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) Appalachian Power Company	Year/Period of Report End of: 2023/ 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 Appalachian Power Company	02 Year/ Period of Report End of: 2023/ 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, Ohio 43215-2373	
05 Name of Contact Person Jason M. Johnson	06 Title of Contact Person Accountant
07 Address of Contact Person (Street, City, State, Zip Code) AEP Service Corporation, 1 Riverside Plaza, Columbus, OH 43215-2373	

08 Telephone of Contact Person, Including Area Code (614) 716-1000	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 04/09/2024

Annual Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Jeffrey W. Hoersdig	03 Signature Jeffrey W. Hoersdig	04 Date Signed (Mo, Da, Yr) 04/09/2024
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: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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".

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Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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

1 Riverside PlazaColumbus, Ohio 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.

VirginiaMarch 4, 1926

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 - West VirginiaElectric - VirginiaElectric - Tennessee

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

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 the Common Stock.

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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)
1	Cedar Coal Company	Coal Mining - Inactive	100%	
2	Central Appalachian Coal Company	Coal Mining - Inactive	100%	
3	Central Coal Company	Coal Mining - Inactive	50%	[(a)] Footnote
4	Southern Appalachian Coal Company	Coal Mining - Inactive	100%	

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: FootnoteReferences
Central Coal Company is jointly controlled by Respondent and AEP Generation Resources, also a subsidiary of American Electric Power Company, Inc.

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

OFFICERS

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

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

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(a) Concept: OfficerTitle

Summary Compensation Table

The following table provides summary information concerning compensation earned by our Chief Executive Officer, our two Chief Financial Officers during 2023, the three other most highly compensated executive officers and one additional former executive officer whose compensation would have been among the three most highly compensated executive officers other than the CEO and CFOs if he had been an executive officer at year end. 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 ($)
Julia A. Sloat								
Chair of the Board, President and Chief Executive Officer	2023	1,200,000	—	8,321,524	787,503	210,263	114,555	10,633,745
Charles E. Zebula								
Executive Vice President and Chief Financial Officer	2023	639,625	—	2,852,248	240,500	181,438	73,170	3,986,981
David M. Feinberg								
Executive Vice President, General Counsel and Secretary	2023	746,000	— —	1,560,286	263,500	151,597	109,767	2,831,150
Christian T. Beam								
Executive Vice President - Energy Services	2023	585,000	—	1,248,229	220,500	123,014	170,900	2,347,643
Peggy I. Simmons								
Executive Vice President - Utilities	2023	585,000	—	1,248,229	220,500	86,652	87,482	2,227,863
Nicholas K. Akins								
Former Executive Chair of the Board	2023	862,500	—	2,000,000	696,149	729,068	359,384	4,647,101
Ann P. Kelly								
Former Executive Vice President and Chief Financial Officer	2023	525,000	250,000	2,042,588	—	—	550,866	3,368,454

(1) Amounts in the salary column are composed of executive salaries earned for the year shown, which include 260 days of pay for 2023, which is the number of workdays and holidays in a standard year.

(2) The amount in the bonus column for Ms. Kelly is a negotiated hire bonus paid in 2023 following her November 2022 hire into the EVP and CFO position.

(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, 2023 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 carbon free generation capacity additions (Carbon Free Additions 10%). The
grant date fair value of the 2023, 2022 and 2021 performance shares that are based on Cumulative EPS was computed in accordance with FASB ASC Topic 718 and was measured based on the closing price of AEP's common stock on the grant date. The maximum amount payable for the 2023 performance shares that are based on Cumulative EPS measured on the grant date is $3,000,000 for Ms. Sloat, $487,500 for Mr. Zebula, 562,500 for Mr. Feinberg, $450,000 for Mr. Beam, $450,000 for Ms. Simmons, $0 for Mr. Akins, and $652,495 for Ms. Kelly. The maximum amount payable for the 2023 performance shares that are based on Carbon Free Capacity additions is $600,000 for Ms. Sloat, $97,500 for Mr. Zebula, $112,500 for Mr. Feinberg, $90,000 for Mr. Beam, $90,000 for Ms. Simmons, $0 Mr. Akins, and $130,499 for Ms. Kelly. The grant date fair value of the 2023 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 2021 performance shares are included in the Option Exercises and Stock Vested for 2023 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 2023 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, 2023 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 2023 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, and (e) vacation payout. The 2023 values for these items are listed in the following table:

Type	Julia A. Sloat	Charles E. Zebula	David M. Feinberg	Christian T. Beam	Peggy I. Simmons	Nicholas K. Akins	Ann P. Kelly
Retirement Savings Plan Match	$ 14,85	$ 14,85	$ 14,85	$ 14,85	$ 14,85	$ 14,85	$ 14,85
Supplemental Retirement Savings Plan Match	84,297	45,565	54,917	30,349	22,275	188,169	7,043
Relocation	—	—	—	111,156	35,812	—	238,006
Perquisites	15,308	12,755	40,000	14,545	14,545	20,632	264,717
Vacation Payout	—	—	—	—	—	135,733	26,250
Total	**$ 114,45**	**$ 73,17**	**$ 109,76**	**$ 170,90**	**$ 87,48**	**$ 359,38**	**$ 550,86**

Perquisites provided in 2023 included: financial counseling and tax preparation services and, for Ms. Sloat and Mr. Akins, director's group travel accident insurance premium. Executive officers may also have the occasional personal use of event tickets when such tickets are not being used for business purposes, however, there is no associated incremental cost. From time-to-time executive officers may receive customary gifts from third parties that sponsor events (subject to our policies on conflicts of interest).

Provided Ms. Kelly complies with the terms of her Executive Severance, Noncompetition and Release of All Claims Agreement, she will receive $1,260,000 in cash severance benefits and up to $15,650 in outplacement services in 2024 in connection with her 2023 separation from AEP employment.

Ms. Sloat and Mr. Akins prior to his retirement were parties to Aircraft Time Sharing Agreements with the Company that allowed her or him to use our corporate aircraft for personal use for a limited number of hours each year. As required under these Aircraft Time Sharing Agreement Ms. Sloat and Mr. Akins to reimbursed the Company for the cost of her or his personal use of corporate aircraft in accordance with limits set forth in Federal Aviation Administration regulations. Ms. Sloat and Mr. Akins reimbursed the Company all incremental costs incurred in connection with personal flights under their Aircraft Timesharing Agreement including fuel, oil, hangar costs, crew travel expenses, catering, landing fees and other incremental airport fees. Accordingly, no value is shown for these amounts in the Summary Compensation Table. If the aircraft flew empty to pick up or after dropping off Ms. Sloat or Mr. Akins at a destination on a personal flight, the cost of the empty flight was included in the incremental cost for which Ms. Sloat or Mr. Akins was required to reimburse the Company.

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	Julia A. Sloat, Chair of the board and Chief Executive Officer	Columbus, Ohio	false	false
2	Christian T. Beam, Vice President	Columbus, Ohio	false	false
3	Paul Chodak, Vice President	Columbus, Ohio	false	false
4	David M. Feinberg, Vice President and Secretary	Columbus, Ohio	false	false
5	Ann P. Kelly, Vice President and Chief Financial Officer	Columbus, Ohio	false	false
6	Therace M. Risch, Vice President	Columbus, Ohio	false	false
7	Peggy I.Simmons, Vice President	Columbus, Ohio	false	false
8	Toby L. Thomas, Vice President	New Albany, Ohio	false	false
9	Rajagopalan.Sundararajan, Vice President	Columbus, Ohio	false	false
10	Phillip R.Ulrich,Vice President	Columbus, Ohio	false	false
11	Aaron D.Walker, President and Chief Operating Officer	Charleston, WV	false	false
12	Antonio P.Smyth, Vice President	Columbus, Ohio	false	false
13	Charles E.Zebula, Vice President and Chief Financial Officer	Columbus, Ohio	false	false
14	Note: The Respondent does not have an Executive Committee.			

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	20231218-5307	12/18/2023	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
2	20231031-5276	10/31/2023	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
3	20230525-5176	05/25/2023	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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 (full name)	Period of Franchise & Termination (month/day/year)	Consideration ($ amount or "None")
Automatic Renewal on October, 2023	Town of Glade Spring, Washington County, VA	Thirty (30) years expiring October 2, 2053	$1,475

equired

3.) None

4.) None

None

$6,263,523 Letter of Credit issued by American Electric Power Company, Inc. on behalf of Appalachian Power Company to benefit Nat'l Institute of Stds & Tech.

None

368 Appalachian Power Company employees in WV and VA represented by IBEW #978 were provided with a 3.5% wage increase effective April 1, 2023.

42 Appalachian Power Company employees in TN and VA represented by IBEW #934 were provided with a 3.5% wage increase effective April 1, 2023.

151 Appalachian Power Company employees at John Amos Plant represented by USW #8621 were provided with a 3.5% wage increase and contract effective May 1, 2023.

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

None

13.) Julia A Sloat elected Chairman of the Board and Chief Executive Officer 1/1/2023.

Timothy C Kerns elected as Vice President - Generation Assets effective on 04/03/2023.

Antonio P Smyth elected as Director effective on 04/12/2023.

Dana M Koenig elected as Assistant Vice President - Tax effective on 04/11/2023.

Kate Sturgess elected as Chief Accounting Officer and Controller effective on 05/09/2023.

Joseph M Buonaiuto resigned as Chief Accounting Officer and Controller effective on 05/08/2023.

Michael J Zwick resigned as Vice President - Generation Assets effective on 04/01/2023.
Rajagopalan Sundararajan resigned as Director effective on 04/05/2023.
Peggy I Simmons elected as Vice President effective on 08/18/2023.

Christian T Beam elected as Vice President effective on 08/18/2023.

Daniel E Mueller elected as Assistant Vice President - Tax effective on 09/28/2023 and resigned as Assistant Vice President-Tax effective on 08/18/2023.

Paul Chodak III resigned Vice President effective on 08/18/2023 and as director effective on 07/26/2023.

Eric J James resigned as Vice President effective on 08/18/2023.

Scott N Smith resigned as Vice President effective on 07/14/2023.

Thomas D Presthus resigned as Vice President effective on 08/18/2023.

Mark J Leskowitz resigned as Vice President effective on 08/18/2023.

Scott P Moore resigned as Vice President effective on 08/18/2023.

Therace M Risch resigned as Vice President effective on 08/18/2023.

Charles E Zebula resigned as Vice President effective on 08/18/2023.

Toby L Thomas resigned as Vice President effective on 08/18/2023 and director effective on 07/26/2023.

Phillip R Ulrich resigned as Vice President effective on 08/18/2023.

Ann P Kelly resigned as Chief Financial Officer, Vice President and Director effective on 09/29/2023.

harles E Zebula elected as Director, Chief Financial Officer and Vice President effective on 0/03/2023.

Proprietary capital ratio exceeds 30%

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	17,922,737,271	17,088,387,450
3	Construction Work in Progress (107)	200	718,224,524	711,076,450
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		18,640,961,795	17,799,463,900
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	6,446,565,009	6,119,554,019
6	Net Utility Plant (Enter Total of line 4 less 5)		12,194,396,786	11,679,909,881
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)		12,194,396,786	11,679,909,881
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		23,167,370	19,716,711
19	(Less) Accum. Prov. for Depr. and Amort. (122)		5,337,535	5,345,122
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	7,427,022	7,078,398
23	Noncurrent Portion of Allowances	228	9,862,780	22,901,397
24	Other Investments (124)		150,921,147	178,111,548
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)		168,569,346	149,639,072
30	Long-Term Portion of Derivative Assets (175)			
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		354,610,130	372,102,004
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		4,969,200	7,486,465
36	Special Deposits (132-134)		38,750,448	22,063,688
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		172,034,078	173,834,591
41	Other Accounts Receivable (143)		549,858	234,124
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,020,656	1,719,326
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		95,118,580	90,736,053
45	Fuel Stock (151)	227	303,375,126	151,723,238
46	Fuel Stock Expenses Undistributed (152)	227	11,642,310	7,213,740
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	148,114,642	130,152,009
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	10,115,774	23,345,718
53	(Less) Noncurrent Portion of Allowances	228	9,862,780	22,901,397
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)		9,950,637	8,271,859
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)		59,571	44,764
60	Rents Receivable (172)		1,343,072	1,463,031
61	Accrued Utility Revenues (173)		70,848,102	91,259,622
62	Miscellaneous Current and Accrued Assets (174)			
63	Derivative Instrument Assets (175)		22,416,859	69,090,847
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		877,404,821	752,299,026
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		27,810,578	30,972,977
70	Extraordinary Property Losses (182.1)	230a	72,019,648	75,567,634
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	1,533,576,138	1,757,037,534
73	Prelim. Survey and Investigation Charges (Electric) (183)		5,900,319	7,842,200
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		77,276	134,448
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	154,548,754	99,027,251
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		70,680,207	74,394,767
82	Accumulated Deferred Income Taxes (190)	234	468,207,184	497,096,485
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		2,332,820,104	2,542,073,295
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		15,759,231,842	15,346,384,206

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Page 110-111

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	260,457,768	260,457,768
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)			
7	Other Paid-In Capital (208-211)	253	1,834,533,776	1,828,635,966
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	3,189,120,237	2,894,696,533
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(3,463,213)	(3,463,213)
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(3,846,853)	(4,855,291)
16	Total Proprietary Capital (lines 2 through 15)		5,276,801,715	4,975,471,763
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	147,717,358	174,174,260
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	5,482,701,032	5,282,813,015
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		14,279,727	15,461,240
24	Total Long-Term Debt (lines 18 through 23)		5,616,138,663	5,441,526,034
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		77,597,155	80,754,270
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		2,795,571	2,914,692
29	Accumulated Provision for Pensions and Benefits (228.3)		10,254,067	10,715,639
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		9,595,923	18,532,621
32	Long-Term Portion of Derivative Instrument Liabilities		6,568,542	(74,470)
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		463,967,329	427,779,151
35	Total Other Noncurrent Liabilities (lines 26 through 34)		570,778,587	540,621,902
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		280,374,778	451,229,361
39	Notes Payable to Associated Companies (233)		339,616,792	182,155,076
40	Accounts Payable to Associated Companies (234)		121,259,642	142,594,329
41	Customer Deposits (235)		79,993,822	75,090,133
42	Taxes Accrued (236)	262	113,518,923	88,506,737
43	Interest Accrued (237)		58,866,464	57,935,097
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		4,615,416	4,735,041
48	Miscellaneous Current and Accrued Liabilities (242)		64,072,668	66,311,001
49	Obligations Under Capital Leases-Current (243)		22,846,476	22,838,869

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)		22,429,022	3,544,080
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		6,568,542	(74,470)
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)		1,101,025,461	1,095,014,194
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)			
57	Accumulated Deferred Investment Tax Credits (255)	266	284,659	295,219
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	59,055,687	33,465,774
60	Other Regulatory Liabilities (254)	278	650,529,101	766,020,836
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	122,439,909	130,828,743
63	Accum. Deferred Income Taxes-Other Property (282)		1,644,179,706	1,559,673,492
64	Accum. Deferred Income Taxes-Other (283)		717,998,354	803,466,246
65	Total Deferred Credits (lines 56 through 64)		3,194,487,416	3,293,750,310
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		15,759,231,842	15,346,384,203
	Page 112-113			

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	3,752,739,663	3,626,108,552			3,752,739,663	3,626,108,552				
3	Operating Expenses											
4	Operation Expenses (401)	320	2,117,465,403	1,947,769,256			2,117,465,403	1,947,769,256				
5	Maintenance Expenses (402)	320	271,804,900	297,919,962			271,804,900	297,919,962				
6	Depreciation Expense (403)	336	513,351,543	519,572,661			513,351,543	519,572,661				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	5,622,576	7,242,048			5,622,576	7,242,048				
8	Amort. & Depl. of Utility Plant (404-405)	336	49,012,146	44,876,903			49,012,146	44,876,903				
9	Amort. of Utility Plant Acq. Adj. (406)	336										
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		4,094,894	4,094,894			4,094,894	4,094,894				
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		29,295,754	35,244,275			29,295,754	35,244,275				
13	(Less) Regulatory Credits (407.4)		620,688	37,037,015			620,688	37,037,015				
14	Taxes Other Than Income Taxes (408.1)	262	162,651,640	157,876,769			162,651,640	157,876,769				
15	Income Taxes - Federal (409.1)	262	67,930,629	(54,522,666)			67,930,629	(54,522,666)				
16	Income Taxes - Other (409.1)	262	6,639,625	(124,453)			6,639,625	(124,453)				

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	316,232,823	480,566,371			316,232,823	480,566,371				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	325,264,096	403,636,935			325,264,096	403,636,935				
19	Investment Tax Credit Adj. - Net (411.4)	266	(9,420)	(9,420)			(9,420)	(9,420)				
20	(Less) Gains from Disp. of Utility Plant (411.6)		833,420	628,614			833,420	628,614				
21	Losses from Disp. of Utility Plant (411.7)		321,778				321,778					
22	(Less) Gains from Disposition of Allowances (411.8)		113	742,500			113	742,500				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		6,160,320	5,454,874			6,160,320	5,454,874				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		3,223,856,294	3,003,916,410			3,223,856,294	3,003,916,410				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		528,883,369	622,192,142			528,883,369	622,192,142				
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)											
34	(Less) Expenses of Nonutility Operations (417.1)		1,283	435								
35	Nonoperating Rental Income (418)		(13,066)	(127,209)								
36	Equity in Earnings of Subsidiary Companies (418.1)	119										
37	Interest and Dividend Income (419)		1,750,935	3,065,740								
38	Allowance for Other Funds Used During Construction (419.1)		11,864,280	11,692,346								
39	Miscellaneous Nonoperating Income (421)		753,463	942,659								
40	Gain on Disposition of Property (421.1)		(14,932)	13,695,255								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		14,339,397	29,268,356								
42	Other Income Deductions											

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)
43	Loss on Disposition of Property (421.2)		2,796,895	1,133,704								
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		511,272	13,706,762								
46	Life Insurance (426.2)											
47	Penalties (426.3)		133,546	52,256								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,381,044	1,732,368								
49	Other Deductions (426.5)		25,697,531	10,258,826								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		30,520,288	26,883,916								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	377,983	345,639								
53	Income Taxes-Federal (409.2)	262	(5,725,254)	(5,947,311)								
54	Income Taxes-Other (409.2)	262	(325,485)	(379,536)								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	10,078,236	5,867,151								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	55,397,531	3,062,324								
57	Investment Tax Credit Adj.-Net (411.5)		(1,140)	(2,295)								
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(50,993,191)	(3,178,676)								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		34,812,300	5,563,117								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		254,550,702	224,447,697								
63	Amort. of Debt Disc. and Expense (428)		4,353,854	4,358,897								
64	Amortization of Loss on Reaquired Debt (428.1)		3,714,560	3,798,575								
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)		16,797,094	5,565,782								
68	Other Interest Expense (431)		3,927,345	1,888,082								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		14,071,591	6,464,727								

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)
70	Net Interest Charges (Total of lines 62 thru 69)		269,271,964	233,594,306								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		294,423,705	394,160,953								
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)		294,423,705	394,160,953								
Page 114-117												

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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		2,875,610,549	2,518,949,597
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1	CECL adoption of ASC 326			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		294,423,704	394,160,952
17	Appropriations of Retained Earnings (Acct. 436)			
17.1	Appropriations of Retained Earnings (Acct. 436)		(562,756)	
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		(562,756)	
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			(37,500,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			(37,500,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		3,169,471,497	2,875,610,549
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)		19,648,740	19,085,984
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		19,648,740	19,085,984
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		3,189,120,237	2,894,696,533
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		(3,463,213)	(3,463,213)
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)		(3,463,213)	(3,463,213)

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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)	294,423,705	394,160,953
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	572,081,158	575,786,507
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Regulatory Debits and Credits	28,675,067	(1,792,739)
5.2	Customer Deposits	4,903,688	1,166,867
8	Deferred Income Taxes (Net)	(54,350,568)	79,734,263
9	Investment Tax Credit Adjustment (Net)	(10,560)	(11,715)
10	Net (Increase) Decrease in Receivables	(2,491,268)	29,528,615
11	Net (Increase) Decrease in Inventory	(174,043,091)	(112,942,532)
12	Net (Increase) Decrease in Allowances Inventory	156,803	(551,511)
13	Net Increase (Decrease) in Payables and Accrued Expenses	(99,793,937)	206,891,285
14	Net (Increase) Decrease in Other Regulatory Assets	(209,569,723)	(89,502,713)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(51,507,396)	44,363,447
16	(Less) Allowance for Other Funds Used During Construction	11,864,280	11,692,346
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):	[(a)](2,736,366)	(44,779,056)
18.2	Over/Under Recovered Fuel, net	433,991,923	(501,807,801)
18.3	Impairment of Long-Lived Assets		24,855,449
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	727,865,155	593,406,974
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(1,072,664,994)	(1,058,810,437)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	(3,356,466)	(7,253,727)
30	(Less) Allowance for Other Funds Used During Construction	(11,864,280)	(11,692,346)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
31.2	Acquired Assets	(10,677,337)	(953,330)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(1,074,834,518)	(1,055,325,148)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	[(b)]3,841,854	33,650,706
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	Contribution in Aid of Construction Proceeds	[c]4,174,247	9,814,905
53.2	(Increase) Decrease in other special deposits	(1,193,099)	6,513,339
53.3	Notes Receivable from Associated Companies		
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(1,068,011,516)	(1,005,346,197)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	200,000,000	704,375,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
64.2	Long-Term Issuance Costs	(9,943)	(6,345,387)
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Proceeds on Capital Leaseback	1,334,785	711,092
67.2	Notes Payable to Associates Companies	157,461,716	
67.3	Capital Contributions from Parent	5,897,810	9,015
70	Cash Provided by Outside Sources (Total 61 thru 69)	364,684,368	698,749,720
72	Payments for Retirement of:		
73	Long-term Debt (b)	(26,568,884)	(230,377,676)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Notes Payable to Associates Companies		(17,127,891)
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		(37,500,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	338,115,484	413,744,153
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)	(2,030,877)	1,804,929
88	Cash and Cash Equivalents at Beginning of Period	21,907,191	20,102,262
90	Cash and Cash Equivalents at End of Period	19,876,314	21,907,191
	Page 120-121		

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

	2023 Cash Flow Incr / (Decr)	2022 Cash Flow Incr / (Decr)
Utility Plant, Net	$ (57,068,187)	$ (88,831,417)
Property and Investments, Net	27,166,644	28,062,894
Margin Deposits	(15,007,275)	57,851,808
Mark-to-Market of Risk Management Contracts	65,558,931	(24,390,862)
Prepayments	(26,595,180)	(18,314,301)
Accrued Utility Revenues, Net	20,411,520	(37,246,622)
Miscellaneous Current and Accr Assets	—	—
Unamortized Debt Expense	3,172,341	2,905,050
Other Deferred Debits, Net	(45,860,717)	(283,895)
Proprietary Capital, Net	—	—
Other Comprehensive Income, Net	(834,597)	(834,932)
Unamortized Discount/Premium on Long-Term Debt	1,181,514	1,105,847
Accumulated Provisions - Misc	6,207,783	16,213,340
Current and Accrued Liabilities, Net	(21,614,200)	9,147,018
Other Deferred Credits, Net	40,545,057	9,837,016
Total	**$ (2,736,366)**	**$ (44,779,056)**

(b) Concept: ProceedsFromDisposalOfNoncurrentAssets

	2023 Cash Flow Incr / (Decr)	2022 Cash Flow Incr / (Decr)
Sale of transformers between various operating companies	$ 1,003,438	$ 774,729
Sale of meters between various operating companies	752,390	9,439,282
Sale of land to Vogel & Cromwell		3,569,774
Land Sale Buchanan County, Virginia, Grundy SC	1,468,500	—
Sale of Exciter Rotor and Stator	392,150	
Sale of spare GSU transformer		5,745,152
Transco Transfer of Assets	27,640	34,843
Adjust Sale of Meters (FEB)		(5,279)
Auction proceeds via incoming wire from Acquisition Title Sale		13,927,205
Sale of 1st Stage Turbine Bucket & Blade APCo Ceredo Plant to PSO Southwestern Plant	197,736	
One (1) E-Crane; 1500 Series B; Model 11264+ PD?E; S/N E071026?BE064?US		165,000
Total	**$ 3,841,854**	**$ 33,650,706**

(c) Concept: OtherAdjustmentsToCashFlowsFromInvestmentActivities

	2023 Cash Flow Incr / (Decr)	2022 Cash Flow Incr / (Decr)
CIAC Proceeds	$ 4,174,247	$ 9,814,905
Total	**$ 4,174,247**	**$ 9,814,905**

NOTES TO FINANCIAL STATEMENTS

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

INDEX OF NOTES TO FINANCIAL STATEMENTS

GLOSSARY OF TERMS FOR NOTES

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

Term	Meaning
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. APCo engages in the generation, transmission and distribution of electric power to retail customers in the southwestern portion of Virginia and southern West Virginia.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
CCR	Coal Combustion Residual.
CWIP	Construction Work in Progress.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE of AEP.
ELG	Effluent Limitation Guidelines.
ENEC	Expanded Net Energy Cost.
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.
FGD	Flue Gas Desulfurization or scrubbers.
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. I&M engages in the generation, transmission and distribution of electric power to retail customers in northern and eastern Indiana and southwestern Michigan.
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.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary. KGPCo provides electric service to retail customers in Kingsport, Tennessee and eight neighboring communities in northeastern Tennessee.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary. KPCo engages in the generation, transmission and distribution of electric power to retail customers in eastern Kentucky.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
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. OPCo engages in the transmission and distribution of electric power to retail customers in Ohio.
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.
PPA	Purchase Power and Sale Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary. PSO engages in the generation, transmission and distribution of electric power to retail customers in eastern and southwestern Oklahoma.
PTC	Production Tax Credit.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary. SWEPCo engages in the generation, transmission and distribution of electric power to retail customers in northeastern and panhandle of Texas, northwestern Louisiana and western Arkansas.
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.
TCA	Transmission Coordination Agreement dated January 1, 1997, by and among, PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two public utility subsidiaries.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary. WPCo provides electric service to retail customers in northern West Virginia.
WVPSC	Public Service Commission of West Virginia.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, APCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 967,000 retail customers in its service territory in southwestern Virginia and southern West Virginia. APCo sells power at wholesale to municipalities.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including APCo, 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

APCo's rates are regulated by the FERC, the Virginia SCC and the WVPSC. The FERC also regulates APCo'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 the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. The state regulatory commissions also regulate certain intercompany transactions under various orders and 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 and wholesale power transactions. APCo's wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when a cost-based contract is negotiated and filed with the FERC or the FERC determines that APCo has "market power" in the region where the transaction occurs. Wholesale power supply contracts have been entered into with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued-up to actual costs annually.

