1,430	131	2,587
9350013	Maint of Cmmncation Eq-Unall	(248)	0	0	0
9351000	Maint of Computer Hardware	1,680	1,203	401	76
9352000	Maint of Computer Software	259,599	92,053	147,587	19,960
9353000	Maint of Comm Equipmt	50,223	41,471	8,441	311
	Administration & General Maintenance	**391,173**	**210,156**	**157,400**	**23,865**
	All Other Maintenance Expenses	**-**	**-**	**-**	**-**
	Maintenance Expenses	**24,912,835**	**13,198,634**	**9,712,866**	**2,005,394**
	Total Operational and Maintenance Expenses	**79,296,567**	**55,572,902**	**49,654,192**	**4,852,110**
4030046	Capitalized Software Depr Exp	2,888,286	1,518,051	881,561	488,674
4040001	Amort. of Plant	133,471	34,148	75,986	23,337
4060001	Amort of Plt Acq Adj	12,872	0	0	12,872
	DDA Amortization	**3,034,629**	**1,552,199**	**957,547**	**524,883**
4073014	Regulatory Debit - BSDR	69,320	0	69,320	0
	DDA Regulatory Debits	**69,320**	**-**	**69,320**	**-**
4074000	Regulatory Credits	(162,725)	(162,725)	0	0
4074025	PPA RIDER Over/Under	1,737,404	0	1,737,404	0
	DDA Regulatory Credits	**1,574,679**	**(162,725)**	**1,737,404**	**-**
	Amortization	**4,678,627**	**1,389,474**	**2,764,270**	**524,883**
4030001	Depreciation Exp	36,951,529	15,709,431	12,260,639	8,981,460
4030029	Over/Undr Depr Exp Var Riders	190,775	0	190,775	0
	DDA Depreciation	**37,142,304**	**15,709,431**	**12,451,414**	**8,981,460**
	DDA STP Nuclear Decommissioning	**-**	**-**	**-**	**-**
4031001	Depr - Asset Retirement Oblig	636,802	3,424	633,378	0
	DDA Asset Retirement Obligation	**636,802**	**3,424**	**633,378**	**-**
	DDA Removal Costs	**-**	**-**	**-**	**-**
	Depreciation	**37,779,106**	**15,712,855**	**13,084,792**	**8,981,460**
	Depreciation and Amortization	**42,457,733**	**17,102,329**	**15,849,062**	**9,506,343**
	Franchise Taxes	**-**	**-**	**-**	**-**
408100624	State Gross Receipts Tax	126	0	0	126
408100625	State Gross Receipts Tax	6,165	0	6,165	0
	Revenue-kWhr Taxes	**6,291**	**-**	**6,165**	**126**
4081002	FICA	1,194,806	840,763	344,471	9,573
4081003	Federal Unemployment Tax	11,416	6,971	4,318	127
4081007	State Unemployment Tax	20,317	6,971	13,226	120
4081033	Fringe Benefit Loading - FICA	(449,638)	(383,789)	(57,212)	(8,637)
4081034	Fringe Benefit Loading - FUT	(2,257)	(1,967)	(234)	(56)
4081035	Fringe Benefit Loading - SUT	(2,495)	(1,677)	(802)	(17)
	Payroll Taxes	**772,149**	**467,272**	**303,768**	**1,110**
408102021	State Business Occup Taxes	(224,843)	0	(224,843)	0
408102022	State Business Occup Taxes	(449,687)	0	(449,687)	0
408102023	State Business Occup Taxes	(534,125)	0	(534,125)	0
408102024	State Business Occup Taxes	(550,825)	0	(550,825)	0
408102025	State Business Occup Taxes	2,348,626	0	2,348,626	0
	Capacity Taxes	**589,146**	**-**	**589,146**	**-**
408100523	Real Personal Property Taxes	1,050,088	0	1,050,088	0
408100524	Real Personal Property Taxes	4,994,800	2,825,776	485,388	1,683,636
408102925	Real-Pers Prop Tax-Cap Leases	220,768	208,536	7,040	5,192
408103625	Real Prop Tax-Cap Leases	5,000	5,000	0	0

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IS8016 YTD Apr 2025 05/09/2025 11:15	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025
408200524	Real Personal Property Taxes	40,468	1,242	22,529	16,697
	Property Taxes	**6,311,124**	**3,040,554**	**1,565,045**	**1,705,525**
	Regulatory Fees	**-**	**-**	**-**	**-**
408101424	Federal Excise Taxes	1,073	0	1,073	0
408101425	Federal Excise Taxes	872	0	872	0
	Production Taxes	**1,945**	**-**	**1,945**	**-**
408101924	State Sales and Use Taxes	1,795	1,795	0	0
408101925	State Sales and Use Taxes	18,617	6,286	12,331	0
	Miscellaneous Taxes	**20,411**	**8,080**	**12,331**	**-**
	Other Non-Income Taxes	**22,356**	**8,080**	**14,276**	**-**
	Taxes Other Than Income Taxes	**7,701,067**	**3,515,906**	**2,478,400**	**1,706,761**
	TOTAL OPERATING EXPENSES	**129,455,367**	**76,191,137**	**67,981,654**	**16,065,213**
	Memo: SEC Total Operating Expenses	**232,114,913**	**232,608,533**	**170,641,200**	**16,065,214**
	OPERATING INCOME	**30,284,248**	**10,897,420**	**(31,085,043)**	**50,466,717**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	57,584	1,179	56,405	0
	Interest & Dividend NonAffiliated	**57,584**	**1,179**	**56,405**	**-**
4190005	Interest Income - Assoc CBP	137	137	0	0
	Interest & Dividend Affiliated	**137**	**137**	**-**	**-**
	Total Interest & Dividend Income	**57,721**	**1,316**	**56,405**	**-**
	Interest & Dividend Carrying Charge	**-**	**-**	**-**	**-**
	Memo: Total Interest & Dividend Income w/ Carrying	**57,721**	**1,316**	**56,405**	**-**
9260042	SERP Pension - Non-Service	(2,018)	(1,768)	(250)	0
9260043	OPEB - Non-Service	959,604	400,806	539,257	19,542
9260062	Pension Plan - Non-Service	837,613	84,803	785,756	(32,946)
9260064	Def AEPSC Pension Settlement	(476)	(184)	(292)	0
	Other Components of Net Periodic Pension	**1,794,723**	**483,657**	**1,324,470**	**(13,405)**
4191000	Allw Oth Fnds Usd Drng Cnstr	812,716	248,269	38,000	526,447
	AFUDC	**812,716**	**248,269**	**38,000**	**526,447**
	Gain on Disposition of Equity Investments	**-**	**-**	**-**	**-**
	Interest LTD FMB	**-**	**-**	**-**	**-**
4270002	Int on LTD - Install Pur Contr	(1,018,333)	(1,018,333)	0	0
	Interest LTD IPC	**(1,018,333)**	**(1,018,333)**	**-**	**-**
	Interest LTD Notes Payable - Affiliated	**-**	**-**	**-**	**-**
	Interest LTD Notes Payable - NonAffiliated	**-**	**-**	**-**	**-**
	Interest LTD Debentures	**-**	**-**	**-**	**-**
4270006	Int on LTD - Sen Unsec Notes	(18,511,417)	(18,511,417)	0	0
	Interest LTD Senior Unsecured	**(18,511,417)**	**(18,511,417)**	**-**	**-**
	Interest LTD Other - Affil	**-**	**-**	**-**	**-**
4270005	Int on LTD - Other LTD	(5,317,085)	(5,317,085)	0	0
	Interest LTD Other - NonAffil	**(5,317,085)**	**(5,317,085)**	**-**	**-**
	Interest on Long-Term Debt	**(24,846,835)**	**(24,846,835)**	**-**	**-**
4300003	Int to Assoc Co - CBP	(707,879)	11,776,988	(16,752,888)	4,268,022
	Interest STD - Affil	**(707,879)**	**11,776,988**	**(16,752,888)**	**4,268,022**
4310007	Lines Of Credit	(227,217)	(78,555)	(99,738)	(48,924)
	Interest STD - NonAffil	**(227,217)**	**(78,555)**	**(99,738)**	**(48,924)**

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IS8016 YTD Apr 2025 05/09/2025 11:15	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025
	Interest on Short Term Debt	**(935,095)**	**11,698,433**	**(16,852,626)**	**4,219,098**
4280002	Amrtz Debt Dscnt&Exp-Instl Pur	(57,527)	(57,527)	0	0
4280003	Amrtz Debt Dscnt&Exp-N/P	(7,581)	(7,581)	0	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	(191,215)	(190,715)	(500)	0
	Amort of Debt Disc. Prem & Exp	**(256,323)**	**(255,823)**	**(500)**	**-**
4281004	Amrtz Loss Rcquired Debt-Dbnt	(11,217)	(11,217)	0	0
	Amort Loss on Reacquired Debt	**(11,217)**	**(11,217)**	**-**	**-**
	Amort Gain on Reacquired Debt	**-**	**-**	**-**	**-**
	Other Interest - Fuel Recovery	**-**	**-**	**-**	**-**
4310001	Other Interest Expense	4,426,133	4,740	4,415,824	5,570
4310002	Interest on Customer Deposits	(522,534)	(522,534)	0	0
9310005	Int on Regulated Fin Leases	(5,154)	0	0	0
	Other Interest - NonAffil	**3,898,445**	**(517,794)**	**4,415,824**	**5,570**
	Other Interest Expense - Affil	**-**	**-**	**-**	**-**
	Interest Rate Hedge Unrealized (Gain)/Loss	**-**	**-**	**-**	**-**
4320000	Allw Brrwed Fnds Used Cnstr-Cr	1,087,142	346,319	47,499	693,324
	AFUDC-Borrowed Funds	**1,087,142**	**346,319**	**47,499**	**693,324**
	Total Interest Charges	**(21,063,883)**	**(13,586,918)**	**(12,389,804)**	**4,917,992**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**11,885,524**	**(1,956,256)**	**(42,055,972)**	**55,897,752**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	1,643,093	(3,521,475)	(8,182,726)	13,347,294
4092001	Inc Tax, Oth Inc&Ded-Federal	(174,270)	(101,280)	(65,337)	(7,653)
	Federal Current Income Tax	**1,468,823**	**(3,622,755)**	**(8,248,063)**	**13,339,642**
4101001	Prov Def I/T Util Op Inc-Fed	16,600,451	5,391,193	9,082,720	2,126,537
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(15,108,105)	(2,141,821)	(9,659,183)	(3,307,101)
	Federal Deferred Income Tax	**1,492,345**	**3,249,372**	**(576,463)**	**(1,180,564)**
	Federal Investment Tax Credits	**-**	**-**	**-**	**-**
	Federal Income Taxes	**2,961,169**	**(373,383)**	**(8,824,526)**	**12,159,078**
4091002	Income Taxes, UOI - State	(671,039)	(1,006,225)	(2,115,581)	2,450,767
4092002	Inc Tax, Oth Inc & Ded - State	(43,766)	(25,435)	(16,409)	(1,922)
	State Current Income Tax	**(714,805)**	**(1,031,661)**	**(2,131,990)**	**2,448,845**
	State Deferred Income Tax	**-**	**-**	**-**	**-**
	State Investment Tax Credits	**-**	**-**	**-**	**-**
	State Income Taxes	**(714,805)**	**(1,031,661)**	**(2,131,990)**	**2,448,845**
	Local Current Income Tax	**-**	**-**	**-**	**-**
	Local Deferred Income Tax	**-**	**-**	**-**	**-**
	Local Investment Tax Credits	**-**	**-**	**-**	**-**
	Local Income Taxes	**-**	**-**	**-**	**-**
	Foreign Current Income Tax	**-**	**-**	**-**	**-**
	Foreign Deferred Income Tax	**-**	**-**	**-**	**-**
	Foreign Investment Tax Credits	**-**	**-**	**-**	**-**
	Foreign Income Taxes	**-**	**-**	**-**	**-**
	Total Income Taxes	**2,246,364**	**(1,405,044)**	**(10,956,516)**	**14,607,923**
	Equity Earnings of Subs	**-**	**-**	**-**	**-**
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	**9,639,160**	**(551,212)**	**(31,099,456)**	**41,289,828**
	Discontinued Operations (Net of Taxes)	**-**	**-**	**-**	**-**
	Cumulative Effect of Accounting Changes	**-**	**-**	**-**	**-**
	Extraordinary Income / (Expenses)	**-**	**-**	**-**	**-**

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IS8016 YTD Apr 2025 05/09/2025 11:15	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025
	NET INCOME	**9,639,160**	**(551,212)**	**(31,099,456)**	**41,289,828**
	Minority Interest	**-**	**-**	**-**	**-**
	Preferred Stock Dividend Subs	**-**	**-**	**-**	**-**
	Earnings to Common Shareholders	**9,639,160**	**(551,212)**	**(31,099,456)**	**41,289,828**
	NET INCOME (LOSS) NODE before PS	**9,639,160**	**(551,212)**	**(31,099,456)**	**41,289,828**
	Double Check on Net Income Node after PS	0	0	-	-

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BS8216 YTD Apr 2025 05/09/2025 20:26	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025
	ASSETS				
	Cash and Cash Equivalents	**657,816**	**657,816**	**0**	**0**
	Other Cash Deposits	**22,976**	**12,667**	**10,042**	**267**
	Customers	19,471,077	15,027,160	1,990,730	2,453,188
	Accrued Unbilled Revenues	2,190,113	2,190,113	0	0
	Miscellaneous Accounts Receivable	18,448,922	3,890,258	47,750,110	17,279,946
	Allowances for Uncollectible Accounts	(535)	(535)	0	0
	Accounts Receivable	**40,109,578**	**21,106,996**	**49,740,839**	**19,733,134**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**75,803,907**	**6,230,801**	**66,794,724**	**2,778,382**
	Risk Management Contracts - Current	**2,902,521**	**0**	**2,902,521**	**0**
	Margin Deposits	**4,352,738**	**8,493**	**4,344,246**	**0**
	Unrecovered Fuel - Current	**8,156,515**	**0**	**8,156,515**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**2,627,543**	**2,271,027**	**259,911**	**96,605**
	TOTAL CURRENT ASSETS	**134,633,595**	**30,287,799**	**132,208,798**	**22,608,389**
	Electric Production	**1,292,155,672**	**1,351,527,005**	**1,326,017,358**	**964,649,282**
	Electric Transmission	**960,216,348**	**0**	**0**	**0**
	Electric Distribution	**1,218,203,145**	**0**	**0**	**0**
	General Property, Plant and Equipment	**172,776,012**	**83,276**	**(45,138)**	**1,119,396**
	Construction Work-in-Progress	**154,374,406**	**51,211,513**	**6,600,988**	**96,561,906**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,797,725,585**	**1,402,821,794**	**1,332,573,207**	**1,062,330,584**
	less: Accumulated Depreciation and Amortization	**(1,275,496,106)**	**(338,733,199)**	**(664,724,947)**	**(272,037,960)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,522,229,478**	**1,064,088,594**	**667,848,260**	**790,292,623**
	Net Regulatory Assets	**619,084,166**	**151,545,974**	**457,197,063**	**10,341,130**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**229,990**	**0**	**229,990**	**0**
	Employee Benefits and Pension Assets	**39,195,594**	**17,597,549**	**20,779,588**	**818,457**
	Other Non Current Assets	**40,206,139**	**12,714,248**	**23,500,659**	**3,991,232**
	TOTAL OTHER NON-CURRENT ASSETS	**698,715,888**	**181,857,770**	**501,707,299**	**15,150,819**
	TOTAL ASSETS	**3,355,578,961**	**1,276,234,164**	**1,301,764,358**	**828,051,831**
	LIABILITIES				
	Accounts Payable	**104,474,728**	**86,647,118**	**52,767,589**	**15,531,413**
	Advances from Affiliates	**63,965,567**	**(741,024,834)**	**1,083,792,601**	**(278,802,200)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**300,000,000**	**300,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	391,382	12,772	378,610	0
2440021	S/T Liability MTM Collateral	(298,210)	(12,772)	(285,438)	0
	Risk Management Liabilities - MTM	93,172	0	93,172	0
	Risk Management Liabilities	**93,172**	**0**	**93,172**	**0**
	Accrued Taxes	**24,421,430**	**(10,106,476)**	**(39,606,444)**	**74,134,350**

BS8216 YTD Apr 2025 05/09/2025 20:26	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025
	Memo: Property Taxes	23,515,663	13,540,582	5,511,516	4,463,565
	Accrued Interest	**23,415,768**	**23,415,768**	**0**	**0**
	Risk Management Collateral	496,705	0	496,705	0
	Utility Customer Deposits	38,012,175	38,012,175	0	0
	Deposits - Customer and Collateral	**38,508,879**	**38,012,175**	**496,705**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	135,618	58,760	76,858	0
	Obligations under Operating Leases - Current	412,270	271,976	62,201	78,093
	Tax Collections Payable	1,828,314	1,828,314	0	0
	Revenue Refunds - Accrued	292,954	0	126,695	166,259
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	1,261,187	1,114,486	128,319	18,382
	Accrued Rents	(4,433)	(4,433)	0	0
	Accrued ICP	433,923	402,881	27,847	3,195
	Accrued Vacations	2,556,613	2,277,584	250,949	28,080
	Misc Employee Benefits	1,586,285	1,423,111	164,087	(912)
	Payroll Deductions	105,039	92,922	10,219	1,897
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	193,346	174,391	18,954	0
2530022	Customer Advance Receipts	2,217,537	2,217,537	0	0
	Customer Advance	2,217,537	2,217,537	0	0
2420511	Control Cash Disburse Account	591,719	591,719	0	0
	Control Cash Disbursement Account	591,719	591,719	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	163,541	0	163,541	0
2300002	ARO - Current	3,620,144	0	3,620,144	0
2420088	Econ. Development Fund Curr	705,831	705,831	0	0
2420512	Unclaimed Funds	16,001	16,001	0	0
2420542	Acc Cash Franchise Req	101,538	101,538	0	0
242059225	Sales Use Tax - Leased Equip	30	0	0	30
2420643	Accrued Audit Fees	41,812	31,356	6,434	4,021
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	544,027	541,848	0	2,179
2530112	Other Deferred Credits-Curr	19,059	18,534	525	0
2530124	Contr In Aid of Constr Advance	796,596	796,596	0	0
	Misc Current and Accrued Liabilities	6,009,263	2,212,388	3,790,644	6,231
	Current Other and Accrued Liabilities	17,071,747	12,330,900	4,517,716	223,131
	Other Current Liabilities	**17,619,635**	**12,661,636**	**4,656,775**	**301,224**
	TOTAL CURRENT LIABILITIES	**572,499,180**	**(290,394,613)**	**1,102,200,397**	**(188,835,212)**
	Long-Term Debt - Affiliated	**0**	**0**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,061,237,421**	**1,061,237,421**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(570,563)**	**(570,563)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,060,666,859*	*1,060,666,859*	*0*	*0*
	Long-Term Risk Management Liabilities	**141,645**	**0**	**141,645**	**0**
	Deferred Income Taxes	**487,556,235**	**172,634,020**	**221,021,088**	**93,901,128**
	Deferred Investment Tax Credits	**0**	**0**	**0**	**0**

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BS8216 YTD Apr 2025 05/09/2025 20:26	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025	YTD Apr 2025
	Regulatory Liabilities and Deferred Credits	**124,662,399**	**94,193,863**	(4,431,583)	**34,900,119**
	Memo - Reg Liab and Def ITC	*124,662,399*	*94,193,863*	*(4,431,583)*	*34,900,119*
	Asset Retirement Obligation	**86,701,791**	**224,223**	**86,477,568**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**8,553,767**	**14,236,721**	(7,486,451)	**1,803,497**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redemption	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	812,224	681,591	130,633	0
	Obligations Under Operating Leases	2,934,201	2,502,307	158,406	273,488
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	101,503	101,503	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530044	Neigh Help Neig-Cust Donations	(15)	(15)	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	20,384	20,384	0	0
2530101	MACSS Unidentified EDI Cash	7,488	7,488	0	0
2530185	O\U Accounting of ExpensesT	4,471	0	4,471	0
2530188	Long Term Assoc AP	8,724,937	0	0	8,724,937
2530190	QUAL OF SVC PENALTIES - LT	72,870	0	0	72,870
	Def Credits - Other	8,830,135	27,857	4,471	8,797,807
	Total Other Deferred Credits	8,931,639	129,360	4,471	8,797,807
	Accumulated Provisions - Rate Refund	1,595,781	0	0	1,595,781
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**14,273,844**	**3,313,257**	**293,510**	**10,667,077**
	TOTAL NON-CURRENT LIABILITIES	**1,782,556,540**	**1,345,268,943**	**296,015,777**	**141,271,820**
	TOTAL LIABILITIES	**2,355,055,720**	**1,054,874,330**	**1,398,216,174**	(47,563,393)
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,038,123**	**106,025,371**	**335,469,573**	**84,543,179**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**424,035,118**	**92,930,413**	(442,208,992)	**773,313,697**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**1,000,523,241**	**221,359,834**	(96,451,816)	**875,615,223**
	Memo: Total Equity	1,000,523,241	221,359,834	(96,451,816)	875,615,223
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,355,578,961**	**1,276,234,164**	**1,301,764,358**	**828,051,831**

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BS8216 YTD Apr 2024 05/09/2024 15:06	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Apr 2024	YTD Apr 2024	YTD Apr 2024	YTD Apr 2024
	ASSETS				
	Cash and Cash Equivalents	**407,871**	**407,871**	**0**	**0**
	Other Cash Deposits	**39,370**	**17,496**	**21,256**	**618**
	Customers	16,078,862	13,639,968	555,651	1,883,243
	Accrued Unbilled Revenues	(980,387)	(980,387)	0	0
	Miscellaneous Accounts Receivable	20,465,899	3,717,974	49,912,286	22,268,998
	Allowances for Uncollectible Accounts	(51)	(28)	(2)	(21)
	Accounts Receivable	**35,564,323**	**16,377,528**	**50,467,935**	**24,152,220**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**97,951,192**	**7,100,822**	**87,662,241**	**3,188,129**
	Risk Management Contracts - Current	**1,242,905**	**13,132**	**1,229,773**	**0**
	Margin Deposits	**7,420,292**	**30,937**	**7,389,355**	**0**
	Unrecovered Fuel - Current	**7,234,844**	**0**	**7,234,844**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**6,426,083**	**6,173,757**	**173,839**	**78,486**
	TOTAL CURRENT ASSETS	**156,286,880**	**30,121,543**	**154,179,243**	**27,419,453**
	Electric Production	**1,240,603,500**	**1,270,914,511**	**1,277,228,413**	**856,233,535**
	Electric Transmission	**851,804,154**	**0**	**0**	**0**
	Electric Distribution	**1,137,933,503**	**0**	**0**	**0**
	General Property, Plant and Equipment	**175,192,837**	**83,276**	**(45,138)**	**1,119,396**
	Construction Work-in-Progress	**172,000,696**	**59,195,639**	**22,721,047**	**90,084,009**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,577,534,690**	**1,330,193,427**	**1,299,904,322**	**947,436,941**
	less: Accumulated Depreciation and Amortization	**(1,223,386,567)**	**(324,400,294)**	**(637,852,128)**	**(261,134,145)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,354,148,123**	**1,005,793,133**	**662,052,195**	**686,302,795**
	Net Regulatory Assets	**554,404,714**	**129,778,903**	**416,232,308**	**8,393,503**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**530,542**	**0**	**530,542**	**0**
	Employee Benefits and Pension Assets	**25,567,445**	**13,496,940**	**11,316,045**	**754,460**
	Other Non Current Assets	**44,521,837**	**12,583,403**	**25,978,668**	**5,959,767**
	TOTAL OTHER NON-CURRENT ASSETS	**625,024,539**	**155,859,246**	**454,057,563**	**15,107,730**
	TOTAL ASSETS	**3,135,459,542**	**1,191,773,922**	**1,270,289,001**	**728,829,979**
	LIABILITIES				
	Accounts Payable	**92,722,109**	**76,620,110**	**60,443,650**	**11,091,708**
	Advances from Affiliates	**45,183,995**	**(755,617,632)**	**1,025,596,145**	**(224,794,518)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**215,000,000**	**215,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	5,383,167	0	5,383,167	0
2440021	S/T Liability MTM Collateral	(157,562)	0	(157,562)	0
	Risk Management Liabilities - MTM	5,225,605	0	5,225,605	0
	Risk Management Liabilities	**5,225,605**	**0**	**5,225,605**	**0**
	Accrued Taxes	**39,393,158**	**8,521,707**	**(27,406,933)**	**58,278,385**
	Memo: Property Taxes	43,970,433	22,582,036	6,573,562	14,814,835
	Accrued Interest	**22,462,994**	**22,462,994**	**0**	**0**
	Risk Management Collateral	447,943	0	447,943	0
	Utility Customer Deposits	37,597,523	37,597,523	0	0

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BS8216 YTD Apr 2024 05/09/2024 15:06	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Apr 2024	YTD Apr 2024	YTD Apr 2024	YTD Apr 2024
	Deposits - Customer and Collateral	**38,045,465**	**37,597,523**	**447,943**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	124,547	46,761	77,786	0
	Obligations under Operating Leases - Current	187,192	127,843	59,349	0
	Tax Collections Payable	1,865,637	1,865,637	0	0
	Revenue Refunds - Accrued	495,612	0	122,069	373,543
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	1,120,057	984,983	124,966	10,107
	Accrued Rents	2,265	2,265	0	0
	Accrued ICP	824,849	759,302	62,551	2,996
	Accrued Vacations	2,718,039	2,434,535	262,906	20,598
	Misc Employee Benefits	1,175,469	981,328	192,173	1,968
	Payroll Deductions	101,919	90,486	10,169	1,264
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	221,264	199,436	21,828	0
2530022	Customer Advance Receipts	2,932,116	2,932,116	0	0
	Customer Advance	2,932,116	2,932,116	0	0
2420511	Control Cash Disburse Account	1,553,017	1,553,017	0	0
	Control Cash Disbursement Account	1,553,017	1,553,017	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	118,665	0	118,665	0
2300002	ARO - Current	205,678	0	205,678	0
2420000	Misc Current & Accrued Liab	1,000,000	1,000,000	0	0
2420088	Econ. Development Fund Curr	653,389	653,389	0	0
2420512	Unclaimed Funds	19,358	19,358	0	0
2420542	Acc Cash Franchise Req	95,041	95,041	0	0
2420643	Accrued Audit Fees	114,591	48,216	43,259	23,117
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	560,294	559,145	0	1,149
2530112	Other Deferred Credits-Curr	159,202	159,202	0	0
2530124	Contr In Aid of Constr Advance	183,601	183,601	0	0
	Misc Current and Accrued Liabilities	3,110,503	2,718,637	367,601	24,265
	Current Other and Accrued Liabilities	16,120,746	14,521,742	1,164,263	434,742
	Other Current Liabilities	**16,432,485**	**14,696,346**	**1,301,398**	**434,742**
	TOTAL CURRENT LIABILITIES	**474,465,812**	**(380,718,953)**	**1,065,607,807**	**(154,989,683)**
	Long-Term Debt - Affiliated	**25,000,000**	**25,000,000**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,060,640,329**	**1,060,640,329**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(637,688)**	**(637,688)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,060,002,642*	*1,060,002,642*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	317,081	1,729	315,352	0
2440022	L/T Liability MTM Collateral	(1,729)	(1,729)	0	0
	Long-Term Risk Management Liabilities - MTM	315,352	0	315,352	0
	Long-Term Risk Management Liabilities	**315,352**	**0**	**315,352**	**0**
	Deferred Income Taxes	**471,858,031**	**164,991,073**	**218,875,220**	**87,991,738**
	Deferred Investment Tax Credits	**(0)**	**0**	**(0)**	**0**
	Regulatory Liabilities and Deferred Credits	**105,178,325**	**77,647,664**	**(3,031,112)**	**30,561,773**
	Memo - Reg Liab and Def ITC	*105,178,325*	*77,647,664*	*(3,031,112)*	*30,561,773*
	Asset Retirement Obligation	**17,982,040**	**206,055**	**17,775,985**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**8,400,071**	**11,300,559**	**(4,635,960)**	**1,735,471**
	Trust Preferred Securities	**0**	**0**	**0**	**0**