The Virginia SCC and the WVPSC regulate all of the retail distribution operations and rates of APCo's retail public utility subsidiaries on a cost basis. They also regulate the retail generation/power supply operations and rates.

The FERC also regulates APCo's wholesale transmission operations and rates. Retail transmission rates are based upon the FERC OATT rate when retail rates are unbundled in connection with restructuring. Retail transmission rates are based on formula rates included in the PJM OATT that are cost-based and are unbundled in Virginia. Bundled retail transmission rates are regulated, on a cost basis, by the Virginia SCC and the WVPSC.

In West Virginia, APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a combined cost-of-service basis.

In addition, the FERC regulates the Operating Agreement, TA and TCA, all of 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 14 - Related Party Transactions for additional information.

Basis of Accounting

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

- Accounting for subsidiaries on an equity basis.
- The classification of deferred fuel as noncurrent rather than current.
- The requirement to report deferred tax assets and liabilities separately rather than as a single amount.
- The classification of accrued taxes as a single amount rather than as assets and liabilities.
- The exclusion of current maturities of long-term debt from current liabilities.
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of capital 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 capital 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 accumulated deferred investment tax credits in deferred credits rather than in regulatory liabilities and deferred investment tax credits.
- The classification of deferred equity income in other deferred credits rather than in other non-current assets as securitized transition assets.
- The classification of amortization of deferred equity in operating revenues rather than in depreciation and amortization.
- The classification of certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.
- The classification of debt issuance costs as noncurrent assets instead of noncurrent liabilities.
- The classification of rents receivable as rents receivable instead of customer accounts receivable.
- The classification of Non-Service Cost Components of Net Periodic Benefit Cost as Operating Expense instead of Other Income (Expense).
- The classification of operating lease assets as Utility Plant rather than as a noncurrent asset.
- The presentation of obligations under finance and operating leases as a single amount in Obligations Under Capital Leases rather than as separate items.
- The classification of certain expenses in operating income rather than operating expenses.
- The classification of interest on regulated finance leases as operating expense instead of Other Income (Expense).
- The classification of certain write offs as depreciation expense rather than as operating expenses.
- The classification of cloud computing implementation costs as Utility Plant rather than as a noncurrent asset.
- The classification of accelerated depreciation caused by regulatory orders as accumulated depreciation rather than regulatory liabilities.
- The classification of expenses and revenues caused by regulatory orders as depreciation expense rather than operating revenues.
- The classification of the amortization of certain regulatory assets as regulatory debits and credits rather than operating expenses.
- The classification of the amortization of excess SO_2 allowances as current and accrued assets rather than noncurrent assets.

Accounting for the Effects of Cost-Based Regulation

APCo'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," regulatory assets (deferred expenses) 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 income with its passage to customers in cost-based regulated rates.

Use of Estimates

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

Cash and Cash Equivalents

Cash and Cash Equivalents include Cash, Working Fund and Temporary Cash Investments on the balance sheets with original maturities of three months or less.

Supplementary Information

	2023	2022
For the Years Ended December 31,		
Cash was Paid (Received) for:		
Interest (Net of Capitalized Amounts)	$ 259.4	$ 214.9
Income Taxes (Net of Refunds)	47.6	(88.2)
Noncash Acquisitions Under Finance Leases	5.0	1.6
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	100.7	164.6

Special Deposits

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

Inventory

Fossil fuel 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 over time as the performance obligations of delivering energy to customers are satisfied. To the extent that deliveries have occurred but a bill has not been issued, APCo accrues and recognizes, as Accrued Utility Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from bank conduits for a portion of its interests in the billed and unbilled receivables acquired from the affiliated utility subsidiaries. See "Securitized Accounts Receivable – AEP Credit" section of Note 13 for additional information.
Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from APCo. The assessment is performed by APCo, which inherently contemplates any differences in geographical risk characteristics for the allowance for uncollectible accounts. For receivables related to APCo's West Virginia operations, the allowance for uncollectible accounts is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable.

For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for potential credit losses at a specific counterparty level basis. For miscellaneous accounts receivable, bad debt expense is recognized based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable, unless specifically identified.

In addition to these processes, management contemplates available current information, as well as any reasonable and supportable forecast information, to determine if allowances for uncollectible accounts should be further adjusted in accordance with the accounting guidance for "Credit Losses." Management's assessments contemplate expected losses over the life of the accounts receivable.

Concentrations of Credit Risk and Significant Customers

APCo does not have any significant customers that comprise 10% or more of its operating revenues.

APCo monitors credit levels and the financial condition of its customers on a continuous basis to minimize credit risk. The regulatory commissions allow recovery in rates for a reasonable level of bad debt costs. Management believes adequate provisions for credit loss have been made in the accompanying financial statements.

Renewable Energy Credits

In regulated jurisdictions, APCo records renewable energy credits (RECs) at cost. APCo follows the inventory model for these RECs. RECs are reported in Miscellaneous Current and Accrued Assets on the balance sheets. The purchases and sales of RECs are reported in the Operating Activities section of the statements of cash flows. RECs that are consumed to meet applicable state renewable portfolio standards are recorded in Operation Expenses at an average cost on the statements of income. The net margin on sales of RECs affects the determination of deferred fuel and REC cost.

Property, Plant and Equipment

Electric utility property, plant and equipment for rate-regulated operations 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 charged to accumulated depreciation. 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.

Subsidiary Companies

APCo has three wholly-owned coal company subsidiaries, Cedar Coal Company, Central Appalachian Coal Company and Southern Appalachian Coal Company and one jointly owned subsidiary, Central Coal Company. The coal companies were formerly engaged in coal-mining operations and currently lease and sublease portions of their coal rights and land to nonaffiliated companies. Investment in the net assets of the coal company subsidiaries is carried at cost plus equity in their undistributed earnings since acquisition.

Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo, was formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance and is consolidated in APCo's financial statements.

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

APCo 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 and certain coal-mining facilities. APCo 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 APCo plans to use their facilities indefinitely. The retirement obligation would only be recognized if and when APCo abandons or ceases the use of specific easements, which is not expected.

Valuation of Nonderivative Financial Instruments

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

Fair Value Measurements of Assets and Liabilities

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

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

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan. 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 benefit 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 purchased electricity, 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 Virginia SCC's and the WVPSC's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the Virginia SCC and the WVPSC. On a routine basis, the Virginia SCC and the WVPSC review and/or audit APCo'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. APCo shares the majority of its Off-system Sales margins to customers either through an active FAC or other rate mechanisms. Where the FAC or Off-system Sales sharing mechanism is capped, frozen, or non-existent, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

APCo'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, assets are recorded on the 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, the regulatory asset is derecognized as a charge against income.

Retail and Wholesale Supply and Delivery of Electricity

APCo recognizes revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. APCo recognizes such revenues on the statements of income as the performance obligations of delivering energy to customers are satisfied. Recognized revenues include both billed and unbilled amounts.

Wholesale transmission revenue is based on FERC-approved formula rate filings 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. These annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations". An estimated annual true-up is recorded by APCo in the fourth quarter of each calendar year and a final annual true-up is recognized by APCo in the second quarter of each calendar year following the filing of annual FERC reports. Any portion of the true-ups 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 16 - Revenue from Contracts with Customers for additional information.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

Most of the power produced at the generation plants is sold to PJM. APCo also purchases power from PJM to supply power to customers. Generally, these power sales and purchases are reported on a net basis as 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 Operation Expenses on the statements of income.

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

In general, APCo records expenses when purchased electricity is received and when expenses are incurred. APCo defers unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

APCo engages in power, capacity and, to a lesser extent, natural gas marketing as a major power producer and participant in electricity and natural gas markets. APCo 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.

APCo 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 activities that are not derivatives are also recognized upon delivery of the commodity.

APCo 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 APCo's balance sheets as Derivative Instrument Assets or Liabilities, as
appropriate, and on the statements of income in Operating Revenues. APCo includes realized gains and losses on marketing and risk management transactions are included in revenue or expense based on the transaction's facts and circumstances. The 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 derivatives transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). In the event APCo 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, APCo 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 their statements of income. See "Accounting for Cash Flow Hedging Strategies" section of Note 9 for additional information.

Maintenance

APCo expenses maintenance costs as incurred. If it becomes probable that APCo will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with its recovery in cost-based regulated revenues. APCo defers costs above the level included in base rates and amortizes those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

APCo 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 required by a regulator to be 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.

APCo applies the deferral methodology for the recognition of ITCs. Deferred ITCs are amortized to income tax expense over the life of the asset that generated the credit. Amortization of deferred ITCs begins when the asset is placed in-service, except where regulatory commissions reflect ITCs in the rate-making process, then amortization begins when the utility is able to utilize the ITC on a stand-alone basis.

Transferable tax credits established by the IRA are accounted for in accordance with the accounting guidance for "Income Taxes" by APCo. Proceeds from sales of transferable tax credits are included as a component of Operating Activities on the statement of cash flows.

APCo accounts for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." APCo 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.

APCo joins in the filing of a consolidated federal income tax return. 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 to 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, APCo collects from customers certain excise taxes levied by those state or local governments on customers. APCo does not record 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 associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates.

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

Pension and OPEB Plans

APCo participates in an AEP sponsored qualified pension plan and an unfunded nonqualified pension plan. Substantially all APCo's employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. APCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees. APCo is allocated a proportionate share of benefit costs and account for their participation in these plans as multiple-employer plans. 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.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2023 through February 26, 2024, the date that AEP's Form 10-K was issued, and has updated such evaluation for disclosure purposes through April 9, 2024. 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 APCo's business. The following standard will impact APCo'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.

ASU 2023-07 "Improvements to Reportable Segment Disclosures" (ASU 2023-07)

In November 2023, the FASB issued ASU 2023-07, to address investors' observations that there is limited information disclosed about segment expenses and to better understand expense categories and amounts included in segment profit or loss. The new standard requires annual and interim disclosure of (a) the categories and amounts of significant segment expenses (determined by management using both qualitative and quantitative factors) that are regularly provided to the chief operating decision maker (CODM) and included within each reported measure of segment profit or loss, (b) the amounts and a qualitative description of "other segment items", defined as the difference between reported segment revenues less the significant segment expenses and each reported measure of segment profit or loss disclosed, (c) reportable segment profit or loss and assets that are currently only required annually, (d) the CODM's title and position, and an explanation of how the CODM uses the reported measure(s) of segment profit or loss in assessing segment performance and deciding how to allocate resources and (e) a requirement that entities with a single reportable segment provide all disclosures required by ASU 2023-07 and all existing segment disclosures in Topic 280. Additionally, this new standard allows disclosure of one or more of additional profit or loss measures if the CODM uses more than one measure provided that at least one of the disclosed measures is determined in a manner "most consistent with the measurement principles under GAAP". If multiple measures are presented, additional disclosure is required about how the CODM uses each measure to assess performance and decide how to allocate resources.

The amendments in the new standard are effective on a retrospective basis for all entities for fiscal years beginning after December 15, 2023 and interim periods within fiscal periods beginning after December 15, 2024 with early adoption permitted. Management does not plan to early adopt the amendments to this standard.

3. COMPREHENSIVE INCOME

APCo's balance and activity in AOCI was not material for the years ended December 31, 2023 and 2022.

4. RATE MATTERS

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

2020-2022 Virginia Triennial Review

In March 2023, APCo submitted its 2020-2022 Virginia triennial review filing and base rate case with the Virginia SCC as required by state law. APCo requested a $213 million annual increase in Virginia base rates based upon a proposed 10.6% return on common equity. The requested annual increase includes $47 million related to vegetation management and a $35 million increase in depreciation expense. The requested increase in depreciation expense reflects, among other things, the impacts of incremental investments made since APCo's last depreciation study using property balances as of December 31, 2022. Effective January 1, 2023 and in accordance with past Virginia SCC directives, APCo implemented updated Virginia depreciation rates. APCo's proposed revenue requirement also includes the recovery of certain costs incurred that partially contributed to APCo's calculated earnings shortfall for the 2020-2022 triennial period. For triennial review periods in which a Virginia utility earns below its authorized ROE band, the utility may file to recover expenses incurred, up to the bottom of the authorized ROE band, related to certain categories of costs, including system restoration costs for severe weather events.

In August 2023, APCo, Virginia Staff and intervening parties reached a settlement agreement that included the following: (a) a $127 million annual increase in Virginia base rates, (b) a 9.5% ROE, (c) updated depreciation rates that reflect a 2040 Amos Plant retirement date, (d) approval of a regulatory asset, including tax gross-up, to be recovered over three years starting in 2024 related to major storm expenses incurred during the 2020-2022 triennial period when APCo under-earned in Virginia, (e) approval of the revenue requirement impact of net operating loss carryforward related to income taxes and approval of deferral authority for corporate alternative minimum taxes incurred and (f) approval of the revenue requirement impact of an increase in vegetation management costs with certain costs subject to over-/under-recovery accounting. In November 2023, the Virginia SCC issued a final order approving the settlement agreement as described above with new rates taking effect in January 2024.

ENEC (Expanded Net Energy Cost) Filings

In April 2023, APCo and WPCo (the Companies) submitted their 2023 annual ENEC filing with the WVPSC, proposing two alternatives to increase ENEC rates effective September 1, 2023 and to resolve the Companies' open 2021 and 2022 ENEC filings. The first alternative was a $293 million annual increase in ENEC rates comprised of an $89 million increase for current year ENEC expense and a $200 million annual increase for the recovery of the Companies' February 28, 2023 ENEC under-recovery balances over three years, including debt and equity carrying costs. The second alternative was an $89 million annual increase in ENEC rates with the Companies securitizing approximately $1.9 billion of assets, including: (a) $553 million relating to ENEC under-recoveries as of February 28, 2023, (b) $88 million relating to major storm expense deferrals and (c) $1.2 billion relating to APCo's West Virginia jurisdictional book values of the Amos and Mountaineer Plants and forecasted CCR and ELG investments at these generating facilities.

In September 2023, the WVPSC issued an order on the 2023 ENEC filing approving an $89 million annual increase in ENEC surcharge rates for the Companies' forecasted costs for the period September 2023 through August 2024.

In January 2024, the WVPSC issued an order resolving the Companies' 2021-2023 ENEC cases. In the order, the WVPSC: (a) disallowed $232 million in ENEC under-recovered costs as of February 28, 2023 ($136 million related to APCo) and (b) approved the recovery of $321 million of ENEC under-recovered costs as of February 28, 2023 ($174 million related to APCo) plus a 4% carrying charge rate over a ten-year recovery period starting September 1, 2024. As of December 31, 2023, the Companies' financial statements reflect the impact of the disallowance. In February 2024, the Companies filed briefs with the West Virginia Supreme Court to initiate an appeal of this order. The Companies will submit their annual ENEC update filing with the WVPSC in the second quarter of 2024 proposing that updated ENEC rates become effective September 1, 2024.

FERC Rate Matters

FERC 2021 PJM and SPP Transmission Formula Rate Challenge

APCo and other AEP Subsidiaries transitioned to stand-alone treatment of NOLCs in its PJM and SPP transmission formula rates beginning with the 2022 projected transmission revenue requirements and 2021 true-up to actual transmission revenue requirements and provided notice of this change in informational filings made with the FERC. Stand-alone treatment of the NOLCs for transmission formula rates increased the annual revenue requirements for years 2023, 2022 and 2021 by $60 million, $69 million and $78 million, respectively.

In March 2023 and May 2023, certain joint customers submitted a complaint and a formal challenge at the FERC related to the 2022 Annual Update of the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP, respectively. These challenges primarily relate to stand-alone treatment of NOLCs in the transmission formula rates of the AEP transmission owning subsidiaries. AEPSC, on behalf of the AEP transmission owning subsidiaries within PJM and SPP, filed answers to the joint formal challenge and complaint with the FERC in the second quarter of 2023.

In January 2024, the FERC issued two orders, granting the joint customers' challenges related to stand-alone treatment of NOLCs in the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP. The FERC directed the AEP transmission owning subsidiaries within PJM and SPP to provide refunds with interest on all amounts collected for the 2021 rate year, and for such refunds to be reflected in the annual update for the next rate year. In February 2024, AEPSC on behalf of the AEP transmission owning subsidiaries within PJM and SPP filed requests with the FERC that it grant rehearing and reverse findings in its January 2024 orders or establish hearing procedures to address outstanding factual issues. In March 2024, the FERC denied AEPSC's requests for rehearing of the January 2024 orders by operation of law and stated it may address the requests for rehearing in future orders.

As a result of the January 2024 FERC orders, APCo and other AEP Subsidiaries' 2022 and 2023 income statements cumulatively reflect a provision for refund for the probable refund of all NOLC revenues included in transmission formula rates for years 2023, 2022 and 2021. The probable refunds to affiliated and nonaffiliated customers are reflected as Deferred Credits and Other Noncurrent Liabilities on the balance sheets. Refunds probable to be received by affiliated companies, resulting in a reduction to affiliated transmission expense, were deferred as an increase to Regulatory Liabilities or a reduction to Regulatory Assets on the balance sheets where management expects that refunds would be returned to retail customers through authorized retail jurisdiction rider mechanisms. The FERC directed cash refunds with interest related to the 2021 rate year to occur through the annual update for the next rate year, which will be invoiced by PJM and SPP primarily in 2025. APCo and other AEP Subsidiaries have not yet been directed to make cash refunds related to the 2022 or 2023 rate years.

The impact of the FERC's orders on the pretax net income of APCo was not material.

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 millions)		
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Income Tax Assets (a)	$ (4.2)	$ —	
Other Regulatory Assets Pending Final Regulatory Approval	0.6	7.0	
Total Regulatory Assets Currently Earning a Return	(3.6)	7.0	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs - West Virginia	91.5	72.6	
2020-2022 Virginia Triennial Under-Earnings	37.4	37.9	
Plant Retirement Costs - Asset Retirement Obligation Costs	25.9	25.9	
Other Regulatory Assets Pending Final Regulatory Approval	7.5	1.2	
Total Regulatory Assets Currently Not Earning a Return	162.3	137.6	
Total Regulatory Assets Pending Final Regulatory Approval	158.7	144.6	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Long-term Under-recovered Fuel Costs - West Virginia	154.2	—	11 years
Under-recovered Fuel Costs - Virginia	147.4	180.7	1 year
Long-term Under-recovered Fuel Costs - Virginia	107.0	223.3	2 years
Other Regulatory Assets Approved for Recovery	7.1	0.4	various
Total Regulatory Assets Currently Earning a Return	415.7	404.4	
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets (b)	369.9	375.4	
Plant Retirement Costs - Asset Retirement Obligation Costs	324.7	303.1	15 years
Pension and OPEB Funded Status	115.8	108.3	12 years
Virginia Transmission Rate Adjustment Clause	25.5	18.7	2 years
Unrealized Loss on Forward Commitments	21.9	—	3 years
Peak Demand Reduction/Energy Efficiency	15.0	15.8	3 years
Postemployment Benefits	14.9	13.7	3 years
Vegetation Management Program - West Virginia	12.9	13.7	2 years
Excess SO_2 Allowance Inventory - Virginia	11.8	—	9 years
Virginia Generation Rate Adjustment Clause	10.9	8.0	2 years
Virginia Clean Economy Act	8.0	16.7	2 years
Under-recovered Fuel Costs	8.0	292.4	1 year
2017-2019 Virginia Triennial Under-Earnings	2.3	30.1	1 year
Other Regulatory Assets Approved for Recovery	17.6	12.1	various
Total Regulatory Assets Currently Not Earning a Return	959.2	1,208.0	
Total Regulatory Assets Approved for Recovery	1,374.9	1,612.4	
Total FERC Account 182.3 Regulatory Assets	$ 1,533.6	$ 1,757.0	

(a) Represents an income tax related regulatory liability, which is presented within net regulatory assets on the balance sheet.
(b) Recovered over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets.

Regulatory Liabilities:	December 31, 2023	December 31, 2022	Remaining Refund Period
	(in millions)		
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
Income Taxes Liabilities	$ 3.7	$ —	
Total Regulatory Liabilities Currently Paying a Return	3.7	—	
Regulatory Liabilities Currently Not Paying a Return			
FERC 2021 Transmission Formula Rate Challenge Refunds	19.7	—	
Total Regulatory Liabilities Currently Not Paying a Return	19.7	—	
Total Regulatory Liabilities Pending Final Regulatory Determination	23.4	—	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Not Paying a Return			
Income Tax Liabilities (a)	610.0	697.1	(b)
Over-recovered Deferred Wind Power Costs - Virginia	2.6	13.6	2 years
Unrealized Gain on Forward Commitments	—	34.5	
Other Regulatory Liabilities Approved for Payment	14.5	20.8	various
Total Regulatory Liabilities Currently Not Paying a Return	627.1	766.0	
Total FERC 254 Account Regulatory Liabilities	$ 650.5	$ 766.0	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Recovered over the period for which the related deferred income 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 $35 million and $19 million for the years ended December 31, 2023 and 2022, respectively. The remaining balance of Excess ADIT that is Not Subject to Rate Normalization Requirements as of December 31, 2023 is to be refunded over 5 years.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

APCo is subject to certain claims and legal actions arising in the ordinary course of business. In addition, APCo'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 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

APCo has substantial commitments for fuel, energy and capacity contracts as part of the normal course of business. Certain contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following table summarizes APCo'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 millions)		
Fuel Purchase Contracts (a)	$ 595.2	$ 626.1	$ 99.5	$ —	$ 1,320.8
Energy and Capacity Purchase Contracts	40.1	80.2	65.5	75.9	261.7
Total	$ 635.3	$ 706.3	$ 165.0	$ 75.9	$ 1,582.5

(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.

Letters of Credit

Standby letters of credit are entered into with third-parties. These letters of credit are issued in the ordinary course of business and cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

AEP has $4 billion and $1 billion revolving credit facilities due in March 2027 and 2025, respectively, under which up to $1.2 billion may be issued as letters of credit on behalf of APCo. As of December 31, 2023, no letters of credit were issued under the revolving credit facility.

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $450 million. APCo's maximum future payments for letters of credit issued under the uncommitted facilities as of December 31, 2023 was $6 million with a maturity date of September 2024.

Indemnifications and Other Guarantees

Contracts

APCo 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.

Lease Obligations

APCo leases equipment under master lease agreements. See "Master Lease Agreements" section of Note 12 for additional information.

ENVIRONMENTAL CONTINGENCIES

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. APCo 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, APCo was named as a Potentially Responsible Party (PRP) for one site by the Federal EPA for which alleged liability is unresolved. There are 2 additional sites for which APCo received information requests which could lead to PRP designation. In those instances where a PRP or defendant has been named, 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 Superfund 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 as PRPs 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 identified Superfund sites.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

APCo maintains insurance coverage normal and customary for electric utilities, subject to various deductibles. APCo also maintains property and casualty insurance that may cover certain physical damage or third-party injuries caused by cybersecurity incidents. Insurance coverage includes all risks of physical loss or damage to nonnuclear 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 retentions absorbed by APCo. 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 cybersecurity 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.

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.

APCo participates in an AEPSC sponsored qualified pension plan and an unfunded nonqualified pension plan. Substantially all employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. APCo also participates in OPEB plans sponsored by AEPSC to provide health and life insurance benefits for retired employees.

APCo recognizes the 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. APCo 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. APCo records a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for ratemaking 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 the benefit obligations are shown in the following table:

	Pension Plans		OPEB	
	December 31,			
Assumption	**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	4.95 % (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 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 the average increase shown in the table above.