BS8216 YTD Apr 2024 05/09/2024 15:06	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD Apr 2024	YTD Apr 2024	YTD Apr 2024	YTD Apr 2024
	Cumulative Preferred Stocks of Subs - Mandatory Redemp	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	755,496	570,172	185,324	0
	Obligations Under Operating Leases	1,217,177	1,011,943	205,234	0
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	94,091	94,091	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	35,570	35,570	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	666	0	0	666
2530175	Legal Contingencies	(140)	(140)	0	0
2530185	O\U Accounting of ExpensesT	7,793	0	7,793	0
2530188	Long Term Assoc AP	4,125,973	0	0	4,125,973
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	4,254,478	35,430	7,793	4,211,255
	Total Other Deferred Credits	4,348,568	129,521	7,793	4,211,255
	Accumulated Provisions - Rate Refund	884,777	0	0	884,777
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**7,206,019**	**1,711,636**	**398,351**	**5,096,032**
	TOTAL NON-CURRENT LIABILITIES	**1,695,942,479**	**1,340,859,629**	**229,697,836**	**125,385,014**
	TOTAL LIABILITIES	**2,170,408,291**	**960,140,677**	**1,295,305,643**	**(29,604,669)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**527,571,001**	**106,025,371**	**336,670,571**	**84,875,059**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**387,030,250**	**103,203,825**	**(371,974,816)**	**655,801,241**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**965,051,251**	**231,633,245**	**(25,016,642)**	**758,434,648**
	Memo: Total Equity	965,051,251	231,633,245	(25,016,642)	758,434,648
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,135,459,542**	**1,191,773,922**	**1,270,289,001**	**728,829,979**

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KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - April, 2025

Final

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		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,324,153,881.22	3,645,168.65	(2,381,870.25)	0.00	0.00	1,325,417,179.62
101/106	CLOUD GENERATION	446,948.71	66,402.90	(6,125.51)	0.00	0.00	507,226.10
	TOTAL PRODUCTION	**1,324,600,829.93**	**3,711,571.55**	**(2,387,995.76)**	**0.00**	**0.00**	**1,325,924,405.72**
101/106	TRANSMISSION	955,494,282.91	10,803,246.67	(1,648,247.60)	0.00	0.00	964,649,281.98
101/106	CLOUD TRANSMISSION	302,831.60	105,188.11	(1,258.48)	0.00	0.00	406,761.23
101/106	DISTRIBUTION	1,328,226,510.37	25,835,537.90	(4,146,329.56)	0.00	0.00	1,349,915,718.71
101/106	CLOUD DISTRIBUTION	2,053,474.66	357,505.37	(134,977.49)	0.00	0.00	2,276,002.54
	TOTAL (ACCOUNTS 101 & 106)	**3,610,677,929.47**	**40,813,049.60**	**(8,318,808.89)**	**0.00**	**0.00**	**3,643,172,170.18**
1011001/12	CAPITAL LEASES	1,329,493.17	0.00	0.00	80,299.63	0.00	1,409,792.80
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**3,612,007,422.64**	**40,813,049.60**	**(8,318,808.89)**	**80,299.63**	**0.00**	**3,644,581,962.98**
1050001	PLANT HELD FOR FUTURE USE	801,671.21	0.00	0.00	0.00	0.00	801,671.21
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEGINNING BALANCE	115,771,812.73					
107000X	ADDITIONS		78,886,546.62				
107000X	TRANSFERS		(40,283,953.22)				
107000X	ENDING BALANCE		38,602,593.40				154,374,406.13
107000X	**CLOUD CONSTRUCTION WIP:**						
107000X	BEGINNING BALANCE	1,813,515.61					
107000X	ADDITIONS		606,279.27				
107000X	TRANSFERS		(529,096.38)				
107000X	ENDING BALANCE		77,182.89				1,890,698.50
	TOTAL ELECTRIC UTILITY PLANT	**3,730,394,422.19**	**79,492,825.89**	**(8,318,808.89)**	**80,299.63**	**0.00**	**3,801,648,738.82**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	502,365.72	0.00	0.00	0.00	0.00	502,365.72
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1210003	NONUTILITY PROPERTY-WIP						
	BEGINNING BALANCE	0.00					
	ADDITIONS		0.00				
	TRANSFERS		0.00				
	ENDING BALANCE		0.00				0.00
1210016	NONUTILITY PROPERTY-CCNC	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	655,168.37	0.00	0.00	0.00	0.00	655,168.37
	TOTAL NONUTILITY PLANT	**1,157,534.09**	**0.00**	**0.00**	**0.00**	**0.00**	**1,157,534.09**

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KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - April, 2025

Final

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		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
.	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	640,384,146.97	13,665,223.79	(2,387,995.76)	(793,172.91)	12,151,968.00	663,020,170.09
1080001/11	TRANSMISSION	302,596,611.20	9,398,983.91	(1,649,506.08)	(2,237,205.24)	4,549,736.60	312,658,620.39
1080001/11	DISTRIBUTION	407,529,530.89	16,937,055.21	(4,281,307.05)	(935,738.85)	15,289,461.01	434,539,001.21
1080013	PRODUCTION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	0.00	0.00	0.00	0.00	0.00	0.00
1080026	CLOUD COMPUTE IMPLEMENT COST	0.00	16,788.21	0.00	0.00	194,148.78	210,936.99
1080026	CLOUD COMPUTE IMPLEMENT COST	0.00	13,240.76	0.00	0.00	95,522.75	108,763.51
1080026	CLOUD COMPUTE IMPLEMENT COS	0.00	68,241.13	0.00	0.00	658,855.33	727,096.46
	RETIREMENT WORK IN PROGRESS	(14,227,110.14)	0.00	0.00	(5,386,456.64)	3,966,117.00	(15,647,449.78)
	TOTAL (108X accounts)	**1,336,283,178.93**	**40,099,533.01**	**(8,318,808.89)**	**(9,352,573.64)**	**36,905,809.47**	**1,395,617,138.88**
	NUCLEAR					0.00	
1110001	PRODUCTION	11,897,023.95	256,485.02	0.00	0.00	(12,153,508.95)	0.02
1110007	CLOUD IMPLEMENT COST PRODUCT	185,158.67	7,449.15	0.00	0.00	(192,607.83)	(0.01)
1110001	TRANSMISSION	4,426,015.33	127,811.32	0.00	0.00	(4,553,826.66)	(0.01)
1110007	CLOUD IMPLEMENT COST TRANSMIS	86,385.47	5,047.19	0.00	0.00	(91,432.69)	(0.03)
1110001	DISTRIBUTION	14,844,619.51	399,905.33	0.00	0.00	(15,185,450.73)	59,074.11
1110007	CLOUD IMPLEMENT COST DISTRIBU	732,931.68	29,933.90	0.00	0.00	(762,865.61)	(0.03)
	TOTAL (111X accounts)	**32,172,134.61**	**826,631.91**	**0.00**	**0.00**	**(32,939,692.47)**	**59,074.05**
1011006	CAPITAL LEASES	414,736.20	0.00	0.00	0.00	43,446.01	458,182.21
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**1,368,870,049.74**	**40,926,164.92**	**(8,318,808.89)**	**(9,352,573.64)**	**4,009,563.01**	**1,396,134,395.14**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	179,574.02	2,223.26	0.00	0.00	0.00	181,797.28
1220002	Depr&Amrt of Nonutl Prop-Leasd	0.00	0.00	0.00	0.00	0.00	0.00
1220003	Depr&Amrt of Nonutl Prop-WIP	0.00	0.00	0.00	0.00	0.00	0.00
1220004	Depletion - Owned	0.00	0.00	0.00	0.00	0.00	0.00
1240027	Other Property - RWIP	35,121.36	0.00	0.00	0.00	0.00	35,121.36
1240028	Other Property - Retirement	(46,947.27)	0.00	0.00	0.00	0.00	(46,947.27)
	TOTAL NONUTILITY PLANT	**167,748.11**	**2,223.26**	**0.00**	**0.00**	**0.00**	**169,971.37**

U.S. Department of Energy	**Monthly Electric Utility Sales and Revenue**	Form Approval
Energy Information Administration	**Report with State Distributions – 2025**	OMB NO.1905-0129
Form EIA-826		(Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**

Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650.

Utility Name: Kentucky Power Company **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan___ Feb___ Mar___ Apr_X__ May___ Jun___ Jul___ Aug___ Sep___ Oct___ Nov___ Dec__ , 2025

Contact Person: Sandra Vargo	**Phone number: 614-716-2671**
Email: slvargo@aep.com	**Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	$ 18,387	$ 13,919	$ 13,166	$ -	$ 45,472
	b. Megwatthours	$ 105,826	$ 102,563	$ 165,755	$ -	$ 374,144
	c. Number of consumers	$ 130,510	$ 30,689	$ 932	$ -	$ 162,131
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					

Note:

KPSC Case No. 2025-00257
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June 27th, 2025

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed May 2025 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:	
1-12	Income Statement
1-3	Details of Operating Revenues
5-10	Operating Expenses – Functional Expenses
12	Detail Statement of Taxes
Balance Sheet:	
13	Balance Sheet – Assets & Other Debits
13-15	Balance Sheet – Liabilities & Other Credits
14-15	Deferred Credits
15	Statement of Retained Earnings
Utility Property:	
16-17	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Digitally signed by Brian J. Frantz
DN: cn=Brian J. Frantz, o=AEP, ou=Corporate Accounting, email=bjfrantz@aep.com
Reason: I have reviewed this document
Date: 2025.06.27 14:21:38 -04'00'

Brian J Frantz
Director - Corporate Accounting

American Electric Power

INCOME STATEMENT

IS8016
YTD May 2025
06/07/2025 09:18

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol IS8016 Actual YTD May 2025	Kentucky Power Company - Distribution 110 Actual YTD May 2025	Kentucky Power Company - Generation 117 Actual YTD May 2025	Kentucky Power Company - Transmission 180 Actual YTD May 2025
		REVENUES				
4400001		Residential Sales-W/Space Htg	71,704,894	73,174,106	(1,469,211)	0
4400002		Residential Sales-W/O Space Ht	28,302,019	29,361,517	(1,059,498)	0
4400005		Residential Fuel Rev	30,986,505	30,986,505	0	0
	A	**Revenue - Residential Sales**	**130,993,418**	**133,522,128**	**(2,528,710)**	**-**
4420001		Commercial Sales	41,115,238	42,504,874	(1,389,636)	0
4420006		Sales to Pub Auth - Schools	6,958,924	6,958,924	0	0
4420007		Sales to Pub Auth - Ex Schools	8,151,241	8,402,372	(251,132)	0
4420013		Commercial Fuel Rev	20,906,287	20,906,287	0	0
	A	**Revenue - Commercial Sales**	**77,131,690**	**78,772,457**	**(1,640,768)**	**-**
	B	**Revenue - Industrial Sales - Affiliated**	**-**	**-**	**-**	**-**
4420002		Industrial Sales (Excl Mines)	32,610,380	34,282,936	(1,672,556)	0
4420004		Ind Sales-NonAffil(Incl Mines)	6,958,389	6,958,389	0	0
4420016		Industrial Fuel Rev	29,506,551	29,506,551	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**69,075,320**	**70,747,876**	**(1,672,556)**	**-**
		Revenue - Industrial Sales	**69,075,320**	**70,747,876**	**(1,672,556)**	**-**
	A	**Revenue - Gas Products Sales**	**-**	**-**	**-**	**-**
	A	**Revenue - Gas Transportation & Storage Sales**	**-**	**-**	**-**	**-**
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	**-**	**-**	**-**	**-**
4440000		Public Street/Highway Lighting	778,852	783,110	(4,258)	0
4440002		Public St & Hwy Light Fuel Rev	129,715	129,715	0	0
	A	**Revenue - Other Retail Sales**	**908,567**	**912,825**	**(4,258)**	**-**
	B	**Revenue - Other Retail Sales - Affiliated**	**-**	**-**	**-**	**-**
		Revenue - Retail Sales	**278,108,996**	**283,955,287**	**(5,846,291)**	**-**
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	36,060,334
4561033		PJM NITS Revenue - Affiliated	36,711,477	0	0	36,711,477
4561034		PJM TO Adm. Serv Rev - Aff	79,943	0	0	79,943
4561035		PJM Affiliated Trans NITS Cost	(23,895,349)	0	(23,895,349)	0
4561036		PJM Affiliated Trans TO Cost	(41,536)	0	(41,536)	0
4561059		Affil PJM Trans Enhancmnt Rev	686,758	0	0	686,758
4561060		Affil PJM Trans Enhancmnt Cost	(447,008)	0	(447,008)	0
4561062		PROVISION RTO Tran Cost Affi	665,580	0	665,580	0
4561063		PROVISION RTO Tran Rev Aff	(136,945)	0	0	(136,945)
	B	**Revenue - Transmission-Affiliated**	**13,622,918**	**-**	**(23,718,313)**	**73,401,565**
4470150		Transm. Rev.-Dedic. Whlsl/Muni	(10,140)	0	(1,075,062)	1,064,922
4470206		PJM Trans loss credits-OSS	48,299	0	48,299	0
4470209		PJM transm loss charges-OSS	(74,933)	0	(74,933)	0
4561005		PJM Point to Point Trans Svc	1,057,593	0	1,057,593	0
4561006		PJM Trans Owner Admin Rev	39,182	0	0	39,182
4561007		PJM Network Integ Trans Svc	4,935,791	0	0	4,935,791
4561019		Oth Elec Rev Trans Non Affil	23,850	0	0	23,850
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	844	0	0	844
4561029		PJM NITS Revenue Whsl Cus-NAff	1,247,349	0	0	1,247,349
4561030		PJM TO Serv Rev Whls Cus-NAff	2,833	0	0	2,833
4561045		PJM Non-Aff Gen IPP Rev	9,970	0	0	9,970
4561058		NonAffil PJM Trans Enhncmt Rev	788,461	0	0	788,461
4561061		NAff PJM RTEP Rev for Whsl-FR	23,334	0	0	23,334
4561064		PROVISION RTO Tran Rv Frml Rts	(4,600)	0	0	(4,600)
4561065		PROVISION RTO Tran Rev NonAff	(20,575)	0	0	(20,575)
	A	**Revenue - Transmission-NonAffiliated**	**8,067,258**	**-**	**(44,102)**	**8,111,361**
		Revenue - Transmission	**21,690,176**	**-**	**(23,762,416)**	**81,512,926**