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,			
Assumption	**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	4.95 % (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**	**December 31, 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. Management monitors the plans 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, Funded Status and Amounts Recognized on the Balance Sheets

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 millions)			
Benefit Obligation as of January 1,	$ 484.1	$ 619.7	$ 122.1	$ 144.0
Service Cost	9.1	11.4	0.5	0.8
Interest Cost	26.3	17.4	6.4	4.0
Actuarial (Gain) Loss	22.7	(122.7)	1.9	(12.4)
Benefit Payments	(40.1)	(41.7)	(20.3)	(21.3)
Participant Contributions	—	—	6.6	7.0
Benefit Obligation as of December 31,	$ 502.1	$ 484.1	$ 117.2	$ 122.1
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 526.9	$ 677.6	$ 228.3	$ 302.0
Actual Gain (Loss) on Plan Assets	58.1	(109.0)	28.1	(59.4)
Participant Contributions	—	—	6.6	7.0
Benefit Payments	(40.1)	(41.7)	(20.3)	(21.3)
Fair Value of Plan Assets as of December 31,	$ 544.9	$ 526.9	$ 242.7	$ 228.3
Funded Status as of December 31,	$ 42.8	$ 42.8	$ 125.5	$ 106.2

Amounts Recognized on the Balance Sheets

	Pension Plans		OPEB	
	2023	**2022**	**2023**	**2022**
	(in millions)			
Special Funds – Prepaid Benefit Costs	$ 43.1	$ 43.4	$ 125.5	$ 106.2
Accumulated Provision for Pensions and Benefits – Long-term Benefit Liability	(0.3)	(0.6)	—	—
Funded Status	$ 42.8	$ 42.8	$ 125.5	$ 106.2

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

The following tables show the components of the plans included in Regulatory Assets, Deferred Income Taxes and AOCI:

	Pension Plans		OPEB	
	2023	**2022**	**2023**	**2022**
Components	(in millions)			
Net Actuarial Loss	$ 102.6	$ 93.6	$ 32.2	$ 44.6
Prior Service Credit	—	—	(4.2)	(13.3)
Recorded as				
Regulatory Assets	$ 102.6	$ 93.6	$ 13.2	$ 14.7
Deferred Income Taxes	—	—	3.1	3.5
Net of Tax AOCI	—	—	11.7	13.1

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

Components	Pension Plans 2023	Pension Plans 2022	OPEB 2023	OPEB 2022
	(in millions)			
Actuarial (Gain) Loss During the Year	$ 9.0	$ 18.3	$ (10.2)	$ 63.1
Amortization of Actuarial Loss	—	(7.2)	(2.2)	—
Amortization of Prior Service Credit	—	—	9.1	10.4
Change for the Year Ended December 31,	$ 9.0	$ 11.1	$ (3.3)	$ 73.5

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 APCo using the percentages in the table below:

Pension Plan		OPEB	
December 31,			
2023	2022	2023	2022
13.2 %	12.8 %	14.5 %	14.7 %

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:

Accumulated Benefit Obligation	December 31, 2023	2022
	(in millions)	
Qualified Pension Plan	$ 483.7	$ 468.6
Nonqualified Pension Plans	0.1	0.3
Total	$ 483.8	$ 468.9

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

	December 31, 2023	2022
	(in millions)	
Projected Benefit Obligation	$ 0.4	$ 0.6
Fair Value of Plan Assets	—	—
Underfunded Projected Benefit Obligation	$ (0.4)	$ (0.6)

Accumulated Benefit Obligation

	December 31, 2023	2022
	(in millions)	
Accumulated Benefit Obligation	$ 0.1	$ 0.3
Fair Value of Plan Assets	—	—
Underfunded Accumulated Benefit Obligation	$ (0.1)	$ (0.3)

Estimated Future Benefit Payments and Contributions

APCo expects contributions and payments for the Pension plans of $6 thousand 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 APCo'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 the pension benefits and OPEB are as follows:

Pension Plans	Estimated Payments Pension Plans	OPEB
	(in millions)	
2024	$ 43.7	$ 17.2
2025	43.1	17.8
2026	43.9	17.7
2027	42.4	17.6
2028	43.3	17.5
Years 2029 to 2033, in Total	199.3	81.5

Components of Net Periodic Benefit Cost

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

	Pension Plans		OPEB	
	Years Ended December 31,			
	2023	2022	2023	2022
	(in millions)			
Service Cost	$ 9.1	$ 11.4	$ 0.5	$ 0.8
Interest Cost	26.3	17.4	6.4	4.0
Expected Return on Plan Assets	(44.3)	(32.1)	(16.0)	(16.1)
Amortization of Prior Service Credit	—	—	(9.1)	(10.4)
Amortization of Net Actuarial Loss	—	7.2	2.2	—
Net Periodic Benefit Cost (Credit)	(8.9)	3.9	(16.0)	(21.7)
Capitalized Portion	(4.2)	(5.0)	(0.2)	(0.4)
Net Periodic Benefit Credit Recognized in Expense	$ (13.1)	$ (1.1)	$ (16.2)	$ (22.1)

American Electric Power System Retirement Savings Plan

APCo 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 company 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 to the retirement savings plan for the years ended December 31, 2023 and 2022 was $8 million and $8 million, respectively.

8. BUSINESS SEGMENTS

APCo has one reportable segment, an electricity generation, transmission and distribution business. APCo's other activities are insignificant.

9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of APCo.

APCo is exposed to certain market risks as major power producer and participant in the electricity, capacity, natural gas, coal and emission allowance markets. These risks include commodity price risks which may be subject to capacity risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact APCo 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, APCo 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.

APCo 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. APCo utilizes interest rate derivative contracts in order to manage the interest rate exposure associated with the commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. APCo also utilizes 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 established risk management policies as approved by the Finance Committee of the Board of Directors.

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

Notional Volume of Derivative Instruments

Primary Risk Exposure	2023	2022	Unit of Measure
	(in millions)		
Commodity:			
Power	16.8	17.9	MWhs
Natural Gas	37.3	1.9	MMBtus
Heating Oil and Gasoline	1.0	1.0	Gallons

Cash Flow Hedging Strategies

APCo 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. APCo does not hedge all commodity price risk.

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

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE 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 other assumptions. In order to determine the relevant fair values of the derivative instruments, APCo 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," APCo 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, APCo is required to post or receive cash collateral based on third-party contractual agreements and risk profiles. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets for APCo as of December 31, 2023 and 2022. The amount of cash collateral paid to third-parties netted against short-term and long-term risk management liabilities was not material for APCo as of December 31, 2023 and 2022.

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

Balance Sheet Location	December 31, 2023 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 millions)	
Derivative Instrument Assets	$ 24.9	$ (2.5)	$ 22.4
Long-Term Portion of Derivative Instrument Assets	0.3	(0.3)	—
Derivative Instrument Liabilities	25.4	(2.9)	22.5
Long-Term Portion of Derivative Instrument Liabilities	6.9	(0.3)	6.6

Balance Sheet Location	December 31, 2022 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 millions)	
Derivative Instrument Assets	$ 70.0	$ (0.9)	$ 69.1
Long-Term Portion of Derivative Instrument Assets	0.7	(0.7)	—
Derivative Instrument Liabilities	4.8	(1.1)	3.7
Long-Term Portion of Derivative Instrument Liabilities	0.7	(0.6)	0.1

(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 the 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 millions)	
Operating Revenues	$ 0.1	$ 0.5
Operation Expenses	2.3	4.9
Maintenance Expenses	(0.1)	0.9
Other Regulatory Assets (a)	(21.9)	(0.1)
Other Regulatory Liabilities (a)	1.0	82.4
Total Gain (Loss) on Risk Management Contracts	$ (18.6)	$ 88.6

(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 the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the 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), APCo 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 the statements of income or in Other Regulatory Assets or Other Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2023 and 2022, APCo did not apply cash flow hedging to outstanding power derivatives.

APCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income on the balance sheets into Interest on Long-term Debt on the statements of income in those periods in which hedged interest payments occur. During the years ended 2023 and 2022, APCo did not apply cash flow hedging to outstanding interest rate derivatives.

For details on effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges, see Note 3 - Comprehensive Income.

Cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets were:

Impact of Cash Flow Hedges on the Balance Sheets

December 31, 2023		December 31, 2022	
Interest Rate			
AOCI Gain Net of Tax	Expected to be Reclassed to Net Income During the Next Twelve Months	AOCI Gain Net of Tax	Expected to be Reclassed to Net Income During the Next Twelve Months
	(in millions)		
$ 5.9	$ 0.8	$ 6.7	$ 0.8

The actual amounts reclassified from Accumulated Other Comprehensive Income to Net Income can differ from the estimate above due to market price changes.

Credit Risk

Management mitigates credit risk in 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 a 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. APCo has not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. APCo had no derivative contracts with collateral triggering events in a net liability position as of December 31, 2023 and 2022.

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 APCo 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. APCo's derivative contracts with cross-acceleration provisions outstanding as of December 31, 2023 and 2022 were not material.

Cross-Default Triggers

In addition, a majority of APCo'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. APCo had derivative contracts with cross-default provisions in a net liability position of $22 million and no cash collateral posted as of December 31, 2023. APCo's derivative contracts with cross-default provisions outstanding as of December 31, 2022 were not material.

10. 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 Long-term Debt are summarized in the following table:

	December 31,			
	2023		2022	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
	$ 5,616.1	$ 5,390.1	$ 5,441.5	$ 5,079.2

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, APCo'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.

	December 31, 2023				
	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Special Deposits	$ 14.9	$ —	$ —	$ —	$ 14.9
Derivative Instrument Assets					
Risk Management Commodity Contracts (a)	—	1.1	23.5	(2.2)	22.4
Total Assets	$ 14.9	$ 1.1	$ 23.5	$ (2.2)	$ 37.3
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a)	$ —	$ 24.0	$ 1.1	$ (2.6)	$ 22.5

	December 31, 2022				
	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Special Deposits	$ 14.4	$ —	$ —	$ —	$ 14.4
Derivative Instrument Assets					
Risk Management Commodity Contracts (a)	—	0.7	69.4	(1.0)	69.1
Total Assets	$ 14.4	$ 0.7	$ 69.4	$ (1.0)	$ 83.5
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a)	$ —	$ 4.6	$ 0.3	$ (1.4)	$ 3.5

(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."

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	Derivative Instrument Assets (Liabilities)
	(in millions)
Balance as of December 31, 2022	$ 69.1
Realized Loss Included in Net Income (or Changes in Net Assets) (a) (b)	(11.7)
Settlements	(57.3)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	22.3
Balance as of December 31, 2023	$ 22.4

Year Ended December 31, 2022	Derivative Instrument Assets (Liabilities)
	(in millions)
Balance as of December 31, 2021	$ 41.7
Realized Gain Included in Net Income (or Changes in Net Assets) (a) (b)	3.0
Settlements	(44.7)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	69.1
Balance as of December 31, 2022	$ 69.1

(a) Included in revenues on the 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 the statements of income. These changes in fair value are recorded as regulatory liabilities for net gains and as regulatory assets for net losses or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

Significant Unobservable Inputs
December 31, 2023

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in millions)						
FTRs	$ 23.5	$ 1.1	Discounted Cash Flow	Forward Market Price	$ (1.04)	$ 6.45	$ 1.36

December 31, 2022

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in millions)						
FTRs	$ 69.4	$ 0.3	Discounted Cash Flow	Forward Market Price	$ (2.82)	$ 18.88	$ 3.89

(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 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)

11. INCOME TAXES

Income Tax Expense

The details of APCo's income taxes as reported are as follows:

	Years Ended December 31,	
	2023	2022
	(in millions)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ 74.6	$ (54.7)
Deferred	(9.0)	76.9
Total	65.6	22.2
Charged (Credited) to Non-Operating Income, Net:		
Current	(6.1)	(6.3)
Deferred	(45.3)	2.8
Total	(51.4)	(3.5)
Total Income Tax Expense	$ 14.2	$ 18.7

The following is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported:

	2023	2022
Net Income	$ 294.4	$ 394.2
Income Tax Expense	14.2	18.7
Pretax Income	$ 308.6	$ 412.9
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 64.8	$ 86.7
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Reversal of Origination Flow-Through	9.9	4.7
State and Local Income Taxes, Net	9.9	(5.5)
Removal Costs	(5.1)	(9.8)
AFUDC	(5.5)	(3.7)
Tax Reform Excess ADIT Reversal	(17.3)	(50.9)
Remeasurment of Excess of ADIT	(46.0)	—
Return to Provision Adjustment	3.4	(2.8)
Other	0.1	—
Income Tax Expense	$ 14.2	$ 18.7
Effective Income Tax Rate	4.6 %	4.5 %

Net Deferred Tax Liability

The following table shows elements of APCo's net deferred tax assets (liabilities) and significant temporary differences:

	December 31,	
	2023	2022
	(in millions)	
Deferred Tax Assets	$ 468.2	$ 504.2
Deferred Tax Liabilities	(2,484.6)	(2,501.1)
Net Deferred Tax Liabilities	$ (2,016.4)	$ (1,996.9)
Property Related Temporary Differences	$ (1,556.0)	$ (1,509.8)
Amounts Due to Customers for Future Income Taxes	143.4	163.0
Deferred State Income Taxes	(309.3)	(319.4)
Regulatory Assets	(257.4)	(301.2)
Securitized Assets	(29.2)	(33.9)
Operating Lease Liability	15.1	15.6
All Other, Net	(23.0)	(11.2)
Net Deferred Tax Liabilities	$ (2,016.4)	$ (1,996.9)

Federal and State Income Tax Audit Status

The statute of limitations for the IRS to examine APCo and other AEP subsidiaries originally filed federal return has expired for tax years 2016 and earlier. APCo 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. APCo and other AEP subsidiaries have received and agreed to immaterial IRS proposed adjustments on the 2017 tax return. The IRS exam is complete, and APCo 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.

APCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns, and APCo 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 Tax Legislation

Inflation Reduction Act

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, APCo 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, which provided initial CAMT guidance that APCo and other AEP subsidiaries can begin to rely on in 2023. 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 APCo and other AEP subsidiaries's potential CAMT exposure. In September 2023, the IRS released Notice 2023-64, which clarifies and supplements items in Notice 2023-7 and stated that additional guidance in the
form of proposed regulations is expected. APCo and other AEP subsidiaries will continue to monitor and assess any additional guidance.

APCo 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. APCo and other AEP subsidiaries will present the loss on sale of tax credits through income tax expense.

12. LEASES

APCo 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. APCo 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 APCo will exercise the option.

Lease obligations are measured using the discount rate implicit in the lease when that rate is readily determinable. AEP 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, APCo measures its lease obligation using its estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk-free rate and a secured credit spread relative to the lessee on a matched maturity basis.

Operating and Finance lease rental costs are generally charged to Operation Expense and Maintenance Expense 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. The components of rental costs were as follows:

	Years Ended December 31,	
	2023	2022
	(in millions)	
Operating Lease Cost	$ 18.5	$ 17.9
Finance Lease Cost:		
Amortization of Right-of-Use Assets	8.3	7.9
Interest on Lease Liabilities	1.8	2.0
Total Lease Rental Costs (a)	$ 28.6	$ 27.8

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

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

	December 31,	
	2023	2022
	(in millions)	
Weighted-Average Remaining Lease Term (years):		
Operating Leases	6.01	5.29
Finance Leases	4.16	4.25
Weighted-Average Discount Rate:		
Operating Leases	3.50 %	3.61 %
Finance Leases	7.04 %	7.09 %

	Years Ended December 31,	
	2023	2022
	(in millions)	
Cash paid for amounts included in the measurement of lease liabilities:		
Operating Cash Flows from Operating Leases	$ 18.3	$ 17.9
Operating Cash Flows from Finance Leases	10.1	9.9
Non-cash Acquisitions Under Operating Leases	$ 15.7	$ 23.1

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

	December 31,	
	2023	2022
	(in millions)	
Property, Plant and Equipment Under Finance Leases:		
Utility Plant (a)	$ 26.0	$ 29.3
Net Property, Plant and Equipment Under Finance Leases	$ 26.0	$ 29.3
Obligations Under Finance Leases:		
Noncurrent	$ 17.8	$ 21.6
Current	8.2	7.7
Total Obligations Under Finance Leases	$ 26.0	$ 29.3

(a) Includes $37 million and $32 million of accumulated provision for depreciation and amortization for the years ended December 31, 2023 and 2022, respectively.

	December 31,	
	2023	2022
	(in millions)	
Property, Plant and Equipment Under Operating Leases:		
Utility Plant (a)	$ 73.7	$ 73.6
Net Property, Plant and Equipment Under Operating Leases	$ 73.7	$ 73.6
Obligations Under Operating Leases:		
Noncurrent	$ 59.8	$ 59.1
Current	14.6	15.0
Total Obligations Under Operating Leases	$ 74.4	$ 74.1

(a) Includes $47 million and $49 million of accumulated provision for depreciation and amortization for the years ended December 31, 2023 and 2022, respectively.

Future minimum lease payments consisted of the following as of December 31, 2023:

	Finance Leases	Operating Leases
	(in millions)	
2024	$ 9.9	$ 17.8
2025	8.5	14.8
2026	3.5	13.3
2027	2.3	12.1
2028	1.9	10.0
After 2028	3.4	16.8
Total Future Minimum Lease Payments	29.5	84.8
Less: Imputed Interest	3.5	10.4
Estimated Present Value of Future Minimum Lease Payments	$ 26.0	$ 74.4

Master Lease Agreements

APCo 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, APCo 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 by APCo for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was $6 million.

Lessor Activity

APCo's lessor activity was immaterial as of and for the twelve months ended December 31, 2023 and December 31, 2022, respectively.

13. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding:

	Maturity	Weighted-Average Interest Rate as of December 31, 2023	Interest Rate Ranges as of December 31, 2023	Interest Rate Ranges as of December 31, 2022	Outstanding as of December 31, 2023	Outstanding as of December 31, 2022
					(in millions)	
Senior Unsecured Notes	2025-2050	4.68%	2.70%-7.00%	2.70%-7.00%	$ 4,625.0	$ 4,625.0
Pollution Control Bonds (a)	2024-2036 (b)	2.89%	0.63%-4.90%	0.63%-3.80%	431.0	431.0
Securitization Bonds	2028 (c)	3.77%	3.77%	2.01%-3.77%	147.7	174.2
Other Long-term Debt	2024-2026	6.53%	6.46%-13.72%	4.84%-13.72%	426.7	226.8
Unamortized Discount, Net					(14.3)	(15.5)
Total Long-term Debt Outstanding					$ 5,616.1	$ 5,441.5

(a) For certain series of Pollution Control Bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and insurance policies support certain series. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year - Nonaffiliated on the balance sheets.
(b) Certain Pollution Control Bonds are subject to redemption earlier than the maturity date.
(c) Dates represent the scheduled final payment dates for the securitization bonds. The legal maturity date is one to two years later. These bonds have been classified for maturity and repayment purposes based on the scheduled final payment date.

As of December 31, 2023, long-term debt was payable as follows:

	(in millions)	
2024	$	538.8
2025		673.3
2026		30.9
2027		355.6
2028		31.8
After 2028		4,000.0
Principal Amount		5,630.4
Unamortized Discount, Net		(14.3)
Total Long-term Debt	$	5,616.1

Long-term Debt Subsequent Events

In February 2024, APCo retired $13 million of Securitization Bonds.

Dividend Restrictions

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

All of the dividends declared by APCo 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. However, the Federal Power Act creates a reserve on retained earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to APCo.

APCo has credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The most restrictive dividend limitation for APCo is through the Federal Power Act restriction. As of December 31, 2023, the maximum amount of restricted net assets of APCo that may not be distributed to the Parent in the form of a loan, advance or dividend was $2.8 billion.
The Federal Power Act restriction limits the ability of APCo to pay dividends out of retained earnings because of their ownership in hydroelectric generation. As of December 31, 2023, the amount of any such restrictions was $722 million.

Corporate Borrowing Program

APCo uses a corporate borrowing program to meet its 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, 2023 and 2022 are included in Notes Payable to Associated Companies on the balance sheets. APCo's 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 millions)			
2023	$ 388.6	$ —	$ 283.5	$ —	$ 339.6	$ 750.0
2022	438.4	194.7	181.7	148.9	182.2	500.0

The 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 Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rates for Funds Borrowed from the Utility Money Pool	Average Interest Rates for Funds Loaned to the Utility Money Pool
2023	5.81 %	4.66 %	— %	— %	5.54 %	— %
2022	5.28 %	0.10 %	3.39 %	1.63 %	2.34 %	2.57 %

Interest expense and interest income related to the Utility Money Pool financing relationship are included in Interest on Debt to Associated Companies and Interest and Dividend Income, respectively, on the statements of income. The interest expense related to the corporate borrowing programs were $17 million and $6 million for the years ended December 31, 2023 and 2022, respectively, and interest income related to the corporate borrowing programs were $1 million and $3 million for the years ended December 31, 2023 and 2022, respectively.

Credit Facilities

See "Letters of Credit" section of Note 6 for additional information.

Securitized Accounts Receivables – AEP Credit

Under this sale of receivables arrangement, APCo sells, without recourse, certain of its customer accounts receivable and accrued utility revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for APCo's receivables. APCo does not have regulatory authority to sell its West Virginia accounts receivable. The costs of customer accounts receivable sold are reported in Other Deductions on APCo's statements of income. APCo manages and services its customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for APCo and retains the remainder.

The amount of accounts receivable and accrued utility revenues under the sale of receivables agreement as of December 31, 2023 and 2022 were $185 million and $194 million, respectively.

The fees paid to AEP Credit for customer accounts receivable sold were $17 million and $9 million for the years ended December 31, 2023 and 2022, respectively.
The proceeds on the sale of receivables to AEP Credit were $1.8 billion and $1.6 billion for the years ended December 31, 2023 and 2022, respectively.

14. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Income Taxes and Investment Tax Credits" section of Note 1 in addition to "Corporate Borrowing Program" and "Securitized Accounts Receivables – AEP Credit" sections of Note 13.

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.

Joint License Agreement

AEPTCo entered into a 50-year joint license agreement with APCo allowing either party to occupy the granting party's facilities or real property. In addition, AEPTCo entered into a 5-year joint license agreement with APCo and WPCo. After the expiration of these agreements, the term shall automatically renew for successive one-year terms unless either party provides notice. The joint license billing provides compensation to the granting party for the cost of carrying assets, including depreciation expense, property taxes, interest expense, return on equity and income taxes. APCo recorded income related to these agreements in Operating Revenues on the statements of income. The impact of the joint license agreement for the years ended December 31, 2023 and 2022 was not material.

Sales and Purchases of Property

APCo had affiliated sales and purchases of electric property 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 Utility Plant 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 2023, there were no charitable contributions made to the AEP Foundation. In 2022, APCo made a $13 million charitable contribution to the AEP Foundation recorded in Donations on the statements of income.

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. APCo recorded the costs paid to I&M of $39 million and $36 million for the years ended December 31, 2023 and 2022, respectively, as Operation Expenses.

Transmission Service Charges

The AEP East Companies are parties to the TA, which defines how transmission costs through the 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 AEP East Companies through the PJM OATT.
APCo recorded the net transmission service charges discussed above of $365 million and $345 million, for the years ended December 31, 2023 and 2022, respectively, in Operation Expense on the statements of income. Refer to the Affiliated Revenues section below for amounts related to these transactions.

Affiliated Revenues

The following table shows the revenues derived from direct sales to affiliates, auction sales to affiliates, net transmission agreement sales and other revenues for the years ended December 31, 2023 and 2022:

Related Party Revenues	Years Ended December 31, 2023		2022	
	(in millions)			
Direct Sales to East Affiliates	$	158.7	$	169.7
Transmission Revenues		70.9		77.5
Other Revenues		9.7		8.9
Total Affiliated Revenues	$	239.3	$	256.1

OVEC

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2023, the ownership and investment in OVEC were as follows:

Company	December 31, 2023 Ownership	Investment	
		(in millions)	
Parent	39.17 %	$	4.0
OPCo	4.30 %		0.4
Total	43.47 %	$	4.4

OVEC's owners, along with APCo and I&M, are members to an intercompany power agreement. Participants of this agreement are entitled to receive and are obligated to pay for all OVEC generating capacity, approximately 2,400 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries, including APCo, I&M and OPCo, is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, including outstanding indebtedness, and provide a return on capital. The intercompany power agreement ends in June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests. OVEC financed capital expenditures in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at its two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2023 and 2022, OVEC's outstanding indebtedness was approximately $1.1 billion and $1.1 billion, respectively. Although they are not an obligor or guarantor, AEP utility subsidiaries are responsible for their respective ratio of OVEC's outstanding debt through the intercompany power agreement. Principal and interest payments related to OVEC's outstanding indebtedness are disclosed in accordance with the accounting guidance for "Commitments." See the "Commitments" section of Note 6 for additional information.

Purchased Power from OVEC

APCo paid $122 million and $119 million for power purchased from OVEC for the years ended December 31, 2023 and 2022, respectively. The amounts shown above are recoverable from customers and are included in Operating Revenues and Operation Expenses on the statement of income.

15. PROPERTY, PLANT AND EQUIPMENT

Depreciation

APCo 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 by functional class:

Year	Other Production	Steam	Hydro	Transmission	Distribution	General
			(in percentages)			
2023	2.7	3.4	3.4	2.3	3.6	7.4
2022	2.7	3.7	3.7	2.2	3.6	7.3

The composite depreciation rate generally includes a component for 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

APCo recorded the following revisions to ARO estimates as of December 31, 2023 and 2022:

- In September 2022, APCo recorded a $14 million revision due to an increase in estimated ash pond closure costs at the Amos Plant.
- In 2023, APCo recorded revisions of $27 million primarily due to an increase in estimated asbestos costs at several plants.

The following is a reconciliation of the 2023 and 2022 aggregate carrying amounts of ARO:

Year	ARO at January 1,		Accretion Expense		Liabilities Incurred		Liabilities Settled		Revisions in Cash Flow Estimates (a)		ARO at December 31,	
						(in millions)						
2023	$	427.7	$	16.8	$	16.1	$	(23.1)	$	26.5	$	464.0 (b)(c)
2022		404.6		15.8		3.0		(12.7)		17.0		427.7 (b)(c)

(a) Unless discussed above, primarily related to ash ponds, landfills and mine reclamation, generally due to changes in estimated closure area, volumes and/or unit costs.
(b) Includes ARO related to ash disposal facilities.
(c) Includes ARO related to asbestos removal.

16. REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregated Revenues from Contracts with Customers

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

	Years Ended December 31, 2023		2022	
	(in millions)			
Retail Revenues:				
Residential Revenues	$	1,611.9	$	1,557.4
Commercial Revenues		699.1		642.8
Industrial Revenues (a)		777.9		663.4
Other Retail Revenues		106.2		87.1
Total Retail Revenues		3,195.1		2,950.7
Wholesale Revenues:				
Generation Revenues (b)		322.7		409.8
Transmission Revenues (c)		181.0		167.0
Total Wholesale Revenues		503.7		576.8
Other Revenues from Contracts with Customers (a)		73.6		99.1
Total Revenues from Contracts with Customers		3,772.4		3,626.6
Other Revenues:				
Alternative Revenue Programs (d)		(20.1)		(1.3)
Other Revenues		0.4		0.8
Total Other Revenues		(19.7)		(0.5)
Total Operating Revenues	$	3,752.7	$	3,626.1

(a) Amounts include affiliated and nonaffiliated revenues.
(b) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $159 million and $170 million as of December 31, 2023 and 2022, respectively, primarily relating to the PPA with KGPCo. The remaining affiliated amounts were immaterial.
(c) Amounts include affiliated and nonaffiliated revenues. The affiliated revenue for APCo was $93 million and $78 million as of December 31, 2023 and 2022, respectively. The remaining affiliated amounts were immaterial.

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

Performance Obligations

APCo 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. APCo 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 APCo are summarized as follows:

Retail Revenues

APCo 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 APCo 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

APCo 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.

APCo 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 and vary by state, where the revenues are reflected gross in the disaggregated revenues table above.

APCo has a performance obligation to supply wholesale electricity to KGPCo through a PPA. The FERC regulates the cost-based wholesale power transactions between APCo and KGPCo. The purchased power agreement includes a component for the recovery of transmission costs under the FERC OATT. The transmission cost component of purchased power is cost-based and regulated by the Tennessee Regulatory Authority. APCo's performance obligation under the purchased power agreement is satisfied over time as KGPCo simultaneously receives and consumes the wholesale electricity. APCo's revenues from the purchased power agreement are presented within the Generation Revenues line in the disaggregated revenues table above.

Wholesale Revenues - Transmission

APCo has performance obligations to transmit electricity to wholesale customers through assets owned and operated. 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.

APCo 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. Affiliate revenues as a result of the respective TA are reflected as Transmission Revenues in the disaggregated revenues table above.

Fixed Performance Obligations

The following table represents the 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. APCo 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. APCo amounts shown in the table below include affiliated and nonaffiliated revenues.

2024	2025-2026	2027-2028	After 2028	Total
		(in millions)		
$ 16.1	$ 32.2	$ 23.2	$ 11.7	$ 83.2

Contract Assets and Liabilities

Contract assets are recognized when APCo 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. APCo did not have any material contract assets as of December 31, 2023 and 2022.

When APCo 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 sheets 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. APCo's contract liabilities typically arise from services provided under joint use agreements for utility poles. APCo did not have any material contract liabilities as of December 31, 2023 and 2022.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on APCo's balance sheets within the Customer Accounts Receivable line item. APCo'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, 2023 and 2022. See "Securitized Accounts Receivable - AEP Credit" section of Note 13 for additional information.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable from Associated Companies on APCo's balance sheets were $72 million and $65 million, as of December 31, 2023 and 2022.

Contract Costs

Contract costs to obtain or fulfill a contract for APCo are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and are neither bifurcated nor reclassified between current assets and deferred debits on the 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 the income statements. APCo did not have material contract costs as of December 31, 2023 and 2022.

17. <u>FERC ORDER NO. 784-A</u>

On July 18, 2013, the FERC issued Order No. 784 that revised certain aspects of the accounting and reporting requirements under the Uniform System of Accounts related to energy storage accounts. Due to software limitations, the newly adopted and revised schedules in the FERC forms that would contain the energy storage accounts are not available to filers of the forms for use as of the effective date. Utilities with energy storage assets must use the existing schedules in the FERC Forms to report energy storage assets pending availability of the new and revised schedules. FERC directed filers to submit the requested energy storage information as part of pages 122-123.

The following table presents APCo's energy storage operations for small plants for the years ended December 31, 2023 and 2022, as required by FERC Order No. 784:

Project Name	Functional Classification	Project Location	Project Costs		Operation Expenses		Maintenance Expenses	
			Account	Amount	Account	Amount	Account	Amount
					(dollars in millions)			
<u>Year Ended December 31, 2023</u>								
Balls Gap Station	Distribution	Balls Gap, WV	363	$ 0.2	562	$ —	592	$ —
Byllesby Hydro Plant	Generation	Ivanhoe, Virginia	348	5.7	562	—	592	—
Chemical Station	Transmission	N. Charleston, WV	351	—	562	—	592	—
<u>Year Ended December 31, 2022</u>								
Balls Gap Station	Distribution	Balls Gap, WV	363	$ 0.2	562	$ —	592	$ —
Byllesby Hydro Plant	Generation	Ivanhoe, Virginia	348	5.7	562	—	592	—
Chemical Station	Transmission	N. Charleston, WV	351	—	562	—	592	—

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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			(64,260)	16,939,564	7,503,894		24,379,198		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				(1,881,834)	(834,896)		(2,716,730)		
3	Preceding Quarter/Year to Date Changes in Fair Value			(36)	(26,517,723)			(26,517,759)		
4	Total (lines 2 and 3)			(36)	(28,399,557)	(834,896)		(29,234,489)	394,160,953	364,926,464
5	Balance of Account 219 at End of Preceding Quarter/Year			(64,296)	(11,459,993)	6,668,998		(4,855,291)		
6	Balance of Account 219 at Beginning of Current Year			(64,296)	(11,459,993)	6,668,998		(4,855,291)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				(2,461,567)	(834,896)		(3,296,463)		
8	Current Quarter/Year to Date Changes in Fair Value			299	4,304,602			4,304,901		
9	Total (lines 7 and 8)			299	1,843,035	(834,896)		1,008,438	294,423,705	295,432,143
10	Balance of Account 219 at End of Current Quarter/Year			(63,997)	(9,616,958)	5,834,102		(3,846,853)		

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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)	16,264,902,888	16,264,902,888					
4	Property Under Capital Leases	99,738,368.00	99,738,368.00					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	1,554,539,564	1,554,539,564					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	17,919,180,820	17,919,180,820					
9	Leased to Others							
10	Held for Future Use	3,374,772.00	3,374,772.00					
11	Construction Work in Progress	718,224,524	718,224,524					
12	Acquisition Adjustments	181,679.00	181,679.00					
13	Total Utility Plant (8 thru 12)	18,640,961,795	18,640,961,795					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	6,446,565,009	6,446,565,009					
15	Net Utility Plant (13 less 14)	12,194,396,786	12,194,396,786					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	6,278,780,471	6,278,780,471					
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	167,604,260	167,604,260					
22	Total in Service (18 thru 21)	6,446,384,731	6,446,384,731					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation	(1,401.00)	(1,401.00)					
29	Amortization							
30	Total Held for Future Use (28 & 29)	(1,401)	(1,401)					
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	181,679.00	181,679.00					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,446,565,009	6,446,565,009					

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Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	133,394					133,394
3	(302) Franchise and Consents	15,265,288	2,044				15,267,332
4	(303) Miscellaneous Intangible Plant	283,258,498	43,770,088	35,902,430			291,126,156
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	298,657,180	43,772,132	35,902,430			306,526,882
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	12,363,468					12,363,468
9	(311) Structures and Improvements	433,177,002	151,894,132	14,254,833			570,816,301
10	(312) Boiler Plant Equipment	4,443,814,840	76,272,953	29,549,657			4,490,538,136
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	461,452,848	5,388,117	3,961,935			462,879,030
13	(315) Accessory Electric Equipment	183,975,696	1,166,419	499,840			184,642,275
14	(316) Misc. Power Plant Equipment	91,618,720	20,163,325	3,134,331			108,647,714
15	(317) Asset Retirement Costs for Steam Production	113,916,326	30,907,518				144,823,844
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	5,740,318,900	285,792,464	51,400,596			5,974,710,768
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	9,800,813					9,800,813
28	(331) Structures and Improvements	33,386,322	2,685,407	233,902			35,837,827
29	(332) Reservoirs, Dams, and Waterways	87,037,721	4,811,671	955,469			90,893,923
30	(333) Water Wheels, Turbines, and Generators	121,736,180	4,539,319	537,353			125,738,146
31	(334) Accessory Electric Equipment	26,970,334	1,069,477	207,367			27,832,444
32	(335) Misc. Power Plant Equipment	24,399,805	3,491,336	86,222			27,804,919
33	(336) Roads, Railroads, and Bridges	1,241,854					1,241,854
34	(337) Asset Retirement Costs for Hydraulic Production	2,682,604					2,682,604
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	307,255,633	16,597,210	2,020,313			321,832,530
36	D. Other Production Plant						
37	(340) Land and Land Rights	3,196,932					3,196,932
38	(341) Structures and Improvements	51,981,238	2,383,807	905,062			53,459,983
39	(342) Fuel Holders, Products, and Accessories	27,022,746					27,022,746

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	518,125,283	14,934,240	2,093,378			530,966,145
42	(345) Accessory Electric Equipment	48,255,755	888,011	209,990			48,933,776
43	(346) Misc. Power Plant Equipment	33,430,019	1,401,492	865,407			33,966,104
44	(347) Asset Retirement Costs for Other Production		68,653				68,653
44.1	(348) Energy Storage Equipment - Production	5,726,249					5,726,249
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	687,738,222	19,676,203	4,073,837			703,340,588
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	6,735,312,755	322,065,877	57,494,746			6,999,883,886
47	3. Transmission Plant						
48	(350) Land and Land Rights	217,229,589	15,258,680	1		(491)	232,487,777
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	178,591,348	16,456,686	620,744			[a]194,427,290
50	(353) Station Equipment	2,079,782,648	103,923,362	8,061,574		(2,545,268)	2,173,099,168
51	(354) Towers and Fixtures	517,390,378	545,964	766,948			517,169,394
52	(355) Poles and Fixtures	574,384,094	83,688,133	12,335,684			645,736,543
53	(356) Overhead Conductors and Devices	865,848,378	33,383,392	2,486,536			896,745,234
54	(357) Underground Conduit	19,190,127	2,553,295				21,743,422
55	(358) Underground Conductors and Devices	28,792,658	486,551	487,697			28,791,512
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)	4,481,209,220	256,296,063	24,759,184		(2,545,759)	4,710,200,340
59	4. Distribution Plant						
60	(360) Land and Land Rights	75,558,004	840,826	82,456		327,042	76,643,416
61	(361) Structures and Improvements	78,092,463	7,632,692	608,134			85,117,021
62	(362) Station Equipment	741,589,543	36,249,484	13,884,310		2,545,268	766,499,985
63	(363) Energy Storage Equipment – Distribution	165,101					165,101
64	(364) Poles, Towers, and Fixtures	925,510,430	75,800,934	9,362,907			991,948,457
65	(365) Overhead Conductors and Devices	1,244,374,864	87,786,176	10,295,042			1,321,865,998
66	(366) Underground Conduit	150,196,348	5,651,692	76,411			155,771,629
67	(367) Underground Conductors and Devices	334,789,032	14,056,151	587,784			348,257,399
68	(368) Line Transformers	669,288,471	46,449,607	9,739,233			705,998,845
69	(369) Services	388,682,017	18,166,908	2,436,115			404,412,810
70	(370) Meters	220,376,605	12,725,200	21,768,743			211,333,062
71	(371) Installations on Customer Premises	66,564,002	8,488,549	3,716,963			71,335,588
72	(372) Leased Property on Customer Premises	771					771
73	(373) Street Lighting and Signal Systems	33,676,795	2,756,552	598,360			35,834,987
74	(374) Asset Retirement Costs for Distribution Plant	2,971,365		2,968,296			3,069
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,931,835,811	316,604,771	76,124,754		2,872,310	5,175,188,138
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	17,322,505	4,310,804	814,196		(2,802,974)	18,016,139
87	(390) Structures and Improvements	252,402,854	44,085,810	2,902,655		2,803,465	296,389,474
88	(391) Office Furniture and Equipment	14,402,600	2,558,694	120,495			16,840,799
89	(392) Transportation Equipment	8,674					8,674
90	(393) Stores Equipment	2,236,970	1,443,887				3,680,857
91	(394) Tools, Shop and Garage Equipment	46,477,079	5,715,855				52,192,934
92	(395) Laboratory Equipment	2,707,424		373,072			2,334,352

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	114,334					114,334
94	(397) Communication Equipment	187,394,480	38,660,052	1,093,096			224,961,436
95	(398) Miscellaneous Equipment	10,583,741	1,272,698	182,172			11,674,267
96	SUBTOTAL (Enter Total of lines 86 thru 95)	533,650,661	98,047,800	5,485,686		491	626,213,266
97	(399) Other Tangible Property	43,287					43,287
98	(399.1) Asset Retirement Costs for General Plant	1,366,095	36,219	15,661			1,386,653
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	535,060,043	98,084,019	5,501,347		491	627,643,206
100	TOTAL (Accounts 101 and 106)	16,982,075,009	1,036,822,862	199,782,461		327,042	17,819,442,452
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)	16,982,075,009	1,036,822,862	199,782,461		327,042	17,819,442,452
	Page 204-207						

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FOOTNOTE DATA

(a) Concept: StructuresAndImprovementsTransmissionPlant
The investment and related accumulated depreciation in Generation Step-Up Units (GSUs) in plant accounts 352-353 included in APCo's generation formula rates are identified by a query of the plant accounting system

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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						
3						
4						
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46						
47	TOTAL					

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ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Amos-Gavin 765KV Comm Solvents Tract Land, WV (2639)	09/23/1974		256,070
3	John E. Amos Fly Ash Area 3, Putnam Co., WV - approx 132.65 acres of land (0745)	06/30/1973		287,901
4	Shadwell 69KV Substation, Roanoke County, VA 10.637 acres (7662)	08/01/2009	12/31/2024	431,124
5	Fries 69KV Substation, Grayson Co., VA - 21.61 acres (6101)	08/01/2023	12/31/2024	557,123
6	Items under $250,000			1,842,554.00
21	Other Property:			
22				
23				
24				
25				
26				
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28				
29				
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44				
45				
46				
47	TOTAL			3,374,772

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	204MW APCo Wind 2025 (Top Hat)	5,134,115
2	ADMS Imp DSN DNEX-APC D	10,001,225
3	AM CCR/ELG Compliance	35,941,994
4	AM FGD Landfill Sequence 4-10	7,770,724
5	AM U3 Sidewall Replacement	4,377,639
6	AM2 SCR CAT L1 REPLACE	2,882,444
7	Amos Simulator Upgrade	1,363,320
8	Amos U0 Urea Direct Injection	3,187,039
9	Amos U1 Phase 3 GSU Replace	5,287,815
10	Amos U3 DCS Controls Upgrade	3,613,478
11	Amos U3 Duct Repair Project	7,066,873
12	Amos Unit 3 DSI Project	2,014,608
13	AMU3 Replace SCR Catalyst L3	4,069,562
14	APCO - Transmission Work	3,001,242
15	APCo AMI Project VA	3,667,046
16	APCO AMI Project WV	8,301,368
17	APCo D (Floyd-Stuart Area)	2,104,105
18	APCO D Supplemental Work	1,205,168
19	APCO D Work	1,698,235
20	APCo D Work (Supplemental)	18,862,913
21	APCO Distr Pre Eng Parent	8,760,831
22	APCO Distribution Line Work	1,120,329
23	APCO Distribution Work	8,343,540
24	APCO HCP	1,198,068
25	APCo Major Eq/ Spares-Distr	1,205,496
26	APCO T (Baseline)	9,233,631
27	APCo T (Floyd-Stuart Area)	3,070,510
28	APCo T CI	2,960,140
29	APCO T Supplemental Work	5,057,697
30	APCo T Work 1	5,847,175
31	APCo T Work 2	3,413,126
32	APCo T Work 3	2,474,101
33	APCo T Work 4	1,869,616
34	APCo T Work 5	1,515,997
35	APCo T Work 6	1,576,290
36	APCo T Work 7	5,396,367
37	APCo T Work 8	1,004,436
38	APCo T Work 9	7,221,255
39	APCo T Work 10	6,025,341
40	APCo T Work (Supplemental)	36,613,080
41	APCo T-BlnktProj Under $3M	18,341,375
42	APCO Trans Pre Eng Parent	10,779,270
43	APCO Transmission Work	12,624,385
44	APCo VA Major Eq/ Spares-Trans	2,652,519
45	APCo VA Major Eq/Spares- Distr	3,397,564
46	APCo WV Major Eq/Spares-Trans	3,562,534
47	APCO: 2020 - 2022 RBB Grayson	4,153,920

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
48	APCO: 2021 - 2023 RBB LOGAN &	30,160,537
49	APCO-D	5,386,572
50	APCo-D BlnktProj Under $3M	1,844,382
51	APCo-D Service Restoration Blk	1,254,818
52	APCo-D Small Cap Adds Blkt	1,112,038
53	APCO-D Telecom	4,487,363
54	APCo-D Third Party Work Blkt	(4,847,431)
55	APCO-G Telecom	1,327,305
56	APCO-T	4,884,063
57	APCo-T TTMP 2024 CI	1,897,294
58	APCO-T Virginia Baseline CI	2,017,065
59	APCO-T Virginia CI	6,184,075
60	APCO-T Work	2,188,400
61	Bluefield TTMP 2023 APCo-T CI	5,163,225
62	Ceredo CT1 HGP Capital 1	2,701,528
63	Ceredo CT1 HGP Capital 2	2,872,575
64	CIS-Common Deployment-APC D	8,716,006
65	CLH 3 Tailrace Disolved Oxygen	1,947,592
66	CLH 4 Tailrace Disolved Oxygen	6,845,915
67	CoCo - Install Dist Bank	1,437,381
68	Corp Prgrm Billing - APCO Tran	5,498,664
69	D/AP/Capital Blanket - APCo	2,580,126
70	D/AP/Distribution Work	6,130,623
71	Distribution Underground	1,552,992
72	Ds AP WVirg-Anda	1,026,112
73	ED CI APCO T Asset IMP	1,373,634
74	Ed-Ci-Apco-D Ast Imp	33,468,026
75	Ed-Ci-Apco-D Cust Serv	5,110,119
76	EV Chargers for GL BU 140	1,812,919
77	Hockman 138kV Extension	1,270,777
78	Hockman Sta - Sta Work	7,702,380
79	J.Early-Indep APCo D Work	1,002,630
80	John Vaughan Adjacent Land Pur	2,154,694
81	Kenna- New Station(APCO)	7,208,213
82	MAH U0 Sheet Pile Project	1,174,398
83	Mount Heron - CoalCreek APCO-T	5,787,606
84	NIH RELICENSE NIAGARA HYDRO	2,061,676
85	Patrick Henry Sta - New Sta	1,916,189
86	Point Pleasant SC (New)	3,508,777
87	RCA Station - APCO Station	5,530,373
88	RCA T-Line Extension	10,179,534
89	Roanoke Transmission RDC	10,261,470
90	Roanoke TTMP2023 APCo-D CI	1,109,671
91	Roanoke TTMP2023 APCo-T CI	6,324,364
92	Sisson-Sta. Equip APCO	1,204,283
93	Smith Mountain Lake Offic/Crew	3,993,298
94	SS-CI-APCo-D GEN PLT 1	40,978,379
95	SS-CI-APCo-T GEN PLT 2	1,543,611
96	SSH Outlet Bank Replacement	6,897,310
97	T/AP/Capital Blanket - APCo	4,673,674
98	T/AP/NERC Physical Security	16,655,836
99	T/AP/Sheridan Trans CI	1,521,096
100	T/AP/Stuart Area Telecom Moder	1,247,602
101	Teays Valley SC Land Purchase	1,255,722
102	Wildwood - New Station	2,216,116

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
103	Winston Ave - New Station	3,227,245
104	Wo 020749999	9,003,988
105	WS-CI-APCo-G PPB	57,945,326
106	Other Minor Projects under $1,000,000	51,564,862
43	Total	718,224,524
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ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

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

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	5,964,387,881	5,964,392,029	(4,148)	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	525,147,399	525,144,652	2,747	
4	(403.1) Depreciation Expense for Asset Retirement Costs	5,622,576	5,622,576		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts	780,593	780,593		
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	(350,671)	[a](350,671)		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	531,199,897	531,197,150	2,747	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(163,389,212)	(163,389,212)		
13	Cost of Removal	(74,625,714)	[b](74,625,714)		
14	Salvage (Credit)	13,512,503	[c]13,512,503		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(224,502,423)	(224,502,423)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	7,693,715	7,693,715		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	6,278,779,070	6,278,780,471	(1,401)	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,981,030,122	2,981,030,122		
21	Nuclear Production				
22	Hydraulic Production-Conventional	78,907,954	78,907,954		
23	Hydraulic Production-Pumped Storage	101,433,633	101,433,633		
24	Other Production	278,145,454	278,145,454		
25	Transmission	911,749,615	911,753,763	(4,148)	
26	Distribution	1,806,088,635	1,806,085,888	2,747	
27	Regional Transmission and Market Operation				
28	General	121,423,657	121,423,657		
29	TOTAL (Enter Total of lines 20 thru 28)	6,278,779,070	6,278,780,471	(1,401)	

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FOOTNOTE DATA

(a) Concept: OtherAccounts

FERC Generation Wholesale Amortization-Clinch River ARO	$(32,124)
KGPCo Wholesale Amortiation-Clinch River ARO	$(50,700)
Generation Wholesale Expense-1823377 VA Plants	$(103,875)
KGPCo Wholesale Expense-1823377 VA Plants	$(163,972)
	$(350,671)

(b) Concept: CostOfRemovalOfPlant

Includes $18,213,469 of removal cost in retirement work in progress (RWIP).

(c) Concept: SalvageValueOfRetiredPlant

Includes ($7,133,621) of salvage in retirement work in progress (RWIP).

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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	Central Appalachian Coal Company							
2	SEC File 70-1841, 6-18-48							
3	SEC File 70-2749, 8.14-50							
4	3,000 shares common stock			3,000			3,000	
5	Capital Contributions Central Appalachian Coal Company	10/09/1990		449,990			449,990	
6	Undistributed earnings/losses and dividends - Central Appalachian Coal			194,057			194,057	
7	Central Coal Company							
8	SEC File 70-1770, 4-30-48							
9	1,500 shares common stock			1,500			1,500	
10	Capital Contributions Central Coal Company			602,368			602,368	
11	Investment in Central Coal Company							
12	Southern Appalachian Coal Company							
13	SEC File 70-5144, 3-23-72							
14	6,950 shares common stock			6,950			6,950	
15	Capital Contributions - Southern Appalachian Coal Company							
16	Investment in Premium on Common Stock			900,000			900,000	
17	Provision for Parent Savings Tax			9,015			(69,007)	
18	Undistributed earnings/losses and dividends - Southern Appalachian Coal Company			690,462			690,462	
19	Cedar Coal Company							
20	SEC File 70-5470, 4-30-74							
21	2,000 shares common stock	04/10/1974		200,000			200,000	
22	Capital Contributions - Cedar Coal			4,868,403			4,868,403	
23	Investment in Subsidiary AOCI			1,635,727		426,646	2,062,373	
24	Undistributed earnings/losses and dividends - Cedar Coal Company			(2,483,074)			(2,483,074)	
42	Total Cost of Account 123.1 $		Total	7,078,398		426,646	7,427,022	

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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)	151,723,238	303,375,126	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	7,213,740	11,642,310	Electric
3	Residuals and Extracted Products (Account 153)			Electric
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	53,145,634	111,552,626	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	74,201,072	31,712,112	Electric
8	Transmission Plant (Estimated)	220,506	2,038,896	Electric
9	Distribution Plant (Estimated)	1,902,286	2,227,248	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	[(a)]682,511	[(b)]583,760	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	130,152,009	148,114,642	
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	289,088,987	463,132,078	

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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 No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	1,154,058	21,928,937	185,897		161,871		161,726		4,208,874		5,872,426	21,928,937
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	6,358								162,274		168,632	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9	Restricted Title IV SO2 Allowances												
10	Other-see footnote		(13,073,141)										(13,073,141)
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	14,310	135,071									14,310	135,071
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Consent Decree Surrenders	(1,846)		145,982								144,136	
23													
24													
25													
26													
27													
28	Total	(1,846)		145,982								144,136	
29	Balance-End of Year	1,147,979	[(a)]8,720,725	39,915		161,871		161,726		4,371,148		5,882,639	8,720,725
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains		113										113
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	1,746		1,746		1,746		1,746		95,375		102,359	
37	Add: Withheld by EPA									3,491		3,491	
38	Deduct: Returned by EPA												
39	Cost of Sales	1,746								1,745		3,491	

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			1,746		1,746		1,746		97,121		102,359	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												
Page 228(ab)-229(ab)a													

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AllowanceInventory

NOX has no book value associated with the quantity. Amounts reflected on this page are for allowances related to CO_2.

Schedule Page: 229 Line No.: 10 Column: c

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	182,089	1,416,781	17,126								199,215	1,416,781
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	9,574		4,181								13,755	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9	Dogwood Power Management LLC	50,000	721,950									50,000	721,950
10	Other												
11													
12													
13													
14													
15	Total	50,000	721,950									50,000	721,950
16													
17	Relinquished During Year:												
18	Charges to Account 509	78,557	743,682									78,557	743,682
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Wolverine Power Supply Cooperative, Inc.												
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	163,106	[a]1,395,049	21,307								184,413	1,395,049
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												

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													

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AllowanceInventory

NOX has no book value associated with the quantity. Amounts reflected on this page are for allowances related to CO_2.