KPSC Case No. 2025-00257
Application - Section II
Filing Requirements
Exhibit R
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American Electric Power

IS8016 YTD May 2025 06/07/2025 09:18		INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
		Layout: IS8016				
17A V2099-01-01		Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD May 2025	YTD May 2025	YTD May 2025	YTD May 2025
	B	**Revenue - Resale-Affiliated**	-	-	-	-
4470027		Whsal/Muni/Pb Ath Fuel Rev	1,515,111	0	1,515,111	0
4470033		Whsal/Muni/Pub Auth Base Rev	1,324,922	0	1,324,922	0
4470082		Financial Electric Realized	(2,026)	0	(2,026)	0
4470089		PJM Energy Sales Margin	343,834	0	343,834	0
4470098		PJM Oper.Reserve Rev-OSS	(34,578)	0	(34,578)	0
4470099		Capacity Cr. Net Sales	(50,881)	0	(50,881)	0
4470100		PJM FTR Revenue-OSS	77,726	0	77,726	0
4470103		PJM Energy Sales Cost	4,942,739	0	4,942,739	0
4470115		PJM Meter Corrections-OSS	(9,957)	0	(9,957)	0
4470116		PJM Meter Corrections-LSE	(166,064)	0	(166,064)	0
4470126		PJM Incremental Imp Cong-OSS	(46,316)	0	(46,316)	0
4470175		OSS Sharing Reclass - Retail	2,672,804	0	2,672,804	0
4470176		OSS Sharing Reclass-Reduction	(2,672,804)	0	(2,672,804)	0
4470220		PJM Regulation - OSS	2,397,691	0	2,397,691	0
4470221		PJM Spinning Reserve - OSS	49,348	0	49,348	0
5550080		PJM Hourly Net Purch.-FERC	(2,878,944)	0	(2,878,944)	0
	A	**Revenue - Resale-NonAffiliated**	**7,462,606**	**-**	**7,462,606**	**-**
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**7,462,606**	**-**	**7,462,606**	**-**
4470074		Sale for Resale-Aff-Trnf Price	0	0	186,524,496	0
4540001		Rent From Elect Property - Af	781,938	486,255	0	465,700
	B	**Revenue - Other Ele-Affilliated**	**781,938**	**486,255**	**186,524,496**	**465,700**
4500000		Forfeited Discounts	556,340	556,340	0	0
4510001		Misc Service Rev - Nonaffil	38,869	38,795	0	74
4540002		Rent From Elect Property-NAC	1,004,342	875	984,192	19,275
4540005		Rent from Elec Prop-Pole Attch	1,973,913	1,970,321	0	3,592
4560007		Oth Elect Rev - DSM Program	430,276	430,276	0	0
5010040		Gas Procuremnt Sales Net	(237,984)	0	(237,984)	0
		Revenue - Other Ele-NonAffilliated	**3,765,756**	**2,996,606**	**746,208**	**22,941**
		Revenue - Gas	-	-	-	-
4118002		Comp. Allow Gains Title IV SO2	7	7	0	0
		Gain/(Loss) on Allowances	**7**	**7**	**-**	**-**
	A	**Revenue - Other Ele-NonAffilliated**	**3,765,763**	**2,996,613**	**746,208**	**22,941**
		Revenue - Other Opr Electric	**4,547,700**	**3,482,868**	**187,270,705**	**488,642**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
4170004		Rev from Non-Util Oper NonAfil	136,001	136,001	0	0
	D	**Revenues Non-Utility Operations - NonAffiliated**	**136,001**	**136,001**	**-**	**-**
		Revenues from Non-Utility Operations	**136,001**	**136,001**	**-**	**-**
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operatng Rental Income	400	400	0	0
4180005		Non-Opratng Rntal Inc-Depr	(2,779)	0	0	(2,779)
	D	**Non-Operating Rental Income - NonAffiliated**	**(2,379)**	**400**	**-**	**(2,779)**
		Non-Operating Rental Income	**(2,379)**	**400**	**-**	**(2,779)**
	C	**Non-Operating Misc Income -Affiliated**	-	-	-	-
4210002		Misc Non-Op Inc-NonAsc-Rents	447	0	447	0
4210007		Misc Non-Op Inc - NonAsc - Oth	431	388	44	0
	D	**Non-Operating Misc Income - NonAffiliated**	**879**	**388**	**491**	**-**

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American Electric Power

INCOME STATEMENT

IS8016
YTD May 2025
06/07/2025 09:18

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD May 2025	Kentucky Power Company - Distribution 110 Actual YTD May 2025	Kentucky Power Company - Generation 117 Actual YTD May 2025	Kentucky Power Company - Transmission 180 Actual YTD May 2025
	Non-Operating Misc Income	**879**	**388**	**491**	**-**
4560015	Other Electric Revenues - ABD	188,864	188,864	0	0
D	**Associated Business Development Income**	**188,864**	**188,864**	**-**	**-**
	Revenue - Other Opr - Other	**323,364**	**325,652**	**491**	**(2,779)**
=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	**-**	**-**	**-**	**-**
=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***323,364***	***325,652***	***491***	***(2,779)***
	Revenue - Other Operating	**4,871,064**	**3,808,520**	**187,271,196**	**485,863**
4491005	Tran Prov Trans Ref NonAffil	(100,696)	0	0	(100,696)
4491006	Tran Prov Trans Ref Frml Rate	(22,767)	0	0	(22,767)
A	**Provision for Rate Refund - NonAffiliated**	**(123,463)**	**-**	**-**	**(123,463)**
4491007	Trans Prov Trans Refunds Affil	(673,486)	0	0	(673,486)
B	**Provision for Rate Refund - Affiliated**	**(673,486)**	**-**	**-**	**(673,486)**
	Provision for Rate Refund	**(796,949)**	**-**	**-**	**(796,949)**
A	**Revenue - Power Sales**	**-**	**-**	**-**	**-**
	TOTAL OPERATING REVENUES	**311,335,893**	**287,763,807**	**165,125,095**	**81,201,840**
=(A)	*Memo: G/T/D Revenue*	*297,281,160*	*286,951,900*	*2,318,421*	*8,010,839*
=(B)	*Memo: Other Affiliated Revenue*	*13,731,370*	*486,255*	*162,806,183*	*73,193,780*
=(C)	*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
=(D)	*Memo: Revenue-Oth Opr-Oth Nor*	*323,364*	*325,652*	*491*	*(2,779)*
	Memo: Total Operating Revenues	*311,335,893*	*287,763,807*	*165,125,095*	*81,201,840*
=(E)=(B)+(C)	*Memo: Affiliated Revenue*	***13,731,370***	***486,255***	***162,806,183***	***73,193,780***
=(F)=(D)+(A)	*Memo: Non-Affiliated Revenue*	***297,604,523***	***287,277,552***	***2,318,912***	***8,008,060***
	Memo: Total Operating Revenues	***311,335,893***	***287,763,807***	***165,125,095***	***81,201,840***
	FUEL EXPENSES				
5010000	Fuel	3,660,843	32	3,660,791	21
5010001	Fuel Consumed	23,523,787	0	23,523,787	0
5010003	Fuel - Procure Unload & Handle	1,248,282	0	1,248,282	0
5010012	Ash Sales Proceeds	3,755	0	3,755	0
5010019	Fuel Oil Consumed	1,363,298	0	1,363,298	0
5010020	Nat Gas Consumed Steam	17,323,342	0	17,323,342	0
5010021	Transp Gas Consumed Steam	194,033	0	194,033	0
5010027	Gypsum handling/disposal costs	526,352	0	526,352	0
5010028	Gypsum Sales Proceeds	(551,664)	0	(551,664)	0
5010034	Gas Transp Res Fees-Steam	2,609,308	0	2,609,308	0
	Fuel Expense Total	**49,901,337**	**32**	**49,901,284**	**21**
5010005	Fuel - Deferred	4,895,937	0	4,895,937	0
	Deferred Fuel Expense	**4,895,937**	**-**	**4,895,937**	**-**
	Over Under Fuel Expense				
	Fuel for Electric Generation	**54,797,274**	**32**	**54,797,221**	**21**
	Fuel from Affiliates for Electric Generation	**-**	**-**	**-**	**-**
5090000	Allow Consum Title IV SO2	6,539	0	6,539	0
5090009	Allow Consumpt CSAPR SO2	32	0	32	0
	Allowances - Consumption	**6,571**	**-**	**6,571**	**-**
5020002	Urea Expense	308,078	0	308,078	0
5020004	Lime-Related Expenses	688,301	0	688,301	0
	Emissions Control - Chemicals	**996,379**	**-**	**996,379**	**-**
	Total Fuel for Electric Generation	**55,800,224**	**32**	**55,800,172**	**21**
	Memo: NonAff Fuel/Allow/Emissions	***55,800,224***	***32***	***55,800,172***	***21***
5550029	Purch Power-Assoc-Trnsfr Price	0	186,524,496	0	0

American Electric Power

IS8016 YTD May 2025 06/07/2025 09:18	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD May 2025	YTD May 2025	YTD May 2025	YTD May 2025
	Purchased Electricity from AEP - Affiliates	**-**	**186,524,496**	**-**	**-**
5550001	Purch Pwr-NonTrading-Nonassoc	61,962,438	0	61,962,438	0
5550023	Purch Power Capacity -NA	1,849,523	0	1,849,523	0
5550039	PJM Inadvertent Mtr Res-OSS	(2,423)	0	(2,423)	0
5550040	PJM Inadvertent Mtr Res-LSE	(34,251)	0	(34,251)	0
5550074	PJM Reactive-Charge	1,378,202	0	1,378,202	0
5550075	PJM Reactive-Credit	(597,865)	0	(597,865)	0
5550076	PJM Black Start-Charge	181,772	0	181,772	0
5550078	PJM Regulation-Charge	397,265	0	397,265	0
5550079	PJM Regulation-Credit	212,058	0	212,058	0
5550083	PJM Sync & Non Sync-Charge	449,160	0	449,160	0
5550084	PJM Sync & Non Sync-Credit	(93,389)	0	(93,389)	0
5550123	PJM OpRes-LSE-Charge	3,639,493	0	3,639,493	0
5550124	PJM Implicit Congestion-LSE	2,746,925	0	2,746,925	0
5550132	PJM FTR Revenue-LSE	(6,042,615)	0	(6,042,615)	0
5550137	PJM OpRes-LSE-Credit	(36,771)	0	(36,771)	0
5550326	PJM Transm Loss Charges - LSE	2,976,016	0	2,976,016	0
5550327	PJM Transm Loss Credits-LSE	(1,609,963)	0	(1,609,963)	0
5550328	PJM FC Penalty Credit	(1,969)	0	(1,969)	0
	Purchased Electricity for Resale - NonAffiliated	**67,373,607**	**-**	**67,373,606**	**0**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**
	Purchased Gas for Resale - NonAffiliated	**-**	**-**	**-**	**-**
	Total Purchased Power	**67,373,607**	**186,524,496**	**67,373,606**	**0**
	GROSS MARGIN	**188,162,062**	**101,239,278**	**41,951,317**	**81,201,819**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	1,611,239	7,488	1,599,515	4,236
5020000	Steam Expenses	826,504	0	826,504	0
5050000	Electric Expenses	25,929	0	25,929	0
5060000	Misc Steam Power Expenses	1,981,031	(19,112)	1,982,766	17,376
5060002	Misc Steam Power Exp-Assoc	22,519	0	22,519	0
5070006	Rents - Associated	966	0	966	0
	Steam Generation Op Exp	**4,468,187**	**(11,624)**	**4,458,198**	**21,612**
	Nuclear Generation Op Exp	**-**	**-**	**-**	**-**
5390000	Misc Hydr Power Generation Exp	(0)	0	0	0
	Hydro Generation Op Exp	**(0)**	**-**	**-**	**-**
5560000	Sys Control & Load Dispatching	19,979	0	19,979	0
5570000	Other Expenses	315,326	0	315,326	0
5570007	Other Pwr Exp - Wholesale RECs	243	243	0	0
5570025	MATL-SAFETY	1	0	0	1
5581000	Oper Supervision & Engineering	146	12	123	11
5581300	Oper Supervision & Engineering	2,335	197	1,951	187
5581400	Wind Turb Gen&Oth Plnt Op-Mjr	411	86	236	89
5582000	Solar Panel Gen&Oth Plt Op-Mjr	2	0	2	0
5757000	PJM Admin-MAM&SC- OSS	25,989	0	25,989	0
5757001	PJM Admin-MAM&SC- Internal	585,132	0	585,132	0
	Other Generation Op Exp	**949,564**	**538**	**948,739**	**288**
5600000	Oper Supervision & Engineering	906,623	14,740	5,924	885,960
5612000	Load Dispatch-Mntr&Op TransSys	260,206	3,656	512	256,038
5613000	Load Dispatch-Trans Srvc&Sched	(55)	0	0	(55)
5614000	PJM Admin-SSC&DS-OSS	32,190	0	32,190	0