Schedule Page: 229 Line No.: 10 Column: c

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	[(a)] Glen Lyn Unit 6	5,703,621	(149,735)			4,444,676
2	[(b)] Kanawha Plant	27,432,795	964,031			18,487,838
3	[(c)] Sporn Plant	10,478,046	458,519			6,862,551
4	[(d)] Clinch River Plant Coal Assets	58,709,555	2,275,172			42,224,583
20	TOTAL	102,324,017	3,547,987			72,019,648

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfExtraordinaryPropertyLoss
Authorized by the West Virginia commission on May 26, 2015. Amortization period: June 2015 to July 2032.
(b) Concept: DescriptionOfExtraordinaryPropertyLoss
Authorized by the West Virginia commission on May 26, 2015. Amortization period: June 2015 to July 2041.
(c) Concept: DescriptionOfExtraordinaryPropertyLoss
Authorized by the West Virginia commission on May 26, 2015. Amortization period: June 2015 to February 2040.
(d) Concept: DescriptionOfExtraordinaryPropertyLoss
Clinch River Units 1 & 2 were authorized by the West Virginia commission on May 26, 2015. Amortization period: October 2015 to November 2052. Coal Blending Assets amortized through June 2048. Clinch River Unit 3 was authorized by the West Virginia commission on May 26, 2015. Amortization period: June 2015 to January 2040. The amortization period for all Clinch River units was updated to end in December 2040 by the West Virginia commission on February 27, 2019.

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

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

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	AC2-123	46	186	46	186
3	AD1-152	1,486	186	1,226	186
4	AE1-064	62,114	186	62,462	186
5	AE1-108	16,869	186	4,353	186
6	AE1-250	16,125	186	17,199	186
7	AE2-160	298	186	298	186
8	AE2-185	51,052	186	51,129	186
9	AE2-187	60,652	186	60,082	186
10	AE2-292	5,639	186	5,949	186
11	AF1-049	7,330	186	7,735	186
12	AF1-323	12,032	186	12,791	186
13	AF2-382	30,448	186	30,857	186
14	AG1-022	717	186	741	186
15	AG1-089	575	186	800	186
16	AG1-091	42,456	186	42,503	186
17	AG1-123	341	186	231	186
18	AG1-124	1,022	186	1,796	186
19	AG1-136	21,273	186	19,359	186
20	AG1-162	4,492	186	9,569	186
21	AG1-194	7,962	186	9,794	186
22	AG1-219	1,933	186	3,047	186
23	AG1-311	8,483	186	8,419	186
24	AG1-508	3,346	186	3,990	186
25	AG1-509	(231)	186		
26	AG1-528	13,109	186	19,771	186
27	AG2-311	52	186	61	186
28	AJ1-010	145	186	145	186
29	PJM - #AD1-102	3,757	186	6,688	186
30	PJM - #AD2-022	566	186		
31	PJM - #AD2-178	430	186	447	186
32	PJM - #AD2-179	4,274	186	1,865	186
33	PJM - #AE1-212	563	186		
34	PJM - #AE2-047	3,738	186	4,474	186
35	PJM - #AE2-140	366	186	366	186
36	PJM - #AE2-166	1,818	186		
37	PJM - #AE2-280	183	186	3,193	186
38	PJM - #AE2-326	4,182	186	4,319	186
20	Total	389,643		395,705	
21	**Generation Studies**				
22	PJM Niagra Hydro study	16,000	186		
39	Total	16,000			
40	Grand Total	405,643		395,705	

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Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	2021 PJM Transmission True-up, Amortization Period: 01/2023 - 12/2023	2,395,234	286,632	447, 456	2,681,867	(1)
2	2022 PJM Transmission True-up, Amortization Period: 01/2024 - 12/2024	324,932	1,601,942	447, 456	324,932	1,601,942
3	Capital Environmental Equity Costs, Rate Orders: VA Code Section 56-582B (vi) VA SCC PUE-2005-00056, Amortization Period: 01/2021 - 12/2023	(4,006)	4,006			
4	Carrying Chgs-Capital Environmental Compliance Costs, Rate Orders: VA Code Section 56-582B (vi) VA SCC PUE-2005-00056, Amortization Period: 01/2021 - 12/2023	(33,624)	33,624			
5	Carrying Chgs-COVID-19 Costs, VA SCC Case No. PUR-2020-00074	1,040,603	362,497	431	399,722	1,003,378
6	COVID-19 Costs - WV, General Order: WVPSC 262.4 - VA SCC Case No. PUR-2020-00074	7,078,132		182, 431	233,080	6,845,052
7	Defd Carrying Charges - Reliability Capital, Rate Orders: VA Code Section 56-582B (vi) VA SCC PUE-2005-00056, Amortization Period: 01/2021 - 12/2023	(19,734)	19,734			
8	Defd System Reliability Costs, Rate Orders: VA Code Section 56-582B (vi) VA SCC PUE-2005-00056, Amortization Period: 01/2021 - 12/2023	44,943		182, 407	44,943	
9	Demand Side Management Under Recovery, Rate Order: WV Public Service Commission - Case No: 10-0261-E-GI - Case No: WV PSC Case 15-0301-E-GI	9,992,088	3,001,055	182, 908	1,953,109	11,040,034
10	Dresden Operating Costs - VA, Rate Order: VA SCC PUE-2011-00036	7,979,749	4,318,092	403	1,387,947	10,909,894
11	Environmental Compliance Costs, Rate Orders: VA Code Section 56-582B (vi) VASCCPUE-2005-00056, Amortization Period: 01/2021 - 12/2023	65,594		182, 407	65,594	
12	Equity Carrying Chgs-COVID-19 Costs, VA SCC Case No. PUR-2020-00074	(473,135)	173,748	182, 431	156,837	(456,224)
13	Equity Costs - Capital Reliability, Rate Orders: VA Code Section 56-582B (vi) VA SCC PUE-2005-00056, Amortization Period: 01/2021 - 12/2023	(4,349)	4,349			
14	Glen Lyn Ash Pond ARO, VA HB443	299,901,647	10,627,338			310,528,985
15	M&S Retiring Plants, Rate Order: VA SCC PUE-2014-0026 - Rate Order: WV PSC 14-1151-E-D	363,132		506	36,324	326,808
16	NBV ARO's Retired Plants, Rate Order: VA SCC PUE-2014-0026 - Rate Order: WV PSC 14-1151-E-D	29,057,644	11,289,975	403	350,671	39,996,948
17	SFAS 106 Medicare Subsidy, Amortization period - 01/2013 to 12/2024	1,177,636		926	588,818	588,818
18	SFAS 109 Deferred FIT	114,495,896	460,344,729	182, 190, 236, 254, 255, 281, 282, 283, 409, 410, 411	460,415,821	114,424,804
19	SFAS 109 Deferred SIT	260,889,035	201,490,246	283	211,093,858	251,285,423
20	SFAS 112 Postemployment Benefits, Rate Order: WV PSC Case 14-1152-E-42T	13,743,319	1,954,040	228	797,989	14,899,370
21	SFAS 158 Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans	108,268,591	121,317,651	129, 228	113,790,365	115,795,877
22	Unrealized Loss on Forward Commitments		26,733,429	175, 244, 254, 456	4,871,259	21,862,170
23	Unrecovered Fuel - Common Wealth Virginia - Per Agreement with Commonwealth of Virginia. Effective June 4, 2015.	3,876,505	386,350	501	3,502,212	760,643
24	Unrecovered Fuel Cost - VA	180,705,933	250,260,182	182, 501	284,331,728	146,634,387
25	Unrecovered Fuel Cost - VA - Long-term	223,288,030	107,012,114	182	223,288,030	107,012,114
26	Unrecovered Fuel Cost - WV	288,492,066	252,267,682	501	532,796,281	7,963,467
27	VA 2017-2019 Triennial Under Earnings, Amortization Period: 10/2022 - 01/2024	30,092,576		407	27,777,756	2,314,820
28	VA A.5 PCAP-RAC Under Recovery	922,146	2,910,208	555	3,832,354	
29	VA Broadband Under Recovery	15,755,611	19,725,661	557	27,487,272	7,994,000

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
30	VA Demand Response Program, Rate Order: VA SCC PUE-2011-0001	2,589,847	830,953	442, 908	2,268,283	1,152,517
31	VA Distribution Substation Carrying Charge Deferral, Amortization Period: 08/2022 - 07/2023	731,048		182, 431	731,047	
32	VA Distribution Substation Depreciation Deferral, Amortization Period: 08/2022 - 07/2023	212,178		403	212,178	
33	VA Distribution Substation Equity Carrying Charge Deferral, Amortization Period: 08/2022 - 07/2023	(408,390)	408,390			
34	VA E-RAC Deferral AFUDC, Amortization Period: 12/2022 - 11/2023	2,725,779		501	2,725,779	
35	VA E-RAC Under Recovery		1,207,411	501	1,207,411	
36	VA Major Storm Expense, VA SCC Case No. PUR-2020-00015	37,867,310	53,268,506	593	46,180,839	44,954,977
37	VA PIPP Admin Cost Deferral	592,580		908	592,580	
38	VA RGGI Deferral	544,533		509	544,533	
39	VA T-RAC Costs, VA SCC Case No. PUE-2009-00031	18,139,772	33,608,448	566	26,247,956	25,500,264
40	WV ACNR Breach Cost Deferral	34,975	11,631	923	46,606	
41	WV Air Quality Permit Fees, Rate Order: WV 15-0722-E-P	143,990		506	123,420	20,570
42	WV Beneficial Electrification Program, Case No. 19-0396-E-PC	317,724	707,355	182, 908	208,502	816,577
43	WV CRR Under Recovery, Case No. 12-1188-E-PC	3,020,431	1,796,849	407	1,705,314	3,111,966
44	VA Deferred Rate Case Expenses, VA SCC Case No. PUR-2023-00002, Amortization Period: 01/2024 - 12/2024		762,669	182	216,182	546,487
45	WV Deferred Storm Expense	72,590,133	20,005,721	593	1,052,444	91,543,410
46	WV ECS Under Recovery	1,063,270	5,558,825			6,622,095
47	WV EE/DR - Company Funded, Case No. PUE-2014-00039	2,903,317	156,936	182, 908	1,098,552	1,961,701
48	WV MRBC Surcharge Under Recovery	866,453	3,182,733	403	1,943,105	2,106,081
49	WV Vegetation Management Program Costs, Rate Order: WV PSC Case 13-0557-E-P - Rate Order: WV PSC Case 14-1152-E-42T	13,686,390	13,863,714	593	14,619,847	12,930,257
50	WV Business Ready Site Program AFUDC Deferral		55,625			55,625
51	2023 PJM Transmission True-up, Amortization Period: 01/2025 - 12/2025		2,312,425	447	18,507	2,293,918
52	Unrecovered Fuel Cost - WV - Long-term		169,333,269	501	15,092,800	154,240,469
53	SO2 Allowance Inv - Recovery, VA SCC Case No. PUR-2023-00002, Amortization Period: 01/2023 - 12/2032		13,073,141	407	1,307,314	11,765,827
54	Deferred Carrying Charge-GlenLyn		1,097,672			1,097,672
55	Deferred Equity Carrying Charge-GlenLyn			407	476,984	(476,984)
44	TOTAL	1,757,037,534	1,797,367,557		2,020,828,952	1,533,576,138

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Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Credits Account Charged (d)	CREDITS Credits Amount (e)	Balance at End of Year (f)
1	Property Taxes West Virginia	75,015,609	94,509,917	107,236,408	88,176,284	81,349,242
2	Property Taxes Ohio	6,042,154	5,815,167	107,236,408	6,146,321	5,711,000
3	Agency Fees - Factored A/R	3,887,613	37,483,898	184,426	37,678,884	3,692,627
4	Labor Accruals - Balance Sheet	3,791	1,055,528	253/183/152/142/143	1,058,919	400
5	Miscellaneous	178,139	174,798	[(a)] 107, 131, 142,,143,184,242,253,588,931,935,565	243,311	109,626
6	Property Taxes - Capital Leases West Virginia	186,747	1,034,110	408	980,449	240,408
7	Unamortized Credit Line Fees	990,930	419,172	431	473,363	936,739
8	Def Lease Assets - Non Taxable	299,811	1,241,206	142, 143	1,419,384	121,633
9	Deferred Urea Expense	2,181,640	23,449,931	142, [(b)] 154, 186	23,820,627	1,810,944
10	VA Sales/Use Tax Surcharge	(65,850)	2,715,131	142	1,759,968	889,313
11	PJM Transmission True-up	7,824,410	65,857,950	186, 456, 565	15,585,112	58,097,248
12	Railroad Cars Subleased	1,837	19,235	151,236, 408	21,072	
47	Miscellaneous Work in Progress	2,480,420				1,589,574
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	99,027,251				154,548,754

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DecreaseInMiscellaneousDeferredExpenseAccountCharged
142, 143, 232, 253, 593, 243, 588
(b) Concept: DecreaseInMiscellaneousDeferredExpenseAccountCharged
142, 232, 154

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	Interest Expense Capitalized for Tax	57,333,967	58,539,612
3	CIAC	13,405,577	14,192,476
4	DSIT Normalized	11,281,512	4,080,120
5	Accrued Book Removal Costs	67,667,198	63,574,216
6	Accrued Book ARO Expenses	89,833,622	94,361,562
7	Other	24,601,332	32,016,339
8	TOTAL Electric (Enter Total of lines 2 thru 7)	264,123,208	266,764,325
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	232,973,277	[a]201,442,859
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	497,096,485	468,207,184

Notes

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Notes

Line 17 Other - Detail		Balance at Beginning of Year	Balance at End of Year
Acc Def Income Taxes - Federal - Hdg-CF-Int Rate		613,456	569,578
Non Utility Items - 190.2		9,383,500	26,349
SFAS 109-Regulatory Assets - 190.3, 190.4 & 190.6		219,495,179	197,742,300
Accu Def Income Taxes Pension-OCI		3,481,141	3,104,632
Total	$	232,973,276	$ 201,442,859

Line 18		
Reconciliation of details applicable to Account 190,Line 18,Columns(b)and(c) :		
Balance at Beginning of Year	$	497,096,485
(Less) Amounts Debited to:		
(a) Account 410.1		(76,450,604)
(b) Account 410.2		(9,787,316)
(c) 1823/254/219/129/427		(130,061,382)
(Plus) Amounts Credited to:		
(a) Account 411.1		72,414,939
(b) Account 411.2		7,670,475
(c) 1823/254/219/129/427		107,324,588
Balance at End of Year	$	468,207,185

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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		30,000,000			13,499,500	260,457,768				
5	Total	30,000,000			13,499,500	260,457,768				
6	Preferred Stock (Account 204)									
7										
8										
9										
10	Total									
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2024-04-09	Year/Period of Report End of: 2023/ 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	1,825,984,503
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	1,825,984,503
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	433
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	433
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	2,651,030
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	5,897,810
16	Ending Balance Amount	8,548,840
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	1,834,533,776

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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)
1	Bonds (Account 221)										
2	Appalachian Consumer Rate Relief Funding LLC										
3	Tranche A-1, 2.0076%, Due 2024		215,800,000		2,416,193		[(a)]9,879	11/15/2013	02/01/2024	11/15/2013	02/01/2023
4	Tranche A-2, 3.7722%, Due 2031		164,500,000		1,841,815		[(b)]7,530	11/15/2013	08/01/2031	11/15/2013	08/01/2028
5	Subtotal		380,300,000		4,258,008		17,409				
6	Reacquired Bonds (Account 222)										
7											
8											
9											
10	Subtotal										
11	Advances from Associated Companies (Account 223)										
12											
13											
14											
15	Subtotal										
16	Other Long Term Debt (Account 224)										
17	Amos Project, Series 2009A, Due 2042 -WV Economic Development Authority, Solid Waste Disposal Facility - 3.75% Bonds		54,375,000		410,584			05/15/2018	12/01/2042	05/15/2018	06/01/2022
18					338,283			06/01/2022	12/01/2042	06/01/2022	06/01/2025
19	Amos Project, Series 2009B, Due 2042 -WV Economic Development Authority, Solid Waste Disposal Facility - 3.75% Bonds		50,000,000		377,548			05/15/2018	12/01/2042	05/15/2018	06/01/2022
20					321,042			06/01/2022	12/01/2042	06/01/2022	06/01/2025
21	Mountaineer Project, Series 2008A, Due 2036 -WV Economic Development Authority, Solid Waste Disposal Facility -Variable Rate Demand Bonds		75,000,000		370,548			03/17/2011	02/01/2036	01/13/2016	02/01/2036
22	Mountaineer Project, Series 2008B, Due 2036 -WV Economic Development Authority, Solid Waste Disposal Facility -Variable Rate Demand Bonds		50,275,000		291,961			03/17/2011	02/01/2036	03/10/2016	02/01/2036
23	Amos Project, Series 2010A, Due 2038 -WV Economic Development Authority, Solid Waste Disposal Facility - 0.625% Bonds - Subject to mandatory tender for purchase (puttable) on 12/15/2025		50,000,000		649,267			05/19/2010	12/01/2038	05/19/2010	12/01/2038
24					384,107			12/23/2020	12/01/2038	12/23/2020	12/15/2025
25	Amos Project, Series 2015A, Due 2040 -WV Economic Development Authority, Solid Waste Disposal Facility - 2.550% Bonds - Subject to mandatory tender for purchase (puttable) on 04/01/2024		86,000,000		642,924			04/01/2015	03/01/2040	04/01/2015	04/01/2019
26					555,367			04/01/2019	04/01/2024	04/01/2019	04/01/2024
27	Amos Project, Series 2011A, Due 2041 -WV Economic Development Authority, Solid Waste Disposal Facility - 1.000% Bonds - Subject to mandatory tender for purchase (puttable) on 09/01/2025		65,350,000		416,278			09/01/2016	01/01/2041	09/01/2016	09/01/2020
28					427,620			09/01/2020	01/01/2041	09/01/2020	09/01/2025
29	SENIOR UNSECURED NOTES										
30	5.800% Senior Unsecured Notes, Series L, Due 2035		250,000,000		2,334,997		1,900,000	09/29/2005	10/01/2035	09/29/2005	10/01/2035
31	5.950% Senior Unsecured Notes, Series H, Due 2033		200,000,000		1,900,000		422,000	05/05/2003	05/15/2033	05/05/2003	05/15/2033
32	Interest Expense amortization of Cash Flow Hedge										
33	6.375% Senior Unsecured Notes, Series N, Due 2036		250,000,000		2,266,382		757,500	04/10/2006	04/01/2036	04/10/2006	04/01/2036

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)
34	Interest Expense amortizations of Cash Flow Hedges										
35	6.700% Senior Unsecured Notes, Series P, Due 2037		250,000,000		2,348,344		62,500	08/17/2007	08/15/2037	08/17/2007	08/15/2037
36	7.000% Senior Unsecured Notes, Series Q, Due 2038		500,000,000		4,447,060		3,300,000	03/25/2008	04/01/2038	03/25/2008	04/01/2038
37	Interest Expense amortization of Cash Flow Hedges										
38	4.400% Senior Unsecured Notes, Series U, Due 2044		300,000,000		2,973,178		2,082,000	05/08/2014	05/15/2044	05/08/2014	05/15/2044
39	3.400% Senior Unsecured Notes, Series V, Due 2025		300,000,000		2,312,703		1,065,000	05/18/2015	06/01/2025	05/18/2015	06/01/2025
40	4.450% Senior Unsecured Notes, Series W, Due 2045		350,000,000		3,483,819		2,530,500	05/18/2015	06/01/2045	05/18/2015	06/01/2045
41	3.300% Senior Unsecured Notes, Series X, Due 2027		325,000,000		2,648,060		1,657,500	05/11/2017	06/01/2027	05/11/2017	06/01/2027
42	4.500% Senior Unsecured Notes, Series Y, Due 2049		400,000,000		4,158,436		2,736,000	03/06/2019	03/01/2049	03/06/2019	03/01/2049
43	3.700% Senior Unsecured Notes Series Z, Due 2050		500,000,000		5,106,633		2,955,000	05/14/2020	05/01/2050	05/14/2020	05/01/2050
44	2.700% Senior Unsecured Notes Series AA, Due 2031		500,000,000		4,160,254		2,203,000	03/11/2021	04/01/2031	03/11/2021	04/01/2031
45	- Interest Expense re amortization of Cash Flow Hedges										
46	4.500% Senior Unsecured Notes Series BB, Due 2032, Virginia State Corporation Commission Authority PUR-2021-00271, Tennessee Public Utility Commission Docket No. 21-00126		500,000,000		4,188,837		1,315,000	08/01/2022	08/01/2032	08/01/2022	08/01/2032
47	SALE / LEASEBACK OF PROPERTY										
48	Agreement with City of Bedford, VA re Skimmer Station		2,559,040					06/07/1996	06/06/2026	06/07/1996	06/06/2026
49	Floating Credit Facility		125,000,000		515,004			05/26/2022	05/26/2025	05/26/2022	05/26/2025
50	[c] Variable Rate Credit Facility		300,000,000		25,165			07/22/2022	06/28/2024	07/22/2022	06/28/2024
46	Subtotal		5,483,559,040		48,054,401		22,986,000				
33	TOTAL		5,863,859,040								

Line No.	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1		
2		
3		
4	147,717,358	5,895,380
5	147,717,358	5,895,380
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17	54,375,000	2,039,062
18		
19	50,000,000	1,875,000
20		
21	75,000,000	2,393,822
22	50,275,000	1,608,318
23	50,000,000	312,500
24		
25	86,000,000	2,193,000
26		
27	65,350,000	653,500
28		
29		
30	250,000,000	14,500,000
31	200,000,000	11,900,000
32		37,072
33	250,000,000	15,937,500
34		(194,198)
35	250,000,000	16,750,000
36	500,000,000	35,000,000
37		159,670
38	300,000,000	13,200,000
39	300,000,000	10,200,000
40	350,000,000	15,575,000
41	325,000,000	10,725,000
42	400,000,000	18,000,000
43	500,000,000	18,500,000
44	500,000,000	13,500,000
45		(1,059,374)
46	500,000,000	22,500,000
47		
48	1,701,032	239,104
49	125,000,000	7,962,662
50	300,000,000	14,147,684
46	5,482,701,032	248,655,322
33	5,630,418,390	[d]254,550,702

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: BondsDiscount

Issuance : Tranche A-1, 2.0076%, Due 2024
Principal Amount : $215,800,000
Date of Issuance : 11/15/2013
Date of Maturity : 02/01/2024

- Date of maturity (02/01/2024) is when all required payments must be made.
- The amortization period end date being used (02/01/2023) is the scheduled final payment date.

(b) Concept: BondsDiscount

Issuance : Tranche A-2, 3.7722%, Due 2031
Principal Amount : $164,500,000
Date of Issuance : 11/15/2013
Date of Maturity : 08/01/2031

- Date of maturity (08/01/2031) is when all required payments must be made.
- The amortization period end date being used (08/01/2028) is the scheduled final payment date.

(c) Concept: ClassAndSeriesOfObligationCouponRateDescription

Issuance : Variable Rate Credit Facility
Principal Amount : $300,000,000
Issuance Date : 07/22/2022
Maturity Date : 06/28/2024
Remarketed Date : 05/19/2023
_ The $100M debt issued on 07/22/2022 upsize to $300M on 05/19/2023

- Issuance expense will be amortized through June 2024

(d) Concept: InterestExpenseOnLongTermDebtIssued

The difference between the total interest on this schedule and the total of accounts 427 and 430 is due to interest on short-term advances from the AEP Money Pool.

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	294,423,705
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]277,109,835
28	Show Computation of Tax:	
29		
30		
31		
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43		
44		

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: FederalTaxNetIncome

FOOTNOTE DATA

Schedule Page: 261 Line No.: 28 Column: b

Net Income for the Year per Page 117	294,424
Federal Income Taxes	1,668
State Income Taxes	12,490
Pre-Tax Book Income	**308,582**
Other	12,094
Excess Tax vs Book Depr	86,703
AFUDC & Other Capitalization Differences	(29,011)
Book/Tax Mixed Service Cost Adj	(62,597)
Removal Costs	(66,801)
Pollution Control Equipment	39,644
Provision for Possible Revenue Refunds	11,321
Deferred Fuel Costs	265,508
Pension Expenses	41
Defd Costs & Carrying Charges	(10,643)
Premium of Reacquired Debt	3,715
SFAS 106 - Post Retire Benefit Exp	23,344
Accrued Bk ARO Expense - SFAS 143	589
Capitalized Software	18,548
Book/Tax Unit of Property Adj	(280,478)
Virginia T-RAC	(7,360)
Deferred Storm Damage	(19,500)
Incentive Compensation Plans	168
Accrued Book Severance Benefits	1,660
Extra Loss - Plant Retirements	3,548
Stock Compensation	774
COVID-19 Incremental Costs	233
Charitable Contribution Carryforward	
Regulatory Asset - SFAS 143 - ARO	(22,972)
Taxable Income before State Taxes	277,110
State & Local Current Tax	6,314
Federal Taxable Income	270,796
FIT on Current Year Taxable Income	56,867
NOL Deferred Tax Asset	0
Tax Credits	826
R & D CREDIT - CURRENT	191
Electric Production Credit	53
Tax Provision Adjustments	0
Estimated Tax Currently Payable (a)	55,797
Adjustments of Prior Year's Accruals	6,409
Tax Expense for R/C of Net Operating Loss (Prior Yr)	
Estimated Current Federal Income Taxes	62,206

(a) Represents the allocation of the estimated current year net operating tax income of American Electric Power Company, Inc.

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 2022 System Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by October 2023. 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: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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 Accrued (Account 236) (e)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR Taxes Accrued (Account 236) (j)	BALANCE AT END OF YEAR Prepaid Taxes (Included in Account 165) (k)
1	Federal Income	Federal Tax			(10,178,875)		56,240,859	41,666,013		4,395,971	0
2	**Subtotal Federal Tax**				(10,178,875)	0	56,240,859	41,666,013		4,395,971	0
3					0	0				0	0
4	**Subtotal State Tax**				0	0	0	0	0	0	0
5	City Tax	Local Tax		2019	8,906					8,906	
6	City Tax	Local Tax	NC	2021		0	2,118			2,118	0
7	Municipal B&O Tax	Local Tax	WV	2022	3,488,001		(3,489)	3,484,512		0	
8	Municipal B&O Tax	Local Tax	WV	2023			15,590,843	11,991,698		3,599,145	
9	**Subtotal Local Tax**				3,496,907	0	15,589,472	15,476,210	0	3,610,169	0
10	Public	Other Taxes	TN	2020						0	
11		Other Taxes	TN	2021						0	
12		Other Taxes	WV	2020						0	
13		Other Taxes	WV	2021						0	
14	**Subtotal Other Tax**				0	0	0	0	0	0	0
15	Pers Prop Leased	Property Tax	OH	2022			8	8		0	0
16		Property Tax	OH	2023			18	18		0	0
17		Property Tax	VA	2020	0		1,911	1,911		0	0
18		Property Tax	VA	2021			1,917	1,917		0	0
19		Property Tax	VA	2022	67,149		(22,402)	44,747		0	
20		Property Tax	VA	2023			553,300	415,405		137,895	0
21		Property Tax	WV	2019			11	11		0	0
22		Property Tax	WV	2020			10	10		0	0
23		Property Tax	WV	2021	21,175		14	21,189		0	
24		Property Tax	WV	2022	375,758		(61,441)	313,689		628	0
25		Property Tax	WV	2023			485,372			485,372	0
26	Real&Pers Prop	Property Tax	AR	2022			1,733	1,733		0	0
27		Property Tax	LA	2023			1,239	1,239		0	0
28		Property Tax	MO	2022	934		(934)			0	0
29		Property Tax	MO	2023			14,617	14,617		0	
30		Property Tax	OH	2021	5,654,266		43,154	5,697,420		0	
31		Property Tax	OH	2022	6,042,154		(250,000)			5,792,154	
32		Property Tax	OH	2023			5,711,000			5,711,000	
33		Property Tax	TN	2022	1,564,865		(83,818)	1,481,047		0	
34		Property Tax	TN	2023			1,505,300			1,505,300	
35		Property Tax	VA	2020			34,348	34,348		0	0
36		Property Tax	VA	2022	1,073,536		220,643	1,294,179		0	0
37		Property Tax	VA	2023			27,090,581	22,925,182		4,165,399	0
38		Property Tax	WV	2021	26,273,009		39,567	26,312,576		0	
39		Property Tax	WV	2022	49,952,862		(725,079)	24,714,711		24,513,072	
40		Property Tax	WV	2023			58,690,467	1,221		58,689,246	
41		Property Tax	WY	2021	302		(302)			0	
42		Property Tax	WY	2022			1,594	1,594		0	0
43		Property Tax	MS	2022			2	2		0	
44		Property Tax	VA	2023			65,405	65,405		0	0
45	**Subtotal Property Tax**				91,026,010	0	93,318,235	83,344,179	0	101,000,066	0
46	**Subtotal Real Estate Tax**				0	0	0	0	0	0	0
47	UNEMPLOYMENT 2023	Unemployment Tax			10,716		89,562	78,141		22,137	
48	STATE UNEMPLOYMENT 2023	Unemployment Tax	KY		341		114	145		310	

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)
49	STATE UNEMPLOYMENT 2023	Unemployment Tax	NC				177	177		0	
50	STATE UNEMPLOYMENT 2023	Unemployment Tax	OH		645		3,910	3,647		908	
51	STATE UNEMPLOYMENT 2023	Unemployment Tax	TN		1		8	7		2	
52	STATE UNEMPLOYMENT 2023	Unemployment Tax	VA		10,028		20,815	22,409		8,434	
53	STATE UNEMPLOYMENT 2023	Unemployment Tax	WV		24,507		153,997	145,698		32,806	
54	**Subtotal Unemployment Tax**				46,238	0	268,583	250,224	0	64,597	0
55		Sales And Use Tax	OH	2022	44,127	20,123	(18,397)	5,607		0	
56		Sales And Use Tax	OH	2023			228,451	205,572		42,176	19,297
57		Sales And Use Tax	TN	2022	11,620		(11,027)	593		0	
58		Sales And Use Tax	TN	2023			9,738	9,718		20	
59		Sales And Use Tax	TX	2022	(14)			(14)		0	
60		Sales And Use Tax	VA	2022	549,824		145,743	695,567		0	
61		Sales And Use Tax	VA	2023	0		4,296,184	4,035,735		260,449	
62		Sales And Use Tax	VA	2022						0	
63		Sales And Use Tax	WV	2022	587,473		13,559	601,032		0	
64		Sales And Use Tax	WV	2023			2,811,421	2,560,853		250,568	
65	**Subtotal Sales And Use Tax**				1,193,030	20,123	7,475,672	8,114,663	0	553,213	19,297
66		Income Tax	IL	2017	(163,298)					(163,298)	0
67		Income Tax	IL	2018	149,311					149,311	0
68		Income Tax	IL	2019	324,392					324,392	0
69		Income Tax	IL	2020	(141,231)					(141,231)	0
70		Income Tax	IL	2021	(169,009)					(169,009)	0
71		Income Tax	IL	2022			0			0	
72		Income Tax	IL	2023			894			894	0
73		Income Tax	KY	2020	(2,361)					(2,361)	0
74		Income Tax	KY	2021	(1,500)					(1,500)	
75		Income Tax	KY	2022	541					541	
76		Income Tax	KY	2023			318			318	
77		Income Tax	MI	2017	(6,145)					(6,145)	0
78		Income Tax	MI	2018	6,918					6,918	
79		Income Tax	MI	2019	3,226					3,226	0
80		Income Tax	MI	2021	(1,586)					(1,586)	0
81		Income Tax	MI	2020	(2,414)					(2,414)	0
82		Income Tax	MI	2023			1,232			1,232	0
83		Income Tax	MULTI	2019	(8,915)					(8,915)	0
84		Income Tax	MULTI	2021	9					9	0
85		Income Tax	MULTI	2023			4,769			4,769	
86		Income Tax	NOL	2011						0	0
87		Income Tax	NOL	2021						0	0
88		Income Tax	TN	2002						0	0

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)
89		Income Tax	TN	2016	(4,104)					(4,104)	0
90		Income Tax	TN	2017	(501,938)					(501,938)	0
91		Income Tax	TN	2018	416,030					416,030	0
92		Income Tax	TN	2019	(204,591)					(204,591)	0
93		Income Tax	TN	2020	(504,784)					(504,784)	0
94		Income Tax	TN	2021	(90,819)					(90,819)	0
95		Income Tax	TN	2022	(154,353)					(154,353)	0
96		Income Tax	TN	2023			4,012			4,012	0
97		Income Tax	VA	2020	8					8	0
98		Income Tax	VA	2021	(8)					(8)	0
99		Income Tax	VA	2023			(6,648)			(6,648)	0
100		Income Tax	WV	2002							
101		Income Tax	WV	2017	(1,489,463)					(1,489,463)	
102		Income Tax	WV	2018	(767,996)					(767,996)	
103		Income Tax	WV	2019	17,011,204					17,011,204	
104		Income Tax	WV	2020	(830,160)					(830,160)	
105		Income Tax	WV	2021	(14,677,829)					(14,677,829)	
106		Income Tax	WV	2022	(483,677)					(483,677)	
107		Income Tax	WV	2023			6,309,563			6,309,563	0
108	**Subtotal Income Tax**				(2,294,542)	0	6,314,140	0	0	4,019,598	0
109		Excise Tax		2022	0	0	12,880	12,880		0	0
110	**Subtotal Excise Tax**				0	0	12,880	12,880	0	0	0
111		Fuel Tax		2023						0	
112	**Subtotal Fuel Tax**				0	0	0	0	0	0	0
113	FICA 2023	Federal Insurance Tax			1,393,496	0	14,304,309	14,731,165		966,640	
114	**Subtotal Federal Insurance Tax**				1,393,496	0	14,304,309	14,731,165	0	966,640	0
115	STATE FRANCHISE	Franchise Tax	KY	2019	1,637					1,637	0
116		Franchise Tax	KY	2020	1,683					1,683	0
117		Franchise Tax	NC	2017	(4,035)					(4,035)	0
118		Franchise Tax	NC	2018	200					200	0
119		Franchise Tax	NC	2019	1,910					1,910	0
120		Franchise Tax	NC	2020	(393)					(393)	0
121		Franchise Tax	NC	2021	(304)					(304)	0
122		Franchise Tax	NC	2022	994		(777)			217	
123		Franchise Tax	NC	2023			217			217	
124		Franchise Tax	TN	2002	0					0	
125		Franchise Tax	TN	2017	88,451					88,451	0
126		Franchise Tax	TN	2018	9,373					9,373	0
127		Franchise Tax	TN	2019	196,218					196,218	0
128		Franchise Tax	TN	2020	241,181					241,181	0
129		Franchise Tax	TN	2021	214,257					214,257	0
130		Franchise Tax	TN	2022	214,257		(44,581)	11,500		158,176	0
131		Franchise Tax	TN	2023			169,676	102,000		67,676	
132		Franchise Tax	WV	2002							
133	**Subtotal Franchise Tax**				965,429	0	124,535	113,500	0	976,464	0
134	**Subtotal Miscellaneous Other Tax**				0	0	0	0	0	0	0
135										0	
136	**Subtotal Other Federal Tax**				0	0	0	0	0	0	0

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)
137		Other State Tax	WV	2002	0					0	
138		Other State Tax	WV	2016	0					0	
139		Other State Tax	WV	2022						0	
140		Other State Tax	OH	2021						0	
141		Other State Tax	OH	2022						0	
142		Other State Tax	WV	2020						0	
143	Public serv comm	Other State Tax	WV	2021						0	
144		Other State Tax	WV	2022	759,000	1,643,192	1,643,192	759,000		0	
145		Other State Tax	WV	2023			522,660	522,660		0	
146		Other State Tax	VA	2018	(68,884)					(68,884)	
147		Other State Tax	VA	2019	(2,350,965)					(2,350,965)	
148		Other State Tax	VA	2020	(344,378)					(344,378)	
149		Other State Tax	VA	2021	1,373,104					1,373,104	
150		Other State Tax	VA	2022	1,390,303			4,582,044		(3,191,741)	
151		Other State Tax	VA	2023			15,441,511	14,902,000		539,511	
152		Other State Tax	FIN48							0	
153	**Subtotal Other State Tax**				758,180	1,643,192	17,607,363	20,765,704	0	(4,043,353)	0
154	**Subtotal Other Property Tax**				0	0	0	0	0	0	0
155	**Subtotal Other Use Tax**				0	0	0	0	0	0	0
156	Ohio CAT Tax	Other Ad Valorem Tax	OH	2022	2,400		11,666	14,066		0	
157		Other Ad Valorem Tax	OH	2023			12,318	12,318		0	
158	WV Business & Occupation	Other Ad Valorem Tax	WV	2021			(29,208)	(29,208)		0	
159		Other Ad Valorem Tax	WV	2022	2,100,331		(71,281)	2,029,050		0	
160		Other Ad Valorem Tax	WV	2023			34,701,843	32,726,285		1,975,558	
161	**Subtotal Other Advalorem Tax**				2,102,731	0	34,625,338	34,752,511	0	1,975,558	0
162		Other License And Fees Tax	WV	2019	(72)		72			0	0
163		Other License And Fees Tax	WV	2020	(260)		260			0	0
164		Other License And Fees Tax	WV	2021	(410)		410			0	0
165		Other License And Fees Tax	WV	2022	(1,125)		1,145	20		0	0
166		Other License And Fees Tax	WV	2023	0		495	495		0	0
167	**Subtotal Other License And Fees Tax**				(1,867)	0	2,382	515	0	0	0
168	**Subtotal Advalorem Tax**				0	0	0	0	0	0	0
169	**Subtotal Other Allocated Tax**				0	0	0	0	0	0	0
170	**Subtotal Severance Tax**				0	0	0	0	0	0	0
171	**Subtotal Penalty Tax**				0	0	0	0	0	0	0
172	**Subtotal Other Taxes And Fees**				0	0	0	0	0	0	0
40	TOTAL				88,506,737	1,663,315	245,883,768	219,227,564		113,518,923	19,297

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	67,930,629			(11,689,770)
2	67,930,629			(11,689,770)
3				
4	0	0	0	0
5				
6				2,118
7				(3,489)
8	15,540,444			50,399
9	15,540,444	0	0	49,028
10				
11				
12				
13				
14	0	0	0	0
15	8			
16	18			
17	1,911			
18	1,917			
19	(22,402)			
20	553,300			
21	11			
22	10			
23	14			
24	125,306			(186,747)
25	244,964			240,408
26				1,733
27				1,239
28				(934)
29				14,617
30	43,154			
31	5,792,154			(6,042,154)
32				5,711,000
33	(83,315)			(503)
34	1,489,668			15,632
35	34,348			
36	220,643			
37	26,498,043			592,538
38	25,712,991			(25,673,424)
39	23,973,108			(24,698,187)
40				58,690,467
41				(302)
42				1,594
43				2
44				65,405
45	84,585,851	0	0	8,732,384
46	0	0	0	0
47	55,474			34,088
48	386			(272)
49	102			75
50	2,402			1,508
51	5			3
52	8,000			12,815
53	92,384			61,609

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)
54	158,754	0	0	109,826
55				(18,397)
56	(187)			228,638
57	(48)			(10,979)
58	(1)			9,739
59				
60				145,743
61	133,975			4,162,209
62				
63	42			13,517
64	(478)			2,811,899
65	133,303	0	0	7,342,369
66				
67				
68				
69				
70				
71				
72	2,917			(2,023)
73				
74				
75				
76	637			(319)
77				
78				
79				
80				
81				
82	1,296			(64)
83				
84				
85	4,769			
86				
87				
88				
89				
90				
91				
92				
93				
94				
95				
96	13,150			(9,138)
97				
98				
99	(6,648)			
100				
101				
102				
103				
104				
105				
106				

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)
107	6,623,504			(313,941)
108	6,639,625	0	0	(325,485)
109	12,880			
110	12,880	0	0	0
111				
112	0	0	0	0
113	8,364,693			5,939,616
114	8,364,693	0	0	5,939,616
115				
116				
117				
118				
119				
120				
121				
122	(777)			
123	217			
124				
125				
126				
127				
128				
129				
130	(44,581)			
131	169,676			
132				
133	124,535	0	0	0
134	0	0	0	0
135				
136	0	0	0	0
137				
138				
139				
140				
141				
142				
143				
144				1,643,192
145				522,660
146				
147				
148				
149				
150				
151	15,441,511			
152				
153	15,441,511	0	0	2,165,852
154	0	0	0	0
155	0	0	0	0
156	11,666			
157	12,318			
158	(29,208)			
159	(74,392)			3,111

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)
160	38,366,900			(3,665,057)
161	38,287,284	0	0	(3,661,946)
162	72			0
163	260			0
164	410			0
165	1,145			0
166	495			0
167	2,382	0	0	0
168	0	0	0	0
169	0	0	0	0
170	0	0	0	0
171	0	0	0	0
172	0	0	0	0
40	237,221,891			8,661,874

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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%				411.1					
3	4%				411.1					
4	7%				411.1					
5	10%	295,219	411.1		411.1	10,560		284,659	32 Years	
6	State DITC		411.1		411.1					
7	30%				411.1					
8	TOTAL Electric (Enter Total of lines 2 thru 7)	295,219				10,560		284,659		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL	295,219						284,659		

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	T.V. Pole Attachments	2,130,509	172/186/454	11,967,873	12,130,457	2,293,093
2	Deferred Gain - Fiber Optic Leases - Amortize through June 2026	1,481,361	108/411	729,974		751,387
3	Deferred Revenue - Fiber Optic Lines Sold - Amortize through Jan 2025	45,187	451	36,421		8,766
4	Customer Advance Receipts	18,241,480	142	18,241,480	17,651,736	17,651,736
5	Other Deferred Credits	1,169,226	142/143/186	937,279	850,955	1,082,902
6	Def Equity Income-Securitization	1,926,016	456	316,111		1,609,905
7	ABD - Deferred Revenues				46,151	46,151
8	Reliability First FAC-003 Assessment	637,769	242	68,541		569,228
9	Contr In Aid of Constr Advance	1,854,835	107/108	1,854,835	1,207,077	1,207,077
10	Collateral Held During Construction	500,000				500,000
11	PJM Transmission True-Up	5,479,391	449/229/456/565	10,913,203	38,769,254	33,335,442
47	TOTAL	33,465,774		45,065,717	70,655,630	59,055,687

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

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

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

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities	218,556,514	2,279,615	14,562,936							206,273,193
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	218,556,514	2,279,615	14,562,936							206,273,193
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other - SFAS 109	[a](87,727,771)					254	804,668	254	4,699,155	(83,833,284)
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	130,828,743	2,279,615	14,562,936				804,668		4,699,155	122,439,909
18	Classification of TOTAL										
19	Federal Income Tax	130,828,743	2,279,615	14,562,936				804,668		4,699,155	122,439,909
20	State Income Tax										
21	Local Income Tax										

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Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesAcceleratedAmortizationProperty

Description Year Page 272-273	Balance at Beginning	Amounts Debited to Acc 410.2	Amounts Credits to Acc 411.2	Debit Adjust	Credit Adjust	Balance End of
SFAS 109	(87,727,771)			(804,668)	4,699,154	(83,833,285)
Total line 16	(87,727,771)			(804,668)	4,699,154	(83,833,285)

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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 Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)	CHANGES DURING YEAR Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits Account Credited (g)	ADJUSTMENTS Debits Amount (h)	ADJUSTMENTS Credits Account Debited (i)	ADJUSTMENTS Credits Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	1,982,300,962	177,756,198	109,435,095		46,034,853					2,004,587,212
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	1,982,300,962	177,756,198	109,435,095		46,034,853					2,004,587,212
6	[(a)] Others	(422,627,470)					1823/254	27,696,058	1823/254	89,916,022	(360,407,506)
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,559,673,492	177,756,198	109,435,095		46,034,853		27,696,058		89,916,022	1,644,179,706
10	Classification of TOTAL										
11	Federal Income Tax	1,559,673,492	177,745,936	155,459,686				27,696,058		89,916,022	1,644,179,706
12	State Income Tax										
13	Local Income Tax										

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Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfNonUtilityAccountDetails

Line 6 Footnote

	Beg Bal	Debits	Credits	End Bal
SFAS 109	(422,627,470)	27,696,058	89,916,022	(360,407,506)
Total Other - Line 6	(422,627,470)	27,696,058	89,916,022	(360,407,506)

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	DSIT ENTRY - NORMALIZED	86,503,771		1,775,677							84,728,094
4	DEFD TAX GAIN - APCO WV SEC REG ASSET	33,919,954		5,567,179							28,352,775
5	REG ASSET-Glen Lyn ARO	62,979,346	2,231,741								65,211,087
6	UNDER RECOVERY FUEL COST	146,236,132	7,537,023	63,293,790							90,479,365
7	ACCRUED BK PENSION EXPENSE	24,998,691	1,554,203								26,552,894
8	Other	36,593,160	48,423,439	58,214,480				563,534	283	6	26,238,591
9	TOTAL Electric (Total of lines 3 thru 8)	391,231,054	59,746,406	128,851,126				563,534		6	321,562,806
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	[a]412,235,192			290,920	1,692,203	1823/254	548,425,979	1823/254	534,027,618	396,435,548
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	803,466,246	59,746,406	128,851,126	290,920	1,692,203		548,989,513		534,027,624	717,998,354
20	Classification of TOTAL										
21	Federal Income Tax	484,042,655	55,122,824	124,496,806	290,920	1,692,203		122,214,786		117,420,038	408,472,642
22	State Income Tax	319,423,591	4,623,582	4,354,320				426,774,727		416,607,586	309,525,712
23	Local Income Tax										

NOTES

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Line 18 Footnote

	Beg Bal	Dr 410.1	Cr 411.1	Dr 410.2	Cr 411.2	Debits	Credits	End Bal
Provision Optimizaton						1,999,582	9,005,907	7,006,325
Hedge- Cash Flow	2,369,137					265,733		2,103,404
Non-Utility	1,780,451			290,920	1,692,203	—		379,168
SFAS 109	408,085,603					546,160,664	525,021,711	386,946,650
Total	412,235,191			290,920	1,692,203	548,425,979	534,027,618	396,435,547

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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 Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	FAS 109 Deferred Federal Income Tax	676,369,983	182, 190, 236, 282, 283, 409, 411	95,105,820	11,696,411	592,960,574
2	FAS 109 Deferred State Income Tax	20,779,749		0	0	20,779,749
3	PJM Trans Enhancement Settlement for Refund	9,755,152	142	3,273,596	0	6,481,556
4	Unrealized Gain On Forward Commitments	34,540,395	175, 182	39,393,922	4,853,528	1
5	VA A.6 RPS RAC Over Recovery	109,934	403	971,473	1,031,557	170,018
6	VA Base Rate & RCR Rider Provision Interest, Case No. PUR-2020-0015	80,916	431	202,606	121,690	0
7	VA Broadband Over Recovery	4,042,716	403	3,181,582	401,751	1,262,885
8	VA E-RAC Over Recovery	803,783	501	3,816,475	4,551,550	1,538,858
9	VA EE-RAC Over Recovery, Case No. PUR - 2017-00126	4,932,126	908	2,619,355	917,812	3,230,583
10	VA RPS-RAC Over Recovery	13,582,890	555	11,016,697	39,208	2,605,401
11	WV Broadband Over Recovery	901,043	403	650,398	956,172	1,206,817
12	WV Business Ready Site Program Over Recovery	122,149	403	88,385	191,766	225,530
13	VA A.5 PCAP RAC Over Recovery	0	555	581,598	963,366	381,768
14	WV Renewable Energy Tariff Over Recovery	0	403	31,895	62,672	30,777
15	PJM Transmission True-up Deferral	0		0	19,654,584	19,654,584
41	TOTAL	766,020,836		160,933,802	45,442,067	650,529,101

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	1,614,401,806	1,565,631,035	10,125,697	11,159,403	812,538	812,256
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	700,214,915	646,203,889	5,728,265	6,065,671	140,754	139,326
5	Large (or Ind.) (See Instr. 4)	779,924,490	667,883,583	8,709,584	8,848,569	4,135	4,142
6	(444) Public Street and Highway Lighting	10,240,920	8,697,798	63,249	63,099	1,684	1,681
7	(445) Other Sales to Public Authorities	96,137,358	78,837,545	740,883	779,972	6,406	6,350
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	3,200,919,489	2,967,253,850	25,367,677	26,916,713	965,517	963,755
11	(447) Sales for Resale	323,532,150	410,610,220	5,107,607	4,894,856	8	9
12	TOTAL Sales of Electricity	3,524,451,639	3,377,864,069	30,475,284	31,811,570	965,525	963,764
13	(Less) (449.1) Provision for Rate Refunds	39,081,549	20,664,643				
14	TOTAL Revenues Before Prov. for Refunds	3,485,370,090	3,357,199,426	30,475,284	31,811,570	965,525	963,764
15	Other Operating Revenues						
16	(450) Forfeited Discounts	4,854,042	4,764,442				
17	(451) Miscellaneous Service Revenues	3,656,875	3,809,400				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	21,395,434	30,173,965				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	44,081,720	60,718,871				
22	(456.1) Revenues from Transmission of Electricity of Others	193,381,502	169,442,448				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	267,369,573	268,909,126				
27	TOTAL Electric Operating Revenues	3,752,739,663	3,626,108,552				

Line12, column (b) includes $ (32,569,232) of unbilled revenues.
Line12, column (d) includes (263,738) MWH relating to unbilled revenues

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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					
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45					
46	TOTAL				

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Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	GS - General Sales	23	2,918	0		0.1269
2	GS-TOD - GENERAL SERVICE TOD	10	1,199			0.1199
3	MGS - MEDIUM GENERAL SERVICE	1	332			0.3320
4	OL-Outdoor Lighting	64,014	12,746,987			0.1991
5	RS - Residential Service	10,153,264	1,614,205,879	808,291	12,561	0.1590
6	RSE - Residential Emp.	59,500	9,080,524	3,924	15,163	0.1526
7	RS-EV RESIDENTIAL SERVICE PLUG IN ELECTRIC VEHICLE CHARGING	482	(10,410)	116	4,155	(0.0216)
8	RS-LM-TOD Res. Load MGMT	218	33,479	15	14,533	0.1536
9	RS-TOD-Residential TOD	2,673	400,523	190	14,068	0.1498
10	SGS-Small Gen. Service	165	22,310	2	82,500	0.1352
11	PA - PUBLIC AUTHORITY					
12	Misc Adjustments					
41	TOTAL Billed Residential Sales	10,280,350	1,636,483,741	812,538	12,652	0.1592
42	TOTAL Unbilled Rev. (See Instr. 6)	(154,653)	(22,081,935)			0.1428
43	TOTAL	10,125,697	1,614,401,806	812,538	12,462	0.1594

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	Commonwealth of VA	41	5,776	1	41,000	0.1409
2	Estimated	863	103,927			0.1204
3	GS - GENERAL SERVICE	3,467,519	413,938,277	19,928	174,002	0.1194
4	GS-PA - GENERAL SERVICE-PA	783	105,006	7	111,857	0.1341
5	GS-TOD - GENERAL SERVICE TOD	43,384	5,353,542	690	62,875	0.1234
6	IP-Industrial Power Service	7,019	514,672	1	7,019,000	0.0733
7	LCP-Large Capacity Power	472,889	41,159,801	46	10,280,196	0.0870
8	LGS-TOD - Large General Service-T	25,706	3,484,212	82	313,488	0.1355
9	LPS-Large Power Service	301,723	27,382,043	22	13,714,682	0.0908
10	LPS-TOD-Large Power Ser TOD	23,239	2,593,220	3	7,746,333	0.1116
11	MGS-Medium General Service	248,302	37,508,615	2,974	83,491	0.1511
12	OL-Outdoor Lighting	64,175	10,412,698	0		0.1623
13	RS-Residential Service	24	3,338	0		0.1391
14	SGS-Small General Service	800,966	119,600,518	111,535	7,181	0.1493
15	SGS-PA - SMALL GENERAL SERVICE-PA	1	211	0		0.2110
16	SGS-TOD-Small General Service	3,143	449,849	546	5,756	0.1431
17	SS-School Service	241,751	29,718,753	1,036	233,350	0.1229
18	SWS-Sanctuary Worship	94,941	14,680,852	3,882	24,457	0.1546
19	Winterplace	1,947	367,366	1		0.1887
20	PA - PUBLIC AUTHORITY					
21	Misc Adjustments					
41	TOTAL Billed Small or Commercial	5,798,416	707,382,676	140,754	41,195	0.1220
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(70,151)	(7,167,761)			0.1022
43	TOTAL Small or Commercial	5,728,265	700,214,915	140,754	40,697	0.1222