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INCOME STATEMENT

IS8016
YTD May 2025
06/07/2025 09:18

Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD May 2025	Kentucky Power Company - Distribution 110 Actual YTD May 2025	Kentucky Power Company - Generation 117 Actual YTD May 2025	Kentucky Power Company - Transmission 180 Actual YTD May 2025
5614001	PJM Admin-SSC&DS-Internal	630,673	0	630,673	0
5615000	Reliability,Plng&Stds Develop	48,270	711	99	47,460
5618000	PJM Admin-RP&SDS-OSS	9,446	0	9,446	0
5618001	PJM Admin-RP&SDS- Internal	176,800	0	176,800	0
5620001	Station Expenses - Nonassoc	131,141	6,898	0	124,243
5630000	Overhead Line Expenses	6,463	0	0	6,463
5650002	Transmssn Elec by Others-NAC	44,648	0	44,648	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	36,060,334	0	0
5650012	PJM Trans Enhancement Charge	863,223	0	863,223	0
5650015	PJM TO Serv Exp - Aff	71,093	0	71,093	0
5650016	PJM NITS Expense - Affiliated	31,664,851	0	31,664,851	0
5650019	Affil PJM Trans Enhncement Exp	1,994,253	0	1,994,253	0
5650020	PROVISION RTO Affl Tran Expnse	(588,510)	0	(588,510)	0
5650021	PJM NITS Expense - Non-Affilia	468,172	0	468,172	0
5650023	Amort of PROVISION RTO Expense	3,969,760	0	3,969,760	0
5660000	Misc Transmission Expenses	291,490	(50,481)	2,146	339,825
5660011	Misc Transm Exp - Affiliate	1,465	0	0	1,465
5670001	Rents - Nonassociated	250	0	0	250
5670002	Rents - Associated	0	0	0	170,018
	Transmission Op Exp	**40,982,450**	**36,035,857**	**39,345,278**	**1,831,666**
5800000	Oper Supervision & Engineering	772,364	770,068	154	2,165
5810000	Load Dispatching	1,827	1,827	0	0
5820000	Station Expenses	131,295	132,100	0	(805)
5830000	Overhead Line Expenses	591,222	591,479	(0)	(13)
5840000	Underground Line Expenses	175,957	175,410	0	546
5850000	Street Lighting & Signal Sys E	7,761	7,763	0	0
5860000	Meter Expenses	512,900	512,896	1	460
5870000	Customer Installations Exp	66,809	66,837	0	4
5880000	Miscellaneous Distribution Exp	1,206,525	1,203,630	151	3,213
5890001	Rents - Nonassociated	456,674	456,674	0	0
5890002	Rents - Associated	46,371	46,371	0	0
	Distribution Op Exp	**3,969,704**	**3,965,055**	**306**	**5,570**
9010000	Supervision - Customer Accts	9,735	9,746	(3)	(8)
9020000	Meter Reading Expenses	23,443	23,444	0	0
9020002	Meter Reading - Regular	165,148	165,261	0	0
9020003	Meter Reading - Large Power	12,608	12,608	0	0
9030000	Cust Records & Collection Exp	148,747	146,036	9	2,703
9030001	Customer Orders & Inquiries	1,142,110	1,142,024	38	61
9030002	Manual Billing	3,294	3,294	0	0
9030003	Postage - Customer Bills	262,620	262,620	0	0
9030004	Cashiering	23,126	23,126	0	0
9030005	Collection Agents Fees & Exp	1,495	1,495	0	0
9030006	Credit & Oth Collection Activi	185,323	185,391	4	26
9030007	Collectors	124,456	124,447	2	6
9030009	Data Processing	(313)	(315)	0	1
9040007	Uncoll Accts - Misc Receivable	(4,428)	(4,428)	0	0
9050000	Misc Customer Accounts Exp	13,162	13,162	0	0
9070000	Supervision - Customer Service	7,828	7,810	7	11
9080000	Customer Assistance Expenses	499,598	499,615	0	0
9080004	Cust Assistnce Exp - DSM - Ind	22	0	0	22
9080009	Cust Assistance Expense - DSM	369,518	369,518	0	0

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IS8016 YTD May 2025 06/07/2025 09:18	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD May 2025	YTD May 2025	YTD May 2025	YTD May 2025
9100000	Misc Cust Svc&Informational Ex	12,156	5,907	3,150	3,099
9100001	Misc Cust Svc & Info Exp - RCS	(98)	(52)	0	(46)
	Customer Service and Information Op Exp	**2,999,548**	**2,990,707**	**3,207**	**5,876**
9120000	Demonstrating & Selling Exp	2,926	2,922	0	4
9120003	Demo & Selling Exp - Area Dev	39	39	0	0
	Sales Expenses	**2,965**	**2,962**	**-**	**4**
	Memo: Insurance (9240 9250)	**1,115,106**	**544,161**	**445,674**	**125,271**
9200000	Administrative & Gen Salaries	4,769,877	2,520,959	1,521,402	727,527
9210001	Off Supl & Exp - Nonassociated	672,547	473,631	143,286	55,724
9210003	Office Supplies & Exp - Trnsf	64	22	29	13
9210020	EMP RECOG - Over 100 Dollars	24	8	11	5
9210021	EMP TRAVEL - Airfare	264	121	106	37
9210022	MEALS & ENT-100 Pct DEDUCTIBLE	83	37	38	8
9210023	EMP TRAVEL-MILEAGE	167	110	52	4
9210024	EMP TRAVEL-PARKING	73	32	37	4
9210025	MEALS & ENT-50 Pct DEDUCTIBLE	42	28	13	1
9210026	EMP TRAVEL-CAR RENTAL	17	9	6	1
9210027	EMP TRAVEL-TAXI AND SHUTTLE	27	13	11	3
9210028	EMP TRAVEL-HOTEL & LODGING	401	209	156	35
9210030	EMP TRAVEL-OTHER	60	21	27	13
9210032	FUEL	5	2	3	0
9210033	FOOD SERVICE-CATERING	34	11	15	7
9210034	In-House Training & Seminars	1,609	630	639	340
9210037	OEM/TECHNICAL TRAINING	317	0	317	0
9210040	DUES-BUSINESS/PROFESSIONAL	91	28	47	17
9210041	VEHICLE-LICENSE FEES	10	3	4	2
9220000	Administrative Exp Trnsf - Cr	(58,835)	(58,334)	0	(501)
9220001	Admin Exp Trnsf to Cnstrction	(194,086)	(194,086)	0	0
9220002	Admin Exp Trnsf Const-Mngerial	0	0	0	0
9220004	Admin Exp Trnsf to ABD	(230)	(230)	0	0
9220005	Overhead Loadings	(247,848)	(184,897)	(49,715)	(13,237)
9230001	Outside Svcs Empl - Nonassoc	904,630	218,109	375,077	311,444
9230003	AEPSC Billed to Client Co	(161,995)	(64,512)	(79,796)	(17,687)
9230031	SRV-OUTSIDE SERVICES (TECH)	141	47	63	30
9230034	SRV-SOFTWARE LICENSING	5,772	4,102	1,173	497
9230064	Def AEPSC Pension Settlement	3,464	1,242	1,108	1,114
9240000	Property Insurance	449,116	113,520	256,298	79,299
9250000	Injuries and Damages	815,711	561,274	208,808	45,628
9250002	Emp Accdent Prvntion-Adm Exp	(95)	(32)	(34)	(29)
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	(80,424)	(75,999)	(5,641)	1,216
9250007	Prsnal Injries&Prop Dmage-Pub	1,808	0	1,808	0
9250010	Frg Ben Loading - Workers Comp	(71,011)	(54,602)	(15,566)	(843)
9260000	Employee Pensions & Benefits	968	968	0	0
9260002	Pension & Group Ins Admin	9,021	4,130	4,751	139
9260003	Pension Plan	864,103	577,635	279,294	7,175
9260004	Group Life Insurance Premiums	58,309	38,468	19,251	590
9260005	Group Medical Ins Premiums	2,307,250	1,590,739	689,325	27,186
9260007	Group L-T Disability Ins Prem	181,704	105,007	76,449	249
9260009	Group Dental Insurance Prem	73,740	50,770	21,989	982
9260010	Training Administration Exp	396	213	139	45
9260012	Employee Activities	3,730	2,992	702	35

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IS8016 YTD May 2025 06/07/2025 09:18	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD May 2025	YTD May 2025	YTD May 2025	YTD May 2025
9260021	Postretirement Benefits - OPEB	31,484	17,608	13,369	508
9260027	Savings Plan Contributions	839,514	575,331	257,195	6,988
9260036	Deferred Compensation	9,525	9,525	0	0
9260037	Supplemental Pension	2,716	2,324	391	0
9260050	Frg Ben Loading - Pension	(423,910)	(362,911)	(51,233)	(9,766)
9260051	Frg Ben Loading - Grp Ins	(1,200,852)	(1,034,450)	(140,675)	(25,727)
9260052	Frg Ben Loading - Savings	(335,991)	(285,523)	(43,348)	(7,121)
9260053	Frg Ben Loading - OPEB	(17,122)	(13,017)	(3,526)	(579)
9260055	IntercoFringeOffset- Don't Use	(217,464)	(217,464)	0	0
9260058	Frg Ben Loading - Accrual	59,737	44,347	17,453	(2,063)
9270000	Franchise Requirements	66,845	66,845	0	0
9280000	Regulatory Commission Exp	8,998	3,870	2,712	2,416
9280002	Regulatory Commission Exp-Case	670,594	272,138	184,982	213,476
9280005	Reg Com Exp-FERC Trans Cases	36,993	31,241	27	5,725
9280006	State Publ Serv CommissionFees	397,165	397,165	0	0
9301000	General Advertising Expenses	11,825	8,020	1,886	1,919
9301001	Newspaper Advertising Space	4,561	2,019	1,264	1,278
9301003	TV Station Advertising Time	947	422	265	260
9301006	Spec Corporate Comm Info Proj	(1,683)	(1,683)	0	0
9301007	Special Adv Space & Prod Exp	625	625	0	0
9301012	Public Opinion Surveys	9,142	9,142	0	0
9301015	Other Corporate Comm Exp	3,283	3,283	0	0
9302000	Misc General Expenses	102,630	4,942	61,210	36,479
9302003	Corporate & Fiscal Expenses	29,481	19,366	8,152	1,962
9302004	Research, Develop&Demonstr Exp	18	18	0	0
9310001	Rents - Real Property	4,800	4,800	0	0
9310002	Rents - Personal Property	20,757	17,761	2,807	206
	Administration & General	**10,425,670**	**5,208,143**	**3,764,617**	**1,453,035**
4111005	Accretion Expense	969,234	7,915	961,318	0
	Accretion	**969,234**	**7,915**	**961,318**	**-**
4116000	Gain From Disposition of Plant	(6,881)	(6,881)	0	0
	Loss/(Gain) on Utility Plant	**(6,881)**	**(6,881)**	**-**	**-**
9302006	Assoc Bus Dev - Materials Sold	13,299	13,299	0	0
9302007	Assoc Business Development Exp	83,061	72,760	1	10,314
	Associated Business Development Expenses	**96,360**	**86,059**	**1**	**10,314**
4211000	Gain on Dspsition of Property	(53)	0	0	(53)
	Gain on Disposition of Property	**(53)**	**-**	**-**	**(53)**
	Loss on Disposition of Property	**-**	**-**	**-**	**-**
	Loss(Gain) of Sale of Property	**(53)**	**-**	**-**	**(53)**
4265009	Factored Cust A/R Exp - Affil	1,444,181	1,444,181	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	448,925	448,925	0	0
	Opr Exp and Factored A/R	**1,893,106**	**1,893,106**	**-**	**-**
	Water Heaters	**-**	**-**	**-**	**-**
4030047	Depr Exp - Cloud Computing	233,558	162,785	40,358	30,416
4265004	Social & Service Club Dues	39,551	2,149	37,402	0
4265007	Regulatory Expenses	1,320	585	372	363
	Expense of Non-Utility Operation	**274,429**	**165,519**	**78,131**	**30,779**
4210009	Misc Non-Op Exp - NonAssoc	106	106	(14)	14
	Misc NonOp Expenses - NonAssoc	**106**	**106**	**(14)**	**14**
4261000	Donations	707,957	702,242	2,648	3,067

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IS8016 YTD May 2025 06/07/2025 09:18	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD May 2025	YTD May 2025	YTD May 2025	YTD May 2025
	Donation Contributions	**707,957**	**702,242**	**2,648**	**3,067**
4263001	Penalties	24	8	11	5
	Provision for Penalties	**24**	**8**	**11**	**5**
4264000	Civic and Political Activity	78,519	38,119	20,265	20,138
4264001	Non-deduct Lobbying per IRS	13,244	3,964	6,783	2,497
	Civic & Political Activities	**91,763**	**42,083**	**27,048**	**22,634**
4265002	Other Deductions - Nonassoc	469,474	22,362	434,313	12,798
	Other Deductions	**469,474**	**22,362**	**434,313**	**12,798**
	Shutdown Coal Company Expenses	**-**	**-**	**-**	**-**
	All Other Operational Expenses	**3,436,859**	**2,825,426**	**542,137**	**69,298**
	Operational Expenses	**68,293,606**	**51,104,156**	**50,023,802**	**3,397,609**
5100000	Maint Supv & Engineering	458,818	0	458,818	0
5110000	Maintenance of Structures	733,626	0	733,626	0
5120000	Maintenance of Boiler Plant	7,277,693	0	7,277,693	0
5120034	BSDR O/U Recovery - Maint Cost	(2,681)	0	(2,681)	0
5120037	KY Steam Maint O/U	(291,356)	0	(291,356)	0
5130000	Maintenance of Electric Plant	2,376,001	0	2,376,001	0
5132000	Maint of Computer Software-Mjr	27,070	0	27,070	0
5133000	Maint of Comm Equipmt-Mjr	1,124	0	1,124	0
5140000	Maintenance of Misc Steam Plt	564,595	0	564,595	0
	Steam Generation Maintenance	**11,144,891**	**-**	**11,144,890**	**0**
5312000	Maint of Computer Software	0	0	(5)	5
	Nuclear Generation Maintenance	**-**	**-**	**(5)**	**5**
	Hydro Generation Maintenance	**-**	**-**	**-**	**-**
5587000	Maint Solar Pnl Strct & Eq-Mjr	4	1	2	1
	Other Generation Maintenance	**4**	**1**	**2**	**1**
5680000	Maint Supv & Engineering	3,215	47	376	2,792
5690000	Maintenance of Structures	19,858	0	0	19,858
5691000	Maint of Computer Hardware	1,202	8	5	1,189
5692000	Maint of Computer Software	48,253	8	51	48,194
5693000	Maint of Communication Equip	309	103	0	205
5700000	Maint of Station Equipment	317,768	(73)	1	317,840
5710000	Maintenance of Overhead Lines	2,215,148	0	16	2,215,137
5720000	Maint of Underground Lines	(61)	0	0	(61)
5730000	Maint of Misc Trnsmssion Plt	6,912	0	0	6,912
	Transmission Maintenance	**2,612,604**	**94**	**449**	**2,612,066**
5900000	Maint Supv & Engineering	49,631	49,651	0	(15)
5910000	Maintenance of Structures	7,660	7,658	0	2
5920000	Maint of Station Equipment	180,169	179,552	87	531
5923000	Maint of Computer Software-Mjr	46,260	46,260	0	0
5924000	Maint of Comm Equipmt-Mjr	374,865	374,865	0	0
5930000	Maintenance of Overhead Lines	15,469,383	15,573,270	(3)	(99,012)
5930001	Tree and Brush Control	156,758	156,842	0	0
5940000	Maint of Underground Lines	25,024	25,027	0	3
5950000	Maint of Lne Trnf,Rglators&Dvi	1,491	1,491	0	0
5960000	Maint of Strt Lghtng & Sgnal S	3,799	3,799	0	0
5970000	Maintenance of Meters	17,940	17,954	0	0
5980000	Maint of Misc Distribution Plt	10,435	10,435	1	(1)
	Distribution Maintenance	**16,343,415**	**16,446,805**	**84**	**(98,492)**
9350000	Maintenance of General Plant	2,592	2,591	1	0
9350001	Maint of Structures - Owned	91,346	90,914	170	262