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	Armstrong	64,834	4,137,182	1	64,834,000	0.0638
2	Constellium	195,844	13,302,124	1	195,844,000	0.0679
3	Estimated	(55,338)	(3,465,920)			0.0626
4	Felman	218,743	12,728,464	1	218,743,000	0.0582
5	GS-General Service	880,344	106,268,278	1,327	663,409	0.1207
6	GS-PA - GENERAL SERVICE-PA	600	66,799			0.1113
7	GS-TOD-General Service TOD	1,637	202,609	18	90,944	0.1238
8	IP-Industrial Power Service	241,325	15,794,151	2	120,662,500	0.0654
9	LCP-Large Capacity Power	2,390,493	201,006,991	99	24,146,394	0.0841
10	LGS-TOD - Large General Service-T	494	93,027	3	164,667	0.1883
11	LPS-Large Power Service	3,182,837	283,668,492	98	32,477,929	0.0891
12	LPS-TOD-Large Power Ser TOD	977,455	94,741,071	30	32,581,833	0.0969
13	MGS-Medium General Service	130,576	20,135,583	402	324,816	0.1542
14	OL-Outdoor Lighting	6,257	932,899			0.1491
15	SGS-Small General Service	20,702	2,927,921	2,151	9,624	0.1414
16	WV Manufacturing	479,882	28,209,984	1	479,882,000	0.0588
17	WV Recycle	10,100	1,534,134	1	10,100,000	0.1519
18	APCo Rider		830,953			
19	Misc Adjustments					
41	TOTAL Billed Large (or Ind.) Sales	8,746,785	783,114,742	4,135	2,115,305	0.0895
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(37,201)	(3,190,252)			0.0858
43	TOTAL Large (or Ind.)	8,709,584	779,924,490	4,135	2,106,308	0.0895

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	Commonwealth of VA	3,531	581,720	556	6,351	0.1647
2	Estimated	(2)	22,953			(11.4765)
3	GS-General Service	1,547	188,033	22	70,318	0.1215
4	GS-TOD-General Service TOD	584	55,473	5	116,800	0.0950
5	MGS-PA-Med Gen Ser - PA	5	927	1	5,000	0.1854
6	OL-Outdoor Lighting	185	29,470			0.1593
7	SGS-Small General Service	2,475	380,483	585	4,231	0.1537
8	SGS-PA -Small Gen Ser - PA	901	156,661	323	2,789	0.1739
9	SL-Street Lighting	54,154	8,822,169	192	282,052	0.1629
10	Misc Adjustments					
41	TOTAL Billed Public Street and Highway Lighting	63,380	10,237,889	1,684	37,637	0.1615
42	TOTAL Unbilled Rev. (See Instr. 6)	(131)	3,031			
43	TOTAL	63,249	10,240,920	1,684	37,559	0.1619

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	Commonwealth of VA	126,694	17,923,649	924	137,115	0.1415
2	Estimated	(184)	(18,386)			0.0999
3	Flood Walls	148	13,095	21	7,048	0.0885
4	GS-General Service	23,980	2,647,277	19	1,262,105	0.1104
5	GS-PA -General Service -PA	350,575	42,254,596	634	552,957	0.1205
6	GS-TOD-PA-Gen Ser TOD -PA	3,089	402,289	107	28,869	0.1302
7	LPS-TOD - LARGE POWER SERVICE TOD	18,778	1,696,150	1	18,778,000	0.0903
8	LPS-TOD-PA Large Pow Ser	21,920	2,417,111	3	7,306,667	0.1103
9	MGS - MEDIUM GENERAL SERVICE	1,157	171,376	9	128,556	0.1481
10	MGS-PA-Med Gen Ser - PA	152,233	22,188,521	648	234,927	0.1458
11	OL-Outdoor Lighting	2,872	487,490			0.1697
12	PA-PEV PUBLIC AUTHORITY PLUG IN ELECTRIC VEHICLE CHARGING	130	20,867	2	65,000	0.1605
13	Public Authority-Large General Svc-TOD-Pri	92	10,789	1	92,000	0.1173
14	Public Authority-Large General Svc-TOD-Sec	4,864	677,219	26	187,077	0.1392
15	SGS-Small General Service	482	69,525	35	13,771	0.1442
16	SGS-PA- Small Gen Ser - PA	44,106	6,287,290	3,976	11,093	0.1425
17	PA-PEV PUBLIC AUTHORITY					
18	APCo Rider					
19	Misc Adjustments					
41	TOTAL Billed Other Sales to Public Authorities	750,936	97,248,858	6,406	117,224	0.1295
42	TOTAL Unbilled Rev. (See Instr. 6)	(10,053)	(1,111,500)			
43	TOTAL	740,883	96,137,358	6,406	115,655	0.1298

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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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41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		39,081,549			

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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.
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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	25,639,867	3,234,467,906	965,517	2,324,013	
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(272,189)	(33,548,417)			
43	TOTAL - All Accounts	25,367,678	[a]3,200,919,489	965,517	2,324,013	

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: RevenueFromSalesOfElectricityByRateSchedulesIncludingUnbilledRevenue

FOOTNOTE DATA

Schedule Page: 304.2 Line No.: 32 Column: a

2022 FUEL ADJUSTMENT CLAUSE

ACCT	F1 Codes	Sum of Fuel
4400 RE	GS - GENERAL SERVICE	893
	GS-TOD - GENERAL SERVICE TOD	380
	MGS - MEDIUM GENERAL SERVICE	23
	OL - OUTDOOR LIGHTING	1,280,789
	PA - PUBLIC AUTHORITY	—
	RS - RESIDENTIAL SERVICE	245,900,875
	RSE - RESIDENTIAL SERVICE - EMPLOYEE	809,614
	RS-TOD - RESIDENTIAL SERVICE TOD	110,832
	SGS - SMALL GENERAL SERVICE	5,993
	Unbilled	(4,909,072)
4400 RE	Total	243,200,327
4420 CO	Commonwealth of VA	2,253
	Estimated	78,299
	GS - GENERAL SERVICE	66,154,117
	GS-PA - GENERAL SERVICE-PA	33,994
	GS-TOD - GENERAL SERVICE TOD	1,209,521
	LGS-TOD - LARGE GENERAL SERVICE-TOD	1,008,022
	LPS - LARGE POWER SERVICE	11,711,095
	LPS-TOD - LARGE POWER SERVICE TOD	997,467
	MGS - MEDIUM GENERAL SERVICE	10,552,825
	OL - OUTDOOR LIGHTING	1,448,805
	PA - PUBLIC AUTHORITY	—
	RS - RESIDENTIAL SERVICE	697
	SGS - SMALL GENERAL SERVICE	24,678,744
	SGS-PA - SMALL GENERAL SERVICE-PA	57
	SGS-TOD - SMALL GENERAL SERVICE-TOD	1,736
	SWS - SANCTUARY WORSHIP SERVICE	1,219,366
	SS - SCHOOL SERVICE	—
	Unbilled	(1,836,447)
4420 CO	Total	117,260,552
4420 IN	Estimated	(1,220,517)
	GS - GENERAL SERVICE	23,964,024
	GS-PA - GENERAL SERVICE-PA	25,904
	GS-TOD - GENERAL SERVICE TOD	19,534
	LGS-TOD - LARGE GENERAL SERVICE-TOD	21,197
	LPS - LARGE POWER SERVICE	125,118,800
	LPS-TOD - LARGE POWER SERVICE TOD	42,153,329
	MGS - MEDIUM GENERAL SERVICE	5,613,039
	OL - OUTDOOR LIGHTING	160,467
	SGS - SMALL GENERAL SERVICE	569,801
	Unbilled	(1,258,087)
4420 IN	Total	195,167,490
4440 PU	Commonwealth of VA	192,116
	Estimated	(1,431)
	GS-TOD-PA - GEN SERVICE TOD-PA	206
	OL - OUTDOOR LIGHTING	3,457
	SGS - SMALL GENERAL SERVICE	112
	SGS-PA - SMALL GENERAL SERVICE-PA	38,703
	SL - STREET LIGHTING	1,295,927
	Unbilled	(765)
4440 PU	Total	1,528,326
4450 OT	Commonwealth of VA	6,899,964
	Estimated	(5,458)
	GS - GENERAL SERVICE	1,030,623
	GS-PA - GENERAL SERVICE-PA	15,067,496
	GS-TOD-PA - GEN SERVICE TOD-PA	132,667
	LPS-TOD - LARGE POWER SERVICE TOD	807,836
	LPS-TOD-PA - LARGE POW SER TOD-PA	941,032
	MGS - MEDIUM GENERAL SERVICE	49,659
	MGS-PA - MEDIUM GENERAL SERVICE-PA	6,544,102
	OL - OUTDOOR LIGHTING	123,226
	Public Authority-Large General Svc-TOD-Pri	3,936
	Public Authority-Large General Svc-TOD-Sec	209,081
	SGS - SMALL GENERAL SERVICE	20,646
	SGS-PA - SMALL GENERAL SERVICE-PA	1,894,174
	PA-PEV PUBLIC AUTHORITY	5,580
	Unbilled	(425,464)
4450 OT	Total	33,299,100
Grand Total		590,455,795

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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): Average Monthly NCP Demand (e)	ACTUAL DEMAND (MW): Average Monthly CP Demand (f)	Megawatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	CITY OF RADFORD, VA	RQ	[c] NOTE 1				164,095	4,988,533	10,506,838		15,495,371
2	CITY OF SALEM, VA	RQ	NOTE 1				347,726	10,483,603	24,159,229		34,642,832
3	CRAIG-BOTETOURT ELECTRIC COOP	RQ	NOTE 1				50,250	1,847,773	3,379,079		5,226,852
4	DP&L POWER SERVICES	OS	NOTE 1				(2)		(111)		(111)
5	KINGSPORT	RQ	23				1,942,232	43,754,833	70,869,974	43,442,239	158,067,046
6	OLD DOMINION ELECTRIC	RQ	NOTE 1				146,394	5,252,185	9,777,642		15,029,827
7	PJM INTERCONNECTION	OS	NOTE 1				2,093,829	6,432,482	73,941,169	8,295,839	88,669,490
8	PJM TRANSMISSION FOR RQ CUSTOMERS	RQ	VARIOUS				0			(26,496,495)	(26,496,495)
9	UNITED LIGHT & POWER COMPANY	RQ	151				50,703	1,744,814	3,528,612		5,273,426
10	[a] VIRGINIA TECH	RQ	155				312,380	8,325,112	19,321,294		27,646,406
11	[b] WELLS FARGO SECURITIES, LLC	OS	[d] NOTE 1				0		(22,494)		(22,494)
15	Subtotal - RQ						3,013,780	76,396,853	141,542,668	16,945,744	234,885,265
16	Subtotal-Non-RQ						2,093,827	6,432,482	73,918,564	8,295,839	88,646,885
17	Total						5,107,607	82,829,335	215,461,232	25,241,583	323,532,150

Page 310-311

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
An affiliated company
(b) Concept: NameOfCompanyOrPublicAuthorityReceivingElectricityPurchasedForResale
The PUCO (Public Utilities Commission Ohio) ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning June 2015. APCo, KPCo, I&M and WPCo participated in the auction process and were awarded tranches of OPCo's SSO load.
(c) Concept: RateScheduleTariffNumber
FERC Electric Tariff, First Revised Volume No. 5
(d) Concept: RateScheduleTariffNumber
The PUCO (Public Utilities Commission Ohio) ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning June 2015. APCo, KPCo, I&M and WPCo participated in the auction process and were awarded tranches of OPCo's SSO load.

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	17,922,328	21,677,227
5	(501) Fuel	896,985,858	137,379,824
6	(502) Steam Expenses	45,411,487	42,197,963
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	132,037	174,070
10	(506) Miscellaneous Steam Power Expenses	22,377,898	18,490,892
11	(507) Rents	40,565	42,363
12	(509) Allowances	1,423,286	566,936
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	984,293,459	220,529,275
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,983,094	2,293,937
16	(511) Maintenance of Structures	6,175,854	6,358,982
17	(512) Maintenance of Boiler Plant	49,089,661	57,007,353
18	(513) Maintenance of Electric Plant	17,932,921	18,892,575
19	(514) Maintenance of Miscellaneous Steam Plant	12,518,832	11,578,044
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	88,700,362	96,130,891
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	1,072,993,821	316,660,166
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	1,669,327	1,718,131
45	(536) Water for Power	27,126	25,712
46	(537) Hydraulic Expenses	251,186	1,352,480
47	(538) Electric Expenses	156,175	260,358
48	(539) Miscellaneous Hydraulic Power Generation Expenses	3,885,244	3,738,318

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
49	(540) Rents	346,886	349,955
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	6,335,944	7,444,954
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	187,177	212,204
54	(542) Maintenance of Structures	3,420,508	5,009,165
55	(543) Maintenance of Reservoirs, Dams, and Waterways	2,542,618	2,638,011
56	(544) Maintenance of Electric Plant	3,718,571	4,101,071
57	(545) Maintenance of Miscellaneous Hydraulic Plant	241,486	175,391
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	10,110,360	12,135,842
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	16,446,303	19,580,796
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	148,775	288,478
63	(547) Fuel	10,419,504	34,170,944
64	(548) Generation Expenses	612,472	724,407
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	281,207	180,541
66	(550) Rents	10,967	64
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	11,472,925	35,364,434
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	11	
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant	707,617	202,010
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)	707,628	202,010
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	12,180,553	35,566,444
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	521,965,140	1,079,588,594
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	2,307,787	2,335,645
78	(557) Other Expenses	20,587,167	12,781,533
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	544,860,094	1,094,705,772
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	1,646,480,771	1,466,513,178
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	14,497,305	15,051,026
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,107,572	2,036,410
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	6,757,186	6,563,776
89	(561.5) Reliability, Planning and Standards Development	454,347	488,374
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	1,973,833	1,882,571
93	(562) Station Expenses	1,980,988	1,780,188
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	72,312	176,551
95	(564) Underground Lines Expenses		13
96	(565) Transmission of Electricity by Others	378,126,908	358,817,631
97	(566) Miscellaneous Transmission Expenses	(2,730,975)	23,134,029
98	(567) Rents	65,486	55,949
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	403,304,962	409,986,518
100	Maintenance		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
101	(568) Maintenance Supervision and Engineering	197,766	205,034
102	(569) Maintenance of Structures	97,745	99,343
103	(569.1) Maintenance of Computer Hardware	62,877	31,330
104	(569.2) Maintenance of Computer Software	1,271,974	792,598
105	(569.3) Maintenance of Communication Equipment	73,867	46,987
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,190,733	3,864,777
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	19,635,247	17,538,834
109	(572) Maintenance of Underground Lines	15,808	9,873
110	(573) Maintenance of Miscellaneous Transmission Plant	97,334	97,110
111	TOTAL Maintenance (Total of Lines 101 thru 110)	24,643,351	22,685,886
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	427,948,314	432,672,404
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	5,892,099	5,709,851
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	5,892,099	5,709,851
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)	5,892,099	5,709,851
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	5,696,889	5,837,523
135	(581) Load Dispatching	26,038	21,112
136	(582) Station Expenses	1,688,156	1,776,130
137	(583) Overhead Line Expenses	5,303,327	3,127,806
138	(584) Underground Line Expenses	3,567,101	2,604,693
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	(17,235)	102,739
140	(586) Meter Expenses	2,750,013	2,228,048
141	(587) Customer Installations Expenses	1,039,122	740,288
142	(588) Miscellaneous Expenses	18,014,060	17,624,429
143	(589) Rents	3,116,801	2,848,171
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	41,184,272	36,910,939
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	126,464	166,004
147	(591) Maintenance of Structures	84,722	163,169
148	(592) Maintenance of Station Equipment	2,071,539	1,579,014
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	121,526,890	140,844,272
150	(594) Maintenance of Underground Lines	2,687,539	2,582,506
151	(595) Maintenance of Line Transformers	2,161,370	2,386,920
152	(596) Maintenance of Street Lighting and Signal Systems	695,789	732,379

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
153	(597) Maintenance of Meters	476,999	440,068
154	(598) Maintenance of Miscellaneous Distribution Plant	5,750,045	5,525,168
155	TOTAL Maintenance (Total of Lines 146 thru 154)	135,581,357	154,419,500
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	176,765,629	191,330,439
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	438,503	502,386
160	(902) Meter Reading Expenses	3,101,619	3,613,628
161	(903) Customer Records and Collection Expenses	26,815,430	26,135,341
162	(904) Uncollectible Accounts	7,061,918	5,763,349
163	(905) Miscellaneous Customer Accounts Expenses	142,853	108,140
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	37,560,323	36,122,844
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	528,900	603,866
168	(908) Customer Assistance Expenses	23,030,929	20,754,369
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	28,287	54,574
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	23,588,116	21,412,809
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	117,246	155,789
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	117,246	155,789
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	45,628,882	45,534,021
182	(921) Office Supplies and Expenses	2,801,436	6,365,105
183	(Less) (922) Administrative Expenses Transferred-Credit	7,909,135	5,739,469
184	(923) Outside Services Employed	5,161,457	20,782,504
185	(924) Property Insurance	5,100,106	4,780,211
186	(925) Injuries and Damages	(3,507,486)	(8,073,292)
187	(926) Employee Pensions and Benefits	(10,421,440)	(5,809,498)
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	9,914,640	9,595,185
190	(929) (Less) Duplicate Charges-Cr.	266,616	145,799
191	(930.1) General Advertising Expenses	535,267	403,278
192	(930.2) Miscellaneous General Expenses	10,767,506	10,297,292
193	(931) Rents	1,051,347	1,436,533
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	58,855,964	79,426,071
195	Maintenance		
196	(935) Maintenance of General Plant	12,061,842	12,345,833
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	70,917,806	91,771,904
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	2,389,270,304	2,245,689,218

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Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)
1	BEECH RIDGE ENERGY LLC	OS					247,163			
2	BLUFF POINT WIND ENERGY CENTER	OS					407,538			
3	CAMP GROVE WIND FARM LLC	OS					186,224			
4	FOWLER RIDGE III WIND FARM LLC	OS					200,503			
5	GAULEY RIVER POWERS PARTNERS	OS					170,219			
6	GRAND RIDGE ENERGY II LLC	OS					105,727			
7	GRAND RIDGE WIND FARM 3	OS					96,829			
8	LUMINAIRE TECHNOLOGIES, INC.	OS					696			
9	OLD DOMINION ELECTRIC	OS					4			
10	OVEC POWER SCHEDULING	OS					1,503,357			
11	PJM INTERCONNECTION	OS					10,518,832			
12	Wind Deferral	OS					0			
13	[(a)] Wells Fargo Securities, LLC	OS					0			
15	TOTAL						13,437,092	0	0	0

Line No.	COST/SETTLEMENT OF POWER			
	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
1		23,095,714		23,095,714
2		14,567,920		14,567,920
3		12,972,705		12,972,705
4		15,235,958		15,235,958
5		5,252,986		5,252,986
6		11,385,921		11,385,921
7		10,377,958		10,377,958
8	803	45,435		46,238
9		4,274		4,274
10	65,597,767	56,172,223		121,769,990
11	25,734	311,614,518		311,640,252
12		(5,021,183)		(5,021,183)
13		636,407		636,407
15	65,624,304	456,340,836		521,965,140

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Deferral to track incremental costs related to approved RPS program, PER Virginia State Corporation Commission in APCo's RPS-RAC Case No. PUE-2020-00015.

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatt Hours Received (i)	TRANSFER OF ENERGY Megawatt Hours Delivered (j)
1	PJM Network Integ Rev - Affil	Various	Various	FNO	PJM OATT [(a)]	Various	Various			
2	PJM Network Integ Trans Rev Whlsle	Various	Various	FNO	PJM OATT	Various	Various			
3	PJM Network Integ Trans Serv	Various	Various	FNO	PJM OATT	Various	Various			
4	PJM Point to Point Trans Service	Various	Various	LFP	PJM OATT	Various	Various			
5	PJM Power Factor Credits Rev Nonaffiliated	Various	Various	OS	PJM OATT	Various	Various			
6	PJM Power Factor Credits Rev Whlsle	Various	Various	OS	PJM OATT	Various	Various			
7	PJM Trans Distribution & Metering	Various	Various	OS	PJM OATT	Various	Various			
8	PJM Trans Enhancement Rev	Various	Various	FNO	PJM OATT	Various	Various			
9	PJM Trans Enhancement Rev - Affil	Various	Various	FNO	PJM OATT	Various	Various			
10	PJM Trans Enhancement Rev Whlsle	Various	Various	FNO	PJM OATT	Various	Various			
11	PJM Trans Owner Admin Rev - Affil	Various	Various	OLF	PJM OATT	Various	Various			
12	PJM Trans Owner Admin Revenue	Various	Various	OLF	PJM OATT	Various	Various			
13	PJM Trans Owner Serv Rev Whlsle	Various	Various	OLF	PJM OATT	Various	Various			
35	TOTAL									

Line No.	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	100,108,946			100,108,946
2	14,176,547			14,176,547
3	59,314,812			59,314,812
4	5,771,350			5,771,350
5			225,806	225,806
6			83,661	83,661
7			108,975	108,975
8	10,401,729			10,401,729
9	357,955			357,955
10	284,922			284,922
11		1,364,115		1,364,115
12		1,116,092		1,116,092
13		66,593		66,593
35	190,416,261	2,546,800	418,442	193,381,503

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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.

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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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42					
43					

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
44					
45					
46					
47					
48					
49					
40	TOTAL				
Page 331					

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	PJM - Enhancements	OS					[a]36,817,446	36,817,446
2	PJM - Trans Owner Serv	OS					[b](231,807)	(231,807)
3	PJM - NITS	OS					[c]341,541,268	341,541,268
	TOTAL						378,126,908	378,126,908

FOOTNOTE DATA

(a) Concept: OtherChargesTransmissionOfElectricityByOthers
Transmission Enhancement Charges and Credits (PJM OATT Schedule 12)
(b) Concept: OtherChargesTransmissionOfElectricityByOthers
Network Integration Transmission Service Charges - NITS (PJM OATT Attachment H)
(c) Concept: OtherChargesTransmissionOfElectricityByOthers
Transmission Owner Charges and Credits (PJM OATT Tariff Sixth Revised Volume No. 1.)

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	544,585
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	16,282
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Associated Business Development	9,214,275
7	Affiliated Intercompany Billings	630,318
8	Broadband Study	15,431
9	Corporate Contributions and Memberships	123,736
10	Various Chambers of Commerce	42,370
11	Trustee Fees	68,080
12	Utility Corp Borrowing Program Shared Costs	111,367
13	Various Expenses	1,062
46	TOTAL	10,767,506

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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			48,894,435		48,894,435
2	Steam Production Plant	188,714,711	5,502,727			194,217,438
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	5,223,655	30,476			5,254,131
5	Hydraulic Production Plant-Pumped Storage	5,181,704	45,648			5,227,352
6	Other Production Plant	16,074,319	326			16,074,645
7	Transmission Plant	102,977,731				102,977,731
8	Distribution Plant	177,353,891	69			177,353,960
9	Regional Transmission and Market Operation					
10	General Plant	17,825,532	43,330	117,711		17,986,573
11	Common Plant-Electric					
12	TOTAL	513,351,543	5,622,576	49,012,146		567,986,265

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.
Section A Line 10, Column D represents amortization of leasehold improvements over the lives of the related assets.