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INCOME STATEMENT

IS8016
YTD May 2025
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Layout: IS8016
17A V2099-01-01 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

		Kentucky Power Int Consol IS8016 Actual YTD May 2025	Kentucky Power Company - Distribution 110 Actual YTD May 2025	Kentucky Power Company - Generation 117 Actual YTD May 2025	Kentucky Power Company - Transmission 180 Actual YTD May 2025
9350002	Maint of Structures - Leased	9,666	1,442	149	8,075
9350013	Maint of Cmmncation Eq-Unall	(318)	0	0	0
9351000	Maint of Computer Hardware	2,301	1,601	559	141
9352000	Maint of Computer Software	326,537	117,080	182,340	27,117
9353000	Maint of Comm Equipmt	55,691	46,257	9,353	80
	Administration & General Maintenance	**487,813**	**259,885**	**192,572**	**35,674**
	All Other Maintenance Expenses	**-**	**-**	**-**	**-**
	Maintenance Expenses	**30,588,726**	**16,706,785**	**11,337,993**	**2,549,254**
	Total Operational and Maintenance Expenses	**98,882,332**	**67,810,941**	**61,361,795**	**5,946,863**
4030046	Capitalized Software Depr Exp	3,615,541	1,890,247	1,096,892	628,402
4040001	Amort. of Plant	166,839	42,685	94,983	29,172
4060001	Amort of Plt Acq Adj	16,090	0	0	16,090
	DDA Amortization	**3,798,470**	**1,932,932**	**1,191,875**	**673,663**
4073014	Regulatory Debit - BSDR	86,754	0	86,754	0
	DDA Regulatory Debits	**86,754**	**-**	**86,754**	**-**
4074000	Regulatory Credits	(203,406)	(203,406)	0	0
4074025	PPA RIDER Over/Under	841,586	0	841,586	0
	DDA Regulatory Credits	**638,180**	**(203,406)**	**841,586**	**-**
	Amortization	**4,523,405**	**1,729,526**	**2,120,215**	**673,663**
4030001	Depreciation Exp	46,219,211	19,672,596	15,328,402	11,218,214
4030029	Over/Undr Depr Exp Var Riders	(589,520)	0	(589,520)	0
	DDA Depreciation	**45,629,691**	**19,672,596**	**14,738,882**	**11,218,214**
	DDA STP Nuclear Decommissioning	**-**	**-**	**-**	**-**
4031001	Depr - Asset Retirement Oblig	796,002	4,280	791,722	0
	DDA Asset Retirement Obligation	**796,002**	**4,280**	**791,722**	**-**
	DDA Removal Costs	**-**	**-**	**-**	**-**
	Depreciation	**46,425,693**	**19,676,875**	**15,530,604**	**11,218,214**
	Depreciation and Amortization	**50,949,098**	**21,406,402**	**17,650,819**	**11,891,877**
	Franchise Taxes	**-**	**-**	**-**	**-**
408100624	State Gross Receipts Tax	126	0	0	126
408100625	State Gross Receipts Tax	7,706	0	7,706	0
	Revenue-kWhr Taxes	**7,832**	**-**	**7,706**	**126**
4081002	FICA	1,563,205	1,086,341	462,925	13,939
4081003	Federal Unemployment Tax	11,748	7,071	4,413	264
4081007	State Unemployment Tax	20,849	7,136	13,524	189
4081033	Fringe Benefit Loading - FICA	(635,560)	(540,477)	(81,288)	(13,795)
4081034	Fringe Benefit Loading - FUT	(3,210)	(2,748)	(365)	(96)
4081035	Fringe Benefit Loading - SUT	(3,700)	(2,458)	(1,191)	(51)
	Payroll Taxes	**953,332**	**554,865**	**398,018**	**449**
408102021	State Business Occup Taxes	(224,843)	0	(224,843)	0
408102022	State Business Occup Taxes	(449,687)	0	(449,687)	0
408102023	State Business Occup Taxes	(534,125)	0	(534,125)	0
408102024	State Business Occup Taxes	(550,825)	0	(550,825)	0
408102025	State Business Occup Taxes	2,935,782	0	2,935,782	0
	Capacity Taxes	**1,176,302**	**-**	**1,176,302**	**-**
408100523	Real Personal Property Taxes	1,312,610	0	1,312,610	0
408100524	Real Personal Property Taxes	6,243,500	3,532,220	606,735	2,104,545
408102925	Real-Pers Prop Tax-Cap Leases	275,960	260,670	8,800	6,490
408103625	Real Prop Tax-Cap Leases	6,250	6,250	0	0

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IS8016 YTD May 2025 06/07/2025 09:18	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD May 2025	YTD May 2025	YTD May 2025	YTD May 2025
408200524	Real Personal Property Taxes	46,010	1,242	28,071	16,697
	Property Taxes	**7,884,330**	**3,800,382**	**1,956,216**	**2,127,732**
	Regulatory Fees	**-**	**-**	**-**	**-**
408101424	Federal Excise Taxes	1,073	0	1,073	0
408101425	Federal Excise Taxes	872	0	872	0
	Production Taxes	**1,945**	**-**	**1,945**	**-**
408101924	State Sales and Use Taxes	1,795	1,795	0	0
408101925	State Sales and Use Taxes	23,957	8,545	15,413	0
	Miscellaneous Taxes	**25,752**	**10,339**	**15,413**	**-**
	Other Non-Income Taxes	**27,697**	**10,339**	**17,358**	**-**
	Taxes Other Than Income Taxes	**10,049,494**	**4,365,586**	**3,555,600**	**2,128,307**
	TOTAL OPERATING EXPENSES	**159,880,924**	**93,582,928**	**82,568,215**	**19,967,047**
	Memo: SEC Total Operating Expenses	**283,054,755**	**280,107,457**	**205,741,993**	**19,967,068**
	OPERATING INCOME	**28,281,139**	**7,656,350**	**(40,616,898)**	**61,234,772**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	99,912	1,475	98,436	0
	Interest & Dividend NonAffiliated	**99,912**	**1,475**	**98,436**	**-**
4190005	Interest Income - Assoc CBP	137	137	0	0
	Interest & Dividend Affiliated	**137**	**137**	**-**	**-**
	Total Interest & Dividend Income	**100,049**	**1,612**	**98,436**	**-**
	Interest & Dividend Carrying Charge	**-**	**-**	**-**	**-**
	Memo: Total Interest & Dividend Income w/ Carrying	**100,049**	**1,612**	**98,436**	**-**
9260042	SERP Pension - Non-Service	(2,523)	(2,210)	(312)	0
9260043	OPEB - Non-Service	1,199,505	501,008	674,071	24,427
9260062	Pension Plan - Non-Service	1,047,016	106,004	982,194	(41,183)
9260064	Def AEPSC Pension Settlement	(476)	(184)	(292)	0
	Other Components of Net Periodic Pension	**2,243,522**	**604,617**	**1,655,661**	**(16,756)**
4191000	Allw Oth Fnds Usd Drng Cnstr	1,086,550	319,825	51,226	715,499
	AFUDC	**1,086,550**	**319,825**	**51,226**	**715,499**
	Gain on Disposition of Equity Investments	**-**	**-**	**-**	**-**
	Interest LTD FMB	**-**	**-**	**-**	**-**
4270002	Int on LTD - Install Pur Contr	(1,272,917)	(1,272,917)	0	0
	Interest LTD IPC	**(1,272,917)**	**(1,272,917)**	**-**	**-**
	Interest LTD Notes Payable - Affiliated	**-**	**-**	**-**	**-**
	Interest LTD Notes Payable - NonAffiliated	**-**	**-**	**-**	**-**
	Interest LTD Debentures	**-**	**-**	**-**	**-**
4270006	Int on LTD - Sen Unsec Notes	(23,139,271)	(23,139,271)	0	0
	Interest LTD Senior Unsecured	**(23,139,271)**	**(23,139,271)**	**-**	**-**
	Interest LTD Other - Affil	**-**	**-**	**-**	**-**
4270005	Int on LTD - Other LTD	(6,694,492)	(6,694,492)	0	0
	Interest LTD Other - NonAffil	**(6,694,492)**	**(6,694,492)**	**-**	**-**
	Interest on Long-Term Debt	**(31,106,680)**	**(31,106,680)**	**-**	**-**
4300003	Int to Assoc Co - CBP	(1,058,779)	14,626,990	(21,040,113)	5,354,345
	Interest STD - Affil	**(1,058,779)**	**14,626,990**	**(21,040,113)**	**5,354,345**
4310007	Lines Of Credit	(282,633)	(98,640)	(122,230)	(61,763)
	Interest STD - NonAffil	**(282,633)**	**(98,640)**	**(122,230)**	**(61,763)**

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American Electric Power

IS8016 YTD May 2025 06/07/2025 09:18	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD May 2025	YTD May 2025	YTD May 2025	YTD May 2025
	Interest on Short Term Debt	**(1,341,411)**	**14,528,349**	**(21,162,343)**	**5,292,582**
4280002	Amrtz Debt Dscnt&Exp-Instl Pur	(71,909)	(71,909)	0	0
4280003	Amrtz Debt Dscnt&Exp-N/P	(9,511)	(9,511)	0	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	(238,903)	(238,403)	(500)	0
	Amort of Debt Disc. Prem & Exp	**(320,323)**	**(319,823)**	**(500)**	**-**
4281004	Amrtz Loss Rcquired Debt-Dbnt	(14,021)	(14,021)	0	0
	Amort Loss on Reacquired Debt	**(14,021)**	**(14,021)**	**-**	**-**
	Amort Gain on Reacquired Debt	**-**	**-**	**-**	**-**
	Other Interest - Fuel Recovery	**-**	**-**	**-**	**-**
4310001	Other Interest Expense	5,570,767	6,360	5,557,697	6,710
4310002	Interest on Customer Deposits	(657,802)	(657,802)	0	0
9310005	Int on Regulated Fin Leases	(6,915)	0	0	0
	Other Interest - NonAffil	**4,906,050**	**(651,442)**	**5,557,697**	**6,710**
	Other Interest Expense - Affil	**-**	**-**	**-**	**-**
	Interest Rate Hedge Unrealized (Gain)/Loss	**-**	**-**	**-**	**-**
4320000	Allw Brrwed Fnds Used Cnstr-Cr	1,435,244	434,433	64,468	936,343
	AFUDC-Borrowed Funds	**1,435,244**	**434,433**	**64,468**	**936,343**
	Total Interest Charges	**(26,441,142)**	**(17,129,184)**	**(15,540,678)**	**6,235,636**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**5,270,118**	**(8,546,780)**	**(54,352,253)**	**68,169,151**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	2,046,948	(5,778,705)	(10,228,158)	18,053,811
4092001	Inc Tax, Oth Inc&Ded-Federal	(210,919)	(120,268)	(82,181)	(8,469)
	Federal Current Income Tax	**1,836,030**	**(5,898,974)**	**(10,310,339)**	**18,045,342**
4101001	Prov Def I/T Util Op Inc-Fed	21,581,588	6,808,706	12,119,900	2,652,982
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(21,100,607)	(2,565,308)	(13,193,283)	(5,342,017)
	Federal Deferred Income Tax	**480,981**	**4,243,398**	**(1,073,383)**	**(2,689,034)**
	Federal Investment Tax Credits	**-**	**-**	**-**	**-**
	Federal Income Taxes	**2,317,010**	**(1,655,576)**	**(11,383,722)**	**15,356,308**
4091002	Income Taxes, UOI - State	(1,267,988)	(1,604,056)	(2,645,305)	2,981,373
4092002	Inc Tax, Oth Inc & Ded - State	(52,970)	(30,204)	(20,639)	(2,127)
	State Current Income Tax	**(1,320,958)**	**(1,634,260)**	**(2,665,944)**	**2,979,246**
	State Deferred Income Tax	**-**	**-**	**-**	**-**
	State Investment Tax Credits	**-**	**-**	**-**	**-**
	State Income Taxes	**(1,320,958)**	**(1,634,260)**	**(2,665,944)**	**2,979,246**
	Local Current Income Tax	**-**	**-**	**-**	**-**
	Local Deferred Income Tax	**-**	**-**	**-**	**-**
	Local Investment Tax Credits	**-**	**-**	**-**	**-**
	Local Income Taxes	**-**	**-**	**-**	**-**
	Foreign Current Income Tax	**-**	**-**	**-**	**-**
	Foreign Deferred Income Tax	**-**	**-**	**-**	**-**
	Foreign Investment Tax Credits	**-**	**-**	**-**	**-**
	Foreign Income Taxes	**-**	**-**	**-**	**-**
	Total Income Taxes	**996,052**	**(3,289,835)**	**(14,049,666)**	**18,335,554**
	Equity Earnings of Subs	**-**	**-**	**-**	**-**
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	**4,274,066**	**(5,256,945)**	**(40,302,587)**	**49,833,597**
	Discontinued Operations (Net of Taxes)	**-**	**-**	**-**	**-**
	Cumulative Effect of Accounting Changes	**-**	**-**	**-**	**-**
	Extraordinary Income / (Expenses)	**-**	**-**	**-**	**-**