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						
13	311 - Amos CCR/ELG	78,839	69 years	9%	3.91%		
14	311 - Amos U1&2	58,350	69 years	9%	2.62%		
15	311 - Amos U3	146,906	67 years	9%	2.57%		
16	311 - Central Plt Maint	86	0 years		2%		
17	311 - Clinch River	27,099	67 years	10%	4.26%		
18	311 - Little Broad Mtn	267	0 years		3.59%		
19	311 - Mountaineer	193,816	60 years	10%	3.4%		
20	311 - Mountaineer CCR/ELG	63,224	60 years	10%	4.55%		
21	312 - Amos U1&2	1,405,794	69 years	9%	3.14%		
22	312 - Amos U1&2 SCR	20,163	69 years	9%	5.14%		
23	312 - Amos U3	1,591,498	67 years	9%	3.35%		
24	312 - Amos U3 SCR	18,634	67 years	9%	6.26%		
25	312 - Clinch River	215,975	67 years	10%	5.83%		
26	312 - Little Broad Mtn	50,334	0 years		3.61%		
27	312 - Mountaineer	1,163,615	60 years	10%	3.24%		
28	312 - Mountaineer SCR	18,740	60 years	10%	6.81%		
29	314 - Amos U1&2	128,121	69 years	9%	3.49%		
30	314 - Amos U3	162,742	67 years	9%	3.56%		
31	314 - Clinch River	40,605	67 years	10%	3.36%		
32	314 - Mountaineer	131,733	60 years	10%	3.31%		
33	315 - Amos U1&2	58,351	69 years	9%	3.15%		
34	315 - Amos U3	38,202	67 years	9%	2.55%		
35	315 - Clinch River	11,184	67 years	10%	3.55%		
36	315 - Little Broad Mtn	65	0 years		3.72%		
37	315 - Mountaineer	76,715	60 years	10%	2.07%		
38	316 - Amos U1&2	11,541	69 years	9%	4.18%		
39	316 - Amos U3	39,554	67 years	9%	2.98%		
40	316 - Centrl Mach Shop	23,190	0 years		2.8%		
41	316 - Clinch River	6,469	67 years	10%	5.83%		
42	316 - Mountaineer	26,391	60 years	10%	2.82%		
43	TOTAL STEAM	5,808,203					
44	HYDRO						
45	331 - Buck Hydro	893	162 years	34%	3.61%		
46	331 - Byllesby Hydro	1,655	162 years	34%	5.06%		
47	331 - Claytor Hydro	4,361	102 years	34%	3.97%		
48	331 - Leesville Hydro	4,285	76 years	34%	3.06%		
49	331 - London Hydro	1,003	129 years	34%	2.84%		
50	331 - Marmet Hydro	2,376	129 years	34%	2.6%		
51	331 - Niagara Hydro	721	158 years	34%	6.79%		
52	331 - Winfield Hydro	3,508	126 years	34%	3.11%		
53	332 - Buck Hydro	7,896	162 years	34%	4.55%		
54	332 - Byllesby Hydro	7,470	162 years	34%	5.45%		
55	332 - Claytor Hydro	13,114	102 years	34%	2.47%		
56	332 - Leesville Hydro	12,302	76 years	34%	2.67%		
57	332 - London Hydro	2,288	129 years	34%	2.29%		
58	332 - Marmet Hydro	3,291	129 years	34%	2.59%		
59	332 - Niagara Hydro	7,063	158 years	34%	4.76%		
60	332 - Winfield Hydro	2,931	126 years	34%	2.54%		
61	333 - Buck Hydro	2,053	162 years	34%	2.68%		
62	333 - Byllesby Hydro	3,702	162 years	34%	5.35%		
63	333 - Claytor Hydro	4,898	102 years	34%	3.68%		
64	333 - Leesville Hydro	3,764	76 years	34%	2.29%		

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)
65	333 - London Hydro	12,408	129 years	34%	3.39%		
66	333 - Marmet Hydro	11,312	129 years	34%	3.62%		
67	333 - Niagara Hydro	640	158 years	34%	2.24%		
68	333 - Winfield Hydro	8,136	126 years	34%	3.43%		
69	334 - Buck Hydro	2,547	162 years	34%	3.44%		
70	334 - Byllesby Hydro	1,137	162 years	34%	4.03%		
71	334 - Claytor Hydro	3,333	102 years	34%	3.03%		
72	334 - Leesville Hydro	2,300	76 years	34%	4.61%		
73	334 - London Hydro	1,973	129 years	34%	2.33%		
74	334 - Marmet Hydro	2,252	129 years	34%	2.35%		
75	334 - Niagara Hydro	532	158 years	34%	6.53%		
76	334 - Winfield Hydro	330	126 years	34%	3.31%		
77	335 - Buck Hydro	1,000	162 years	34%	5.79%		
78	335 - Byllesby Hydro	1,325	162 years	34%	5.02%		
79	335 - Claytor Hydro	3,318	102 years	34%	3.6%		
80	335 - Leesville Hydro	3,525	76 years	34%	4.21%		
81	335 - London Hydro	1,078	129 years	34%	2.98%		
82	335 - Marmet Hydro	1,329	129 years	34%	2.74%		
83	335 - Niagara Hydro	489	158 years	34%	3.17%		
84	335 - Winfield Hydro	3,644	126 years	34%	2.19%		
85	336 - Buck Hydro	3	162 years	34%	2.23%		
86	336 - Claytor Hydro	32	102 years	34%	1.25%		
87	336 - Leesville Hydro	81	76 years	34%	1.28%		
88	336 - London Hydro	49	129 years	34%	1.3%		
89	336 - Marmet Hydro	1	129 years	34%	1.27%		
90	336 - Winfield Hydro	24	126 years	34%	2.21%		
91	TOTAL HYDRO	152,372					
92	HYDRO PUMPED						
93	331	17,037	75 years	34%	2.49%		
94	332	33,112	75 years	34%	2.3%		
95	333	78,826	75 years	34%	3.71%		
96	334	13,414	75 years	34%	4.42%		
97	335	11,904	75 years	34%	4.05%		
98	336	1,052	75 years	34%	1.34%		
99	TOTAL HYDRO PUMPED	155,345					
100	OTHER GENERATION						
101	341 Ceredo Plant	1,747	40 years		1.32%		
102	341 Dresden Plant	49,822	35 years	1%	3.43%		
103	341 Dresden - VA AFUDC	1,628	0 years				
104	342 Dresden Plant	26,209	35 years	1%	3.07%		
105	342 Dresden - VA AFUDC	814	0 years				
106	344 Amherst Solar	11,603	0 years		2.86%		
107	344 Ceredo Plant	182,620	40 years		1.34%		
108	344 Dresden Plant	325,290	35 years	1%	3.14%		
109	344 Dresden - VA AFUDC	11,234	0 years				
110	345 Ceredo Plant	20,017	40 years		1.48%		
111	345 Dresden Plant	28,034	35 years	1%	3.26%		
112	345 Dresden - VA AFUDC	814	0 years				
113	346 Ceredo Plant	1,683	40 years		4.55%		
114	346 Dresden Plant	31,997	35 years	1%	4.38%		
115	346 Dresden - VA AFUDC	163	0 years				
116	348 Battery Storage	5,726	0 years		4.98%		
117	TOTAL OTHER	699,401					

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)
118	TRANSMISSION						
119	350 - VA (Rights)	101,293	0 years		0.66%		
120	352	188,216	59 years	28%	1.97%	L3	
121	353	2,105,514	43 years	12%	2.55%	R2	
122	353 Dresden Plant - VA AFUDC	713	0 years				
123	353.16	21,538	43 years	12%	2.55%	R2	
124	354	517,520	78 years	22%	1.66%	R4	
125	355	613,920	35 years	21%	3.17%	L1.5	
126	356	827,894	69 years	28%	1.82%	R4	
127	356.16	58,682	69 years	28%	1.82%	R3.5	
128	357	20,828	42 years		2.9%	S6	
129	358	19,984	24 years		4.65%	L3.5	
130	358.16	8,695	24 years		4.65%	L3.5	
131	TOTAL TRANSMISSION	4,484,797					
132	DISTRIBUTION						
133	360 - VA (Rights)	25,745	0 years		1.49%		
134	361 - VA	51,094	50 years		2.53%	R5	
135	361 - WV	30,248	55 years		1.9%	R3	
136	361-373 - TN	47	0 years		4%		
137	362 - VA	449,829	50 years	25%	2.48%	L0.5	
138	362 - WV	302,116	45 years	16%	2.52%	R1	
139	362.16 - VA	9,345	50 years	25%	2.48%	L0.5	
140	362.16 - WV	6,899	45 years	16%	2.52%	R1	
141	363 - WV	165	15 years		7.38%	SQ	
142	364 - VA	476,833	44 years	81%	3.5%	R0.5	
143	364 - WV	510,483	33 years	67%	4.77%	R0.5	
144	365 - VA	682,332	40 years	24%	3.24%	R1	
145	365 - WV	642,445	35 years	16%	3.38%	R0.5	
146	366 - VA	87,413	60 years		1.57%	R4	
147	366 - WV	67,904	55 years		1.73%	R4	
148	367 - VA	224,115	55 years		1.68%	R2.5	
149	367 - WV	123,168	48 years		2.05%	R1.5	
150	368 - VA	447,296	37 years	21%	2.97%	L0.5	
151	368 - WV	256,242	27 years	20%	4.65%	R0.5	
152	369 - VA	211,741	38 years	31%	3.19%	L1.5	
153	369 - WV	191,451	30 years	26%	4.22%	R0.5	
154	370 - VA	16,238	15 years	6%	8.42%	L1	
155	370 - WV	27,065	15 years	10%	12.43%	S6	
156	370.16 - VA	99,746	15 years	6%	8.42%	L1	
157	370.16 - WA	68,462	15 years	10%	12.43%	S6	
158	371 - VA	44,354	16 years	29%	6.12%	L0	
159	371 - WV	26,632	12 years	22%	9.3%	R0.5	
160	372 - VA	1	35 years		0.78%	L3	
161	373 - VA	23,157	23 years	37%	5%	R0.5	
162	373 - WV	12.544	20 years	31%	8.17%	R0.5	
163	TOTAL DISTRIBUTION	5,115,110					
164	GENERAL PLANT						
165	390	254,433	46 years	(3)%	2.07%	R2.5	
166	391	15,915	30 years		3.23%	SQ	
167	392	9	27 years		3.44%	SQ	
168	393	3,681	55 years		1.88%	SQ	
169	394	51,662	43 years	10%	2.63%	SQ	
170	395	2,334	37 years		3.72%	SQ	

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)
171	396	114	25 years		4.02%	SQ	
172	397	164,625	24 years	15%	4.93%	SQ	
173	397.12	41	24 years	15%	4.93%	SQ	
174	397.16	59,333	24 years	15%	4.93%	SQ	
175	398	11,666	35 years		2.75%	SQ	
176	TOTAL GENERAL PLANT	563,813					
177	DEPRECIABLE SUM	[a]16,979,041					

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DepreciablePlantBase
The depreciable plant base is the November 30, 2023 total company depreciable plant.

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	Smith Mountain Combination Project #2210 - Proportion of cost of administering the Federal Water Power Act	1,617,244		1,617,244			928	1,617,244				
2	Leesville Hydro Project #2210 - Proportion of cost of administering the Federal Water Power Act	106,704		106,704			928	106,704				
3	Claytor Hydro Project #739 - Proportion of cost of administering the Federal Water Power Act	234,702		234,702			928	234,702				
4	Byllesby Buck Hydro Project #2514 - Proportion of cost of administering the Federal Water Power Act	99,054		99,054			928	99,054				
5	Marmet and London Hydro Project #1175 - Proportion of cost of administering the Federal Water Power Act	98,929		98,929			928	98,929				
6	Winfield Hydro Project #1290 - Proportion of cost of administering the Federal Water Power Act	75,319		75,319			928	75,319				
7	Niagara Hydro Project #2466 - Proportion of cost of administering the Federal Water Power Act	7,717		7,717			928	7,717				
8	Misc Exp - items less than $25,000		158,792	158,792			928	158,792				
9	West Virginia Base Case		72,809	72,809			928	72,809				
10	Virginia Broadband Filing		124,733	124,733			928	124,733				
11	Virginia Fuel Factor Filing		137,201	137,201			928	137,201				
12	Virginia Generation RAC Filing		67,810	67,810			928	67,810				
13	Virginia Energy Efficiency RAC filing		79,021	79,021			928	79,021				
14	Virginia Triennial Filing		1,181,121	1,181,121			928	1,181,121	546,487			546,487
15	Virginia Transportation Electrification Filing		31,684	31,684			928	31,684				
16	Virginia Blue Ridge Petition Filing		141,305	141,305			928	141,305				
17	Virginia Transmission RAC Filing		32,401	32,401			928	32,401				
18	State Commission Fees		4,580,983	4,580,983			928	4,580,983				
19	Virginia Clean Economy Act Filing		548,721	548,721			928	548,721				
20	FERC Formula Rate Filing		117,485	117,485			928	117,485				
21	West Virginia ENEC Filing		265,479	265,479			928	265,479				
22	West Virginia Regulatory and Legislative Activities		55,848	55,848			928	55,848				
23	Virginia Biennial Filing		50,976	50,976			928	50,976				
24	Virginia Environmental RAC Filing		28,602	28,602			928	28,602				

						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)
46	TOTAL	2,239,669	7,674,971	9,914,640				9,914,640	546,487			546,487

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

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	ELECTRIC UTILITY RESEARCH, DEVELOPMENT &						
2	DEMONSTRATION PERFORMED INTERNALLY						
3	A(1)b Generation: Fossil - Fuel Steam	Adv. Generation Prog. Management	101,634		506	101,634	
4		2 Item(s) Under $50,000	23,581		506	23,581	
5	A(1)e CEATI (Centre for Energy Advancement through Technological Innovation) Membership	1 Item(s) Under $50,000	684		506	684	
6	A(2) Transmission:	1 Item(s) Under $50,000	7,835		566	7,835	
7	A(3) Distribution:	1 Item(s) Under $50,000	12,725		588	12,725	
8	A(5) Environment: (Other Than Equipment)	2 Item(s) Under $50,000	668		506	668	
9	A(6) Other:	Corporate Technology Prog Mgmt	783		506,566,588	783	
10		1 Item(s) Under $50,000	(579)		506,566,588	(579)	
11	A(6)a:						
12	A(6)f Other: Metering	1 Item(s) Under $50,000	2,025		588	2,025	
13	A(6)g Research - General:	1 Item(s) Under $50,000	2,315		566, 588	2,315	
14	A(7) TOTAL COST INCURRED INTERNALLY		151,671			151,671	
15	ELECTRIC UTILITY RESEARCH, DEVELOPMENT & DEMONSTRATION PERFORMED EXTERNALLY	4 Item(s) Under $50,000		71,656	506,566,588	71,656	
16	B(1) Research Support to Elec. Research Council & Elec. Power Research Inst.	EPRI Research Portfolio		1,287,230	506,566,588	1,287,230	
17		EPRI Environmental Science		835,382	506	835,382	
18		Decarbonized Future		51,470	506	51,470	
19		Low Carbon Resource Initiative		496,403	506,566,588	496,403	

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
20		IT - EPRI Annual Research Port		61,781	506,566,588	61,781	
21		22 Item(s) Under $50,000		98,605	506,566,588	98,605	
22	B(4) Research Support to Others	2 Item(s) under $50,000		444	506,566	444	
23	B(5) TOTAL COST INCURRED EXTERNALLY			2,902,971		2,902,971	
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Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	27,692,200		
4	Transmission	69,721		
5	Regional Market			
6	Distribution	12,375,678		
7	Customer Accounts	5,711,367		
8	Customer Service and Informational	2,666,134		
9	Sales			
10	Administrative and General	1,662,082		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	50,177,182		
12	Maintenance			
13	Production	24,477,279		
14	Transmission	70,733		
15	Regional Market			
16	Distribution	29,851,510		
17	Administrative and General	2,378,368		
18	TOTAL Maintenance (Total of lines 13 thru 17)	56,777,890		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	52,169,479		
21	Transmission (Enter Total of lines 4 and 14)	140,454		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	42,227,188		
24	Customer Accounts (Transcribe from line 7)	5,711,367		
25	Customer Service and Informational (Transcribe from line 8)	2,666,134		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	4,040,450		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	106,955,072	7,526,675	114,481,747
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)	106,955,072	7,526,675	114,481,747
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	57,393,097	4,038,885	61,431,982
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	57,393,097	4,038,885	61,431,982
72	Plant Removal (By Utility Departments)			
73	Electric Plant	11,794,648	830,017	12,624,665
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	11,794,648	830,017	12,624,665
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	152 - Fuel Stock Undistributed	8,237,069		8,237,069
80	154 - Materials and Supplies			
81	163 - Stores Expense Undistributed	6,259,829	(6,259,829)	
82	165 - Other Prepayments			
83	182 - Other Regulatory Assets			
84	183 - Prelim Survey	7,943	(7,943)	
85	184 - Clearing Accounts	6,127,805	(6,127,805)	
86	185 - ODD Temporary Facilities	220,156		220,156
87	186 - Misc Deferred Debits	1,263,198		1,263,198
88	188 - Research & Development			
89	228 - RAD Waste Accrual			
90	242 - Misc Current & Accrued Liab			
91	418 - Nonoperating Rental Income			
92	421 - Misc Nonoperating Income			
93	426 - Political Activities	465,703		465,703
94	451 - Misc Service Rev - Nonaffil			
95	456 - Other Electric Revenue			
95	TOTAL Other Accounts	22,581,703	(12,395,577)	10,186,126
96	TOTAL SALARIES AND WAGES	198,724,520		198,724,520

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Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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.

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)	81,206,205	150,139,064	202,217,568	300,360,778
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(20,259,747)	(33,434,970)	(64,966,800)	(76,219,714)
4	Transmission Rights	(9,038,844)	(27,631,102)	(33,545,562)	(37,924,424)
5	Ancillary Services	3,525,786	4,500,349	4,234,147	4,999,998
6	Other Items (list separately)				
7	Congestion	8,079,839	17,716,449	24,801,909	32,234,801
8	Operating Reserves	(783,914)	(1,459,686)	(1,238,952)	(1,276,248)
9	Transmission Purchase Expense	6,678,708	13,806,153	20,544,871	26,497,883
10	Transmission Losses	2,174,865	3,806,588	6,895,566	9,184,198
11	Meter Corrections	(724,861)	(709,244)	(1,268,083)	(1,322,085)
12	Inadvertent	(83,744)	(47,508)	69,091	116,514
13	Capacity Credits	(1,799,191)	(3,349,175)	(4,595,591)	(5,771,850)
46	TOTAL	68,975,102	123,336,918	153,148,164	250,879,851

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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

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Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: MonthlyPeakLoadExcludingIsoAndRto
Appalachian 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: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2024-04-09	Year/Period of Report End of: 2023/ 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)	25,367,677
3	Steam	13,480,005	23	Requirements Sales for Resale (See instruction 4, page 311.)	3,013,780
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,093,827
5	Hydro-Conventional	577,214	25	Energy Furnished Without Charge	[a](318,641)
6	Hydro-Pumped Storage	451,702	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other	4,614,962	27	Total Energy Losses	1,863,095
8	Less Energy for Pumping	541,237	27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	18,582,646	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	32,019,738
10	Purchases (other than for Energy Storage)	13,437,092			
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)	32,019,738			

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2024-04-09	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: NonChargedEnergy

Represents Megawatt Hours included in Line 22, Sales to Ultimate Consumers, that were delivered and billed to shopping customers and provided by external suppliers. This total also includes hydropower Megawatt Hours provided free of charge to the Government.

Sales to Ultimate Consumers	(343,073)
Hydropower to Government	879
	(342,194)

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	3,063,219	146,891	5,494	15	9
30	February	2,591,998	149,171	5,865	4	8
31	March	2,864,383	265,135	5,923	20	8
32	April	2,229,993	63,408	4,166	10	8
33	May	2,307,964	95,673	3,945	11	18
34	June	2,625,623	311,618	4,562	30	18
35	July	3,058,012	373,926	5,269	28	15
36	August	2,904,369	253,208	5,105	22	17
37	September	2,447,217	90,424	5,173	6	18
38	October	2,293,549	88,667	4,071	4	17
39	November	2,667,527	131,141	6,004	29	8
40	December	2,965,884	224,504	5,923	20	8
41	Total	32,019,738	2,193,766			

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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: Amos	Plant Name: Ceredo	Plant Name: Clinch River	Plant Name: Dresden	Plant Name: Mountaineer
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		STEAM	GAS TURBINE	STEAM	COMBINED CYCLE	STEAM
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		CONVENTIONAL	NO BOILER	CONVENTIONAL	OUTDOOR HRSG	OUTDOOR BOILER
3	Year Originally Constructed		1971	2001	1958	2012	1980
4	Year Last Unit was Installed		1973	2001	1961	2012	1980
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)		2,963.00	519.18	712.50	669.00	1,320.00
6	Net Peak Demand on Plant - MW (60 minutes)		2,834	549	337	663	1,322
7	Plant Hours Connected to Load		5,894	1,134	577	7,476	6,219
8	Net Continuous Plant Capability (Megawatts)		0	0	0	0	0
9	When Not Limited by Condenser Water		2,930	516	465	665	1,320
10	When Limited by Condenser Water		2,930	450	455	570	1,305
11	Average Number of Employees		234	7	34	32	147
12	Net Generation, Exclusive of Plant Use - kWh		8,424,839,000	469,800,000	85,761,000	4,145,161,000	4,969,405,000
13	Cost of Plant: Land and Land Rights		7,307,834	910,000	501,098	2,286,932	4,554,535
14	Structures and Improvements		285,905,587	1,747,156	27,098,637	51,712,828	257,726,306
15	Equipment Costs		3,475,778,586	204,319,621	274,246,967	424,961,099	1,467,766,302
16	Asset Retirement Costs		122,863,099	0	4,831,339	0	17,129,405
17	Total cost (total 13 thru 20)		3,891,855,106	206,976,776	306,678,042	478,960,859	1,747,176,548
18	Cost per KW of Installed Capacity (line 17/5) Including		1,313.4847	398.6609	430.4253	715.9355	1,323.6186
19	Production Expenses: Oper, Supv, & Engr		11,559,218	150,706	997,111	534,109	4,829,959
20	Fuel		335,431,990	10,515,328	[(a)]8,522,163	67,663,769	178,964,053
21	Coolants and Water (Nuclear Plants Only)		0	0	0	0	0
22	Steam Expenses		29,193,571	99,437	3,514,106	511,491	12,092,882
23	Steam From Other Sources		0	0	0	0	0
24	Steam Transferred (Cr)		0	0	0	0	0
25	Electric Expenses		132,037	612,472	0	0	0
26	Misc Steam (or Nuclear) Power Expenses		6,500,571	267,079	1,901,948	5,681,386	8,308,121
27	Rents		34,614	1,577	0	0	15,341
28	Allowances		158,372	0	1,161,567	294	103,053
29	Maintenance Supervision and Engineering		2,680,216	1,218	7,749	102,672	191,250
30	Maintenance of Structures		2,920,425	0	436,831	1,139,756	1,678,843
31	Maintenance of Boiler (or reactor) Plant		31,620,227	3,567	2,666,994	877,635	13,921,238
32	Maintenance of Electric Plant		11,649,426	685,548	500,380	2,619,905	3,185,279
33	Maintenance of Misc Steam (or Nuclear) Plant		6,481,745	0	820,945	2,517,841	2,698,301
34	Total Production Expenses	0	438,362,412	12,336,932	20,529,794	81,648,858	225,988,320
35	Expenses per Net kWh		0.0520	0.0263	0.2394	0.0197	0.0455

35	**Plant Name**	Amos	Amos	Ceredo	Clinch River	Dresden	Mountaineer	Mountaineer
36	Fuel Kind	Coal	Oil	Gas	Gas	Gas	Coal	Oil
37	Fuel Unit	T	bbl	Mcf	Mcf	Mcf	T	bbl
38	Quantity (Units) of Fuel Burned	3,533,572	124,230	5,463,798	1,113,569	26,736,181	2,047,738	32,009
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12,466	138,940	1,056,000	1,025,000	1,065,000	12,281	138,157
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	88.176	131.052	1.802	7.557	2.511	76.820	140.329
41	Average Cost of Fuel per Unit Burned	79.747	137.281	1.889	7.644	2.513	76.788	133.298
42	Average Cost of Fuel Burned per Million BTU	3.199	23.525	1.789	7.458	2.359	3.126	22.972
43	Average Cost of Fuel Burned per kWh Net Gen	0.033	0.000	0.022	0.099	0.016	0.032	0.000
44	Average BTU per kWh Net Generation	10,328.000	0.000	13,420.000	12,759.000	10,727.000	10,063.000	0.000

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: FuelSteamPowerGeneration
Deferred Fuel expenses totaling $306,308,060 are not included in the Fuel totals that are broken down by generating plants. Deferred fuel expenses for Virginia and West Virginia were $153,463,324 and $152,844,736, respectively.

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	FERC Licensed Project No. 0 Plant Name: BUCK	FERC Licensed Project No. 0 Plant Name: BYLLESBY	FERC Licensed Project No. 0 Plant Name: CLAYTOR	FERC Licensed Project No. 0 Plant Name: LEESVILLE	FERC Licensed Project No. 0 Plant Name: LONDON	FERC Licensed Project No. 0 Plant Name: MARMET	FERC Licensed Project No. 0 Plant Name: WINFIELD
1	Kind of Plant (Run-of-River or Storage)		STORAGE	STORAGE	STORAGE	STORAGE	RUN OF RIVER	RUN OF RIVER	RUN OF RIVER
2	Plant Construction type (Conventional or Outdoor)		CONVENTIONAL	CONVENTIONAL	CONVENTIONAL	OUTDOOR	CONVENTIONAL	CONVENTIONAL	CONVENTIONAL
3	Year Originally Constructed		1912	1912	1939	1964	1935	1935	1938
4	Year Last Unit was Installed		1912	1912	1939	1964	1935	1935	1938
5	Total installed cap (Gen name plate Rating in MW)		10.7	21.6	75.0	40.0	14.4	14.4	14.8
6	Net Peak Demand on Plant-Megawatts (60 minutes)		10	15	79	50	18	17	22
7	Plant Hours Connect to Load		8,065	7,849	6,693	1,411	7,479	4,623	7,274
8	**Net Plant Capability (in megawatts)**								
9	(a) Under Most Favorable Oper Conditions		11	23	88	48	19	20	24
10	(b) Under the Most Adverse Oper Conditions								
11	Average Number of Employees			3	4	1	1	4	4
12	Net Generation, Exclusive of Plant Use - kWh		38,370,000	51,943,000	197,823,000	46,721,000	65,155,000	58,662,000	110,540,000
13	**Cost of Plant**								
14	Land and Land Rights			170,420	1,612,350	1,784,759	21,043	4,100	
15	Structures and Improvements		892,997	1,654,593	4,360,505	4,284,874	1,003,301	2,375,771	3,508,385
16	Reservoirs, Dams, and Waterways		7,895,918	7,469,565	14,225,861	12,301,570	2,288,034	3,290,578	2,931,197
17	Equipment Costs		5,599,978	[a]11,890,555	11,547,847	9,603,521	15,459,037	14,893,835	12,110,628
18	Roads, Railroads, and Bridges		3,437		31,799	80,790	48,853	1,275	23,567
19	Asset Retirement Costs			72,046	362,724	196,310	93,690	