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IS8016 YTD May 2025 06/07/2025 09:18	INCOME STATEMENT	Kentucky Power Int Consol IS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
	Layout: IS8016				
17A V2099-01-01	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	YTD May 2025	YTD May 2025	YTD May 2025	YTD May 2025
	NET INCOME	**4,274,066**	**(5,256,945)**	**(40,302,587)**	**49,833,597**
	Minority Interest	**-**	**-**	**-**	**-**
	Preferred Stock Dividend Subs	**-**	**-**	**-**	**-**
	Earnings to Common Shareholders	**4,274,066**	**(5,256,945)**	**(40,302,587)**	**49,833,597**
	NET INCOME (LOSS) NODE before PS	**4,274,066**	**(5,256,945)**	**(40,302,587)**	**49,833,597**
	Double Check on Net Income Node after PS	(0)	(0)	-	-

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BS8216 YTD May 2025 06/10/2025 20:16	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD May 2025	YTD May 2025	YTD May 2025	YTD May 2025
	ASSETS				
	Cash and Cash Equivalents	**1,105,712**	**1,105,712**	**0**	**0**
	Other Cash Deposits	**22,976**	**12,667**	**10,042**	**267**
	Customers	19,894,105	16,771,493	650,509	2,472,103
	Accrued Unbilled Revenues	(4,325,041)	(4,442,472)	117,431	0
	Miscellaneous Accounts Receivable	20,965,248	5,326,806	55,586,605	20,176,145
	Allowances for Uncollectible Accounts	(372)	(372)	0	0
	Accounts Receivable	**36,533,941**	**17,655,455**	**56,354,545**	**22,648,247**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**82,649,391**	**6,061,981**	**73,908,010**	**2,679,400**
	Risk Management Contracts - Current	**3,015,258**	**0**	**3,015,258**	**0**
	Margin Deposits	**2,319,850**	**9,345**	**2,310,504**	**0**
	Unrecovered Fuel - Current	**3,738,643**	**0**	**3,738,643**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**1,595,572**	**1,326,386**	**174,059**	**95,127**
	TOTAL CURRENT ASSETS	**130,981,344**	**26,171,547**	**139,511,061**	**25,423,042**
	Electric Production	**1,292,162,662**	**1,357,682,946**	**1,326,066,455**	**967,865,183**
	Electric Transmission	**963,389,640**	**0**	**0**	**0**
	Electric Distribution	**1,224,198,683**	**0**	**0**	**0**
	General Property, Plant and Equipment	**173,021,134**	**83,276**	**(45,138)**	**1,119,396**
	Construction Work-in-Progress	**164,314,687**	**54,442,231**	**7,394,199**	**102,478,258**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,817,086,806**	**1,412,208,453**	**1,333,415,517**	**1,071,462,836**
	less: Accumulated Depreciation and Amortization	**(1,279,101,234)**	**(339,480,540)**	**(667,510,671)**	**(272,110,023)**
	NET PROPERTY, PLANT and EQUIPMENT	**2,537,985,572**	**1,072,727,913**	**665,904,846**	**799,352,813**
	Net Regulatory Assets	**625,170,227**	**155,101,726**	**459,665,134**	**10,403,367**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Assets	**39,411,824**	**17,691,466**	**20,897,254**	**823,104**
	Other Non Current Assets	**39,056,265**	**12,267,090**	**23,232,524**	**3,556,652**
	TOTAL OTHER NON-CURRENT ASSETS	**703,638,317**	**185,060,282**	**503,794,912**	**14,783,123**
	TOTAL ASSETS	**3,372,605,232**	**1,283,959,743**	**1,309,210,819**	**839,558,978**
	LIABILITIES				
	Accounts Payable	**112,514,279**	**99,456,035**	**55,629,841**	**17,552,710**
	Advances from Affiliates	**85,199,814**	**(729,524,840)**	**1,099,571,211**	**(284,846,558)**
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**300,000,000**	**300,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	177,718	10,976	166,742	0
2440021	S/T Liability MTM Collateral	(134,049)	(10,976)	(123,073)	0
	Risk Management Liabilities - MTM	43,669	0	43,669	0
	Risk Management Liabilities	**43,669**	**0**	**43,669**	**0**
	Accrued Taxes	**24,486,480**	**(15,542,419)**	**(41,616,305)**	**81,645,205**

BS8216 YTD May 2025 06/10/2025 20:16	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD May 2025	YTD May 2025	YTD May 2025	YTD May 2025
	Memo: Property Taxes	22,739,089	11,001,138	4,954,771	6,783,180
	Accrued Interest	**14,731,344**	**14,731,344**	**0**	**0**
	Risk Management Collateral	367,914	0	367,914	0
	Utility Customer Deposits	38,090,280	38,090,280	0	0
	Deposits - Customer and Collateral	**38,458,193**	**38,090,280**	**367,914**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	141,759	65,590	76,170	0
	Obligations under Operating Leases - Current	479,887	339,676	61,749	78,462
	Tax Collections Payable	2,022,562	2,022,562	0	0
	Revenue Refunds - Accrued	145,477	0	0	145,477
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	559,533	492,868	56,870	9,795
	Accrued Rents	(3,927)	(3,927)	0	0
	Accrued ICP	565,400	526,676	34,782	3,941
	Accrued Vacations	2,561,787	2,280,058	252,592	29,136
	Misc Employee Benefits	1,399,747	1,245,973	152,760	1,015
	Payroll Deductions	105,962	93,542	10,272	2,148
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	195,428	176,554	18,874	0
2530022	Customer Advance Receipts	2,308,679	2,308,679	0	0
	Customer Advance	2,308,679	2,308,679	0	0
2420511	Control Cash Disburse Account	927,151	927,151	0	0
	Control Cash Disbursement Account	927,151	927,151	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	163,541	0	163,541	0
2300002	ARO - Current	3,620,144	0	3,620,144	0
2420088	Econ. Development Fund Curr	768,020	768,020	0	0
2420512	Unclaimed Funds	16,001	16,001	0	0
2420542	Acc Cash Franchise Req	111,356	111,356	0	0
242059225	Sales Use Tax - Leased Equip	9,542	9,512	0	30
2420643	Accrued Audit Fees	76,160	49,527	16,624	10,009
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	470,153	468,254	0	1,899
2530112	Other Deferred Credits-Curr	48,277	47,752	525	0
2530124	Contr In Aid of Constr Advance	750,317	750,317	0	0
	Misc Current and Accrued Liabilities	6,034,196	2,221,424	3,800,834	11,938
	Current Other and Accrued Liabilities	16,821,995	12,291,561	4,326,985	203,449
	Other Current Liabilities	**17,443,642**	**12,696,827**	**4,464,904**	**281,911**
	TOTAL CURRENT LIABILITIES	**592,877,423**	**(280,092,772)**	**1,118,461,233**	**(185,366,732)**
	Long-Term Debt - Affiliated	**0**	**0**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,061,295,328**	**1,061,295,328**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(564,969)**	**(564,969)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,060,730,359*	*1,060,730,359*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	88,004	682	87,322	0
2440022	L/T Liability MTM Collateral	(682)	(682)	0	0
	Long-Term Risk Management Liabilities - MTM	87,322	0	87,322	0

BS8216 YTD May 2025 06/10/2025 20:16	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD May 2025	YTD May 2025	YTD May 2025	YTD May 2025
	Long-Term Risk Management Liabilities	**87,322**	**0**	**87,322**	**0**
	Deferred Income Taxes	**487,031,101**	**173,973,926**	**220,581,391**	**92,475,784**
	Deferred Investment Tax Credits	**0**	**0**	**0**	**0**
	Regulatory Liabilities and Deferred Credits	**126,401,260**	**94,538,896**	**(3,794,367)**	**35,656,732**
	Memo - Reg Liab and Def ITC	*126,401,260*	*94,538,896*	*(3,794,367)*	*35,656,732*
	Asset Retirement Obligation	**87,085,767**	**225,859**	**86,859,908**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**8,493,904**	**14,292,991**	**(7,612,255)**	**1,813,168**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redemption	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	839,811	715,267	124,544	0
	Obligations Under Operating Leases	3,220,652	2,800,618	153,254	266,779
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	101,503	101,503	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530044	Neigh Help Neig-Cust Donations	(15)	(15)	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	19,009	19,009	0	0
2530185	O\U Accounting of ExpensesT	4,735	0	4,735	0
2530188	Long Term Assoc AP	8,860,712	0	0	8,860,712
2530190	QUAL OF SVC PENALTIES - LT	72,870	0	0	72,870
	Def Credits - Other	8,957,311	18,994	4,735	8,933,582
	Total Other Deferred Credits	9,058,814	120,497	4,735	8,933,582
	Accumulated Provisions - Rate Refund	1,620,672	0	0	1,620,672
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**14,739,949**	**3,636,383**	**282,533**	**10,821,033**
	TOTAL NON-CURRENT LIABILITIES	**1,784,569,663**	**1,347,398,414**	**296,404,531**	**140,766,717**
	TOTAL LIABILITIES	**2,377,447,085**	**1,067,305,642**	**1,414,865,765**	**(44,600,014)**
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**526,038,123**	**106,025,371**	**335,469,573**	**84,543,179**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**418,670,024**	**88,224,681**	**(451,412,122)**	**781,857,466**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**995,158,147**	**216,654,101**	**(105,654,946)**	**884,158,992**
	Memo: Total Equity	995,158,147	216,654,101	(105,654,946)	884,158,992
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,372,605,232**	**1,283,959,743**	**1,309,210,819**	**839,558,978**
	out-of-balance	(0)	0	0	(0)

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BS8216 YTD May 2024 06/11/2024 14:17	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company · Distribution 110	Kentucky Power Company · Generation 117	Kentucky Power Company · Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD May 2024	YTD May 2024	YTD May 2024	YTD May 2024
	ASSETS				
	Cash and Cash Equivalents	**939,742**	**939,742**	**0**	**0**
	Other Cash Deposits	**39,370**	**17,496**	**21,256**	**618**
	Customers	14,442,571	12,077,520	629,319	1,735,731
	Accrued Unbilled Revenues	4,937,198	4,937,198	0	0
	Miscellaneous Accounts Receivable	16,782,633	3,572,743	54,966,693	16,739,662
	Allowances for Uncollectible Accounts	(67,122)	(67,006)	(4)	(111)
	Accounts Receivable	**36,095,281**	**20,520,455**	**55,596,009**	**18,475,282**
	Advances to Affiliates	**0**	**0**	**0**	**0**
	Fuel, Materials and Supplies	**98,693,965**	**6,867,073**	**88,695,666**	**3,131,227**
	Risk Management Contracts - Current	**1,704,137**	**0**	**1,704,137**	**0**
	Margin Deposits	**6,315,602**	**35,309**	**6,280,293**	**0**
	Unrecovered Fuel - Current	**2,672,228**	**0**	**2,672,228**	**0**
	Other Current Regulatory Assets	**0**	**0**	**0**	**0**
	Prepayments and Other Current Assets	**6,023,715**	**5,772,959**	**160,092**	**90,664**
	TOTAL CURRENT ASSETS	**152,484,040**	**34,153,033**	**155,129,681**	**21,697,791**
	Electric Production	**1,240,626,258**	**1,276,693,976**	**1,277,277,072**	**863,049,468**
	Electric Transmission	**858,516,645**	**0**	**0**	**0**
	Electric Distribution	**1,143,228,241**	**0**	**0**	**0**
	General Property, Plant and Equipment	**175,806,906**	**83,276**	(45,138)	**1,119,396**
	Construction Work-in-Progress	**176,304,846**	**59,456,622**	**24,683,913**	**92,164,311**
	TOTAL PROPERTY, PLANT and EQUIPMENT	**3,594,482,896**	**1,336,233,874**	**1,301,915,847**	**956,333,175**
	less: Accumulated Depreciation and Amortization	(1,230,481,564)	(325,396,449)	(642,534,765)	(262,550,349)
	NET PROPERTY, PLANT and EQUIPMENT	**2,364,001,333**	**1,010,837,425**	**659,381,082**	**693,782,826**
	Net Regulatory Assets	**552,109,601**	**129,605,558**	**414,051,704**	**8,452,338**
	Securitized Transition Assets and Other	**0**	**0**	**0**	**0**
	Spent Nuclear Fuel and Decommissioning Trusts	**0**	**0**	**0**	**0**
	Investments in Power and Distribution Projects	**0**	**0**	**0**	**0**
	Goodwill	**0**	**0**	**0**	**0**
	Long-Term Risk Management Assets	**283,270**	**0**	**283,270**	**0**
	Employee Benefits and Pension Assets	**25,790,881**	**13,593,254**	**11,436,239**	**761,388**
	Other Non Current Assets	**42,850,914**	**11,561,474**	**25,925,539**	**5,363,900**
	TOTAL OTHER NON-CURRENT ASSETS	**621,034,665**	**154,760,287**	**451,696,752**	**14,577,626**
	TOTAL ASSETS	**3,137,520,037**	**1,199,750,744**	**1,266,207,515**	**730,058,243**
	LIABILITIES				
	Accounts Payable	**86,585,959**	**83,060,841**	**50,686,452**	**11,335,132**
	Advances from Affiliates	**63,811,889**	(740,988,998)	**1,042,558,936**	(237,758,048)
	Short-Term Debt	**0**	**0**	**0**	**0**
	Other Current Regulatory Liabilities	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year Non-Affiliated	**215,000,000**	**215,000,000**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities - Hedge	0	0	0	0
2440001	Curr. Unreal Losses - NonAffil	3,926,627	15,221	3,911,406	0
2440021	S/T Liability MTM Collateral	(142,056)	(15,221)	(126,835)	0
	Risk Management Liabilities - MTM	3,784,571	0	3,784,571	0
	Risk Management Liabilities	**3,784,571**	**0**	**3,784,571**	**0**
	Accrued Taxes	**40,444,546**	**6,905,393**	(30,410,664)	**63,949,817**

BS8216 YTD May 2024 06/11/2024 14:17	BALANCE SHEET	Kentucky Power Int Consol	Kentucky Power Company · Distribution	Kentucky Power Company · Generation	Kentucky Power Company · Transmission
		BS8216	110	117	180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD May 2024	YTD May 2024	YTD May 2024	YTD May 2024
	Memo: Property Taxes	43,971,567	22,583,170	6,573,562	14,814,835
	Accrued Interest	**14,272,794**	**14,272,794**	**0**	**0**
	Risk Management Collateral	496,705	0	496,705	0
	Utility Customer Deposits	37,520,243	37,520,243	0	0
	Deposits - Customer and Collateral	**38,016,948**	**37,520,243**	**496,705**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	127,259	49,195	78,064	0
	Obligations under Operating Leases - Current	189,672	127,878	61,794	0
	Tax Collections Payable	2,014,032	2,014,032	0	0
	Revenue Refunds - Accrued	482,821	0	148,835	333,986
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	1,205,681	1,143,589	57,417	4,675
	Accrued Rents	2,491	2,491	0	0
	Accrued ICP	1,047,747	964,405	79,534	3,808
	Accrued Vacations	2,736,855	2,451,448	263,637	21,770
	Misc Employee Benefits	1,118,864	947,349	170,127	1,388
	Payroll Deductions	101,275	90,141	9,871	1,264
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	221,567	190,359	31,207	0
2530022	Customer Advance Receipts	2,949,384	2,949,384	0	0
	Customer Advance	2,949,384	2,949,384	0	0
2420511	Control Cash Disburse Account	561,081	561,081	0	0
	Control Cash Disbursement Account	561,081	561,081	0	0
	JMG Liability	0	0	0	0
2282011	Accm Prv I/D - Asbestos - Curr	118,665	0	118,665	0
2300002	ARO - Current	205,678	0	205,678	0
2420000	Misc Current & Accrued Liab	1,000,000	1,000,000	0	0
2420088	Econ. Development Fund Curr	715,681	715,681	0	0
2420512	Unclaimed Funds	19,358	19,358	0	0
2420542	Acc Cash Franchise Req	105,166	105,166	0	0
242059224	Sales Use Tax - Leased Equip	535	535	0	0
2420643	Accrued Audit Fees	143,194	60,236	54,067	28,892
2420700	Quality of Service	(0)	0	(0)	(0)
2420715	KY RPO Rider Liabilty	684	684	0	0
2530050	Deferred Rev -Pole Attachments	485,420	484,431	0	989
2530112	Other Deferred Credits-Curr	132,230	131,180	1,050	0
2530124	Contr In Aid of Constr Advance	160,607	160,607	0	0
	Misc Current and Accrued Liabilities	3,087,219	2,677,878	379,459	29,882
	Current Other and Accrued Liabilities	15,529,018	13,992,158	1,140,087	396,773
	Other Current Liabilities	**15,845,949**	**14,169,231**	**1,279,945**	**396,773**
	TOTAL CURRENT LIABILITIES	**477,762,656**	**(370,060,497)**	**1,068,395,945**	**(162,076,326)**
	Long-Term Debt - Affiliated	**25,000,000**	**25,000,000**	**0**	**0**
	Long-Term Debt - Non Affiliated	**1,060,696,240**	**1,060,696,240**	**0**	**0**
	Long-Term Debt - Premiums and Discounts Unamort	**(632,094)**	**(632,094)**	**0**	**0**
	Memo - LTD NonAffiliated and Premiums	*1,060,064,146*	*1,060,064,146*	*0*	*0*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	354,853	5,153	349,700	0
2440022	L/T Liability MTM Collateral	(5,153)	(5,153)	0	0

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BS8216 YTD May 2024 06/11/2024 14:17	BALANCE SHEET	Kentucky Power Int Consol BS8216	Kentucky Power Company - Distribution 110	Kentucky Power Company - Generation 117	Kentucky Power Company - Transmission 180
	Layout : BS8216				
18A V2099-01-01	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	YTD May 2024	YTD May 2024	YTD May 2024	YTD May 2024
	Long-Term Risk Management Liabilities - MTM	349,700	0	349,700	0
	Long-Term Risk Management Liabilities	**349,700**	**0**	**349,700**	**0**
	Deferred Income Taxes	**471,060,763**	**165,441,695**	**219,914,408**	**85,704,660**
	Deferred Investment Tax Credits	(0)	**0**	(0)	**0**
	Regulatory Liabilities and Deferred Credits	**105,456,270**	**79,148,573**	(4,905,592)	**31,213,289**
	Memo - Reg Liab and Def ITC	*105,456,270*	*79,148,573*	*(4,905,592)*	*31,213,289*
	Asset Retirement Obligation	**17,987,072**	**207,401**	**17,779,671**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**8,306,183**	**11,379,470**	(4,816,034)	**1,742,747**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Redemption	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	754,116	575,427	178,690	0
	Obligations Under Operating Leases	1,220,198	1,011,198	209,001	0
	Def Credits - Income Tax	0	0	0	0
	Def Credits - NSR	0	0	0	0
	Customer Advances for Construction	93,449	93,449	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	0	0	0	0
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	34,360	34,360	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	592	0	0	592
2530175	Legal Contingencies	(523)	(523)	0	0
2530185	O\U Accounting of ExpensesT	7,911	0	7,911	0
2530188	Long Term Assoc AP	4,355,998	0	0	4,355,998
2530190	QUAL OF SVC PENALTIES - LT	84,615	0	0	84,615
	Def Credits - Other	4,482,953	33,837	7,911	4,441,206
	Total Other Deferred Credits	4,576,403	127,286	7,911	4,441,206
	Accumulated Provisions - Rate Refund	790,591	0	0	790,591
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**7,341,308**	**1,713,910**	**395,602**	**5,231,797**
	TOTAL NON-CURRENT LIABILITIES	**1,695,565,443**	**1,342,955,196**	**228,717,755**	**123,892,492**
	TOTAL LIABILITIES	**2,173,328,099**	**972,894,698**	**1,297,113,700**	(38,183,834)
	Cumulative Pref Stocks of Subs - Not subject Mand Redemp	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**527,571,001**	**106,025,371**	**336,670,571**	**84,875,059**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**386,170,937**	**98,426,626**	(377,864,360)	**665,608,671**
	Accumulated Other Comprehensive Income (Loss)	**0**	**0**	**0**	**0**
	TOTAL SHAREHOLDERS' EQUITY	**964,191,938**	**226,856,046**	(30,906,185)	**768,242,077**
	Memo: Total Equity	964,191,938	226,856,046	(30,906,185)	768,242,077
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**3,137,520,037**	**1,199,750,744**	**1,266,207,515**	**730,058,243**
	out-of-balance	(0)	0	0	(0)

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KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - May, 2025

GLR7210 06/10/25 13:35

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,324,153,881.22	3,885,792.49	(2,568,116.53)	0.00	0.00	1,325,471,557.18
101/106	CLOUD GENERATION	446,948.71	67,981.93	(6,125.51)	0.00	0.00	508,805.13
	TOTAL PRODUCTION	**1,324,600,829.93**	**3,953,774.42**	**(2,574,242.04)**	**0.00**	**0.00**	**1,325,980,362.31**
101/106	TRANSMISSION	955,494,282.91	15,223,026.05	(2,852,126.35)	0.00	0.00	967,865,182.61
101/106	CLOUD TRANSMISSION	302,831.60	105,935.18	(1,258.48)	0.00	0.00	407,508.30
101/106	DISTRIBUTION	1,328,226,510.37	32,983,499.62	(5,183,407.18)	0.00	0.00	1,356,026,602.81
101/106	CLOUD DISTRIBUTION	2,053,474.66	366,580.99	(134,977.49)	0.00	0.00	2,285,078.16
	TOTAL (ACCOUNTS 101 & 106)	**3,610,677,929.47**	**52,632,816.26**	**(10,746,011.54)**	**0.00**	**0.00**	**3,652,564,734.19**
1011001/12	CAPITAL LEASES	1,329,493.17	0.00	0.00	120,077.43	0.00	1,449,570.60
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**3,612,007,422.64**	**52,632,816.26**	**(10,746,011.54)**	**120,077.43**	**0.00**	**3,654,014,304.79**
1050001	PLANT HELD FOR FUTURE USE	801,671.21	0.00	0.00	0.00	0.00	801,671.21
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEGINNING BALANCE	115,771,812.73					
107000X	ADDITIONS		100,635,192.71				
107000X	TRANSFERS		(52,092,318.16)				
107000X	ENDING BALANCE		48,542,874.55				164,314,687.28
107000X	**CLOUD CONSTRUCTION WIP:**						
107000X	BEGINNING BALANCE	1,813,515.61					
107000X	ADDITIONS		625,834.82				
107000X	TRANSFERS		(540,498.10)				
107000X	ENDING BALANCE		85,336.72				1,898,852.33
	TOTAL ELECTRIC UTILITY PLANT	**3,730,394,422.19**	**101,261,027.53**	**(10,746,011.54)**	**120,077.43**	**0.00**	**3,821,029,515.61**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	502,365.72	0.00	0.00	0.00	0.00	502,365.72
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1210003	NONUTILITY PROPERTY-WIP						
	BEGINNING BALANCE	0.00					
	ADDITIONS		0.00				
	TRANSFERS		0.00				
	ENDING BALANCE		0.00				0.00
1210016	NONUTILITY PROPERTY-CCNC	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	655,168.37	0.00	0.00	0.00	0.00	655,168.37
	TOTAL NONUTILITY PLANT	**1,157,534.09**	**0.00**	**0.00**	**0.00**	**0.00**	**1,157,534.09**

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KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - May, 2025

GLR7410 06/10/25 13:30

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
.	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	640,384,146.97	17,141,281.12	(2,574,242.04)	(793,172.91)	12,151,968.00	666,309,981.14
1080001/11	TRANSMISSION	302,596,611.20	11,788,304.83	(2,853,384.83)	(2,238,320.42)	4,549,736.60	313,842,947.38
1080001/11	DISTRIBUTION	407,529,530.89	21,292,058.66	(5,318,384.67)	(1,067,798.90)	15,289,461.01	437,724,866.99
1080026	CLOUD COMPUTE IMPLEMENT COST PRODUCTION	0.00	25,241.98	0.00	0.00	194,148.78	219,390.76
1080026	CLOUD COMPUTE IMPLEMENT COST TRANSMISSION	0.00	20,020.11	0.00	0.00	95,522.75	115,542.86
1080026	CLOUD COMPUTE IMPLEMENT COST DISTRIBUTION	0.00	101,883.83	0.00	0.00	658,855.33	760,739.16
1080013	PRODUCTION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	0.00	0.00	0.00	0.00	0.00	0.00
	RETIREMENT WORK IN PROGRESS	(14,227,110.14)	0.00	0.00	(6,842,133.35)	4,099,292.23	(16,969,951.26)
	TOTAL (108X accounts)	**1,336,283,178.93**	**50,368,790.53**	**(10,746,011.54)**	**(10,941,425.58)**	**37,038,984.70**	**1,402,003,517.04**
	NUCLEAR					0.00	
1110001	PRODUCTION	11,897,023.95	256,485.02	0.00	0.00	(12,153,508.95)	0.02
1110007	CLOUD IMPLEMENT COST PRODUCTION	185,158.67	7,449.15	0.00	0.00	(192,607.83)	(0.01)
1110001	TRANSMISSION	4,426,015.33	127,811.32	0.00	0.00	(4,553,826.66)	(0.01)
1110007	CLOUD IMPLEMENT COST TRANSMISSION	86,385.47	5,047.19	0.00	0.00	(91,432.69)	(0.03)
1110001	DISTRIBUTION	14,844,619.51	399,905.33	0.00	0.00	(15,185,450.73)	59,074.11
1110007	CLOUD IMPLEMENT COST DISTRIBUTION	732,931.68	29,933.90	0.00	0.00	(762,865.61)	(0.03)
	TOTAL (111X accounts)	**32,172,134.61**	**826,631.91**	**0.00**	**0.00**	**(32,939,692.47)**	**59,074.05**
1011006	CAPITAL LEASES	414,736.20	0.00	0.00	0.00	49,213.97	463,950.17
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**1,368,870,049.74**	**51,195,422.44**	**(10,746,011.54)**	**(10,941,425.58)**	**4,148,506.20**	**1,402,526,541.26**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	179,574.02	2,779.07	0.00	0.00	0.00	182,353.09
1220002	Depr&Amrt of Nonutl Prop-Leasd	0.00	0.00	0.00	0.00	0.00	0.00
1220003	Depr&Amrt of Nonutl Prop-WIP	0.00	0.00	0.00	0.00	0.00	0.00
1220004	Depletion - Owned	0.00	0.00	0.00	0.00	0.00	0.00
1240027	Other Property - RWIP	35,121.36	0.00	0.00	0.00	0.00	35,121.36
1240028	Other Property - Retirement	(46,947.27)	0.00	0.00	0.00	0.00	(46,947.27)
	TOTAL NONUTILITY PLANT	**167,748.11**	**2,779.07**	**0.00**	**0.00**	**0.00**	**170,527.18**

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U.S. Department of Energy
Energy Information Administration
Form EIA-826

Monthly Electric Utility Sales and Revenue Report with State Distributions – 2025

Form Approval
OMB NO.1905-0129
(Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**
Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650.

Utility Name: Kentucky Power Company

Identification Code (Assigned by EIA): 22053

Reporting for the month of: Jan___ Feb___ Mar___ Apr___ May_X__ Jun___ Jul___ Aug___ Sep___ Oct___ Nov___ Dec__ , 2025

Contact Person: Sandra Vargo

Phone number: 614-716-2671

Email: slvargo@aep.com

Fax: 614-716-1449

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	$ 14,854	$ 13,038	$ 14,509	$ -	$ 42,400
	b. Megwatthours	$ 87,139	$ 98,114	$ 169,045	-	354,298
	c. Number of consumers	$ 130,269	$ 30,624	$ 925	-	161,818
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					

Note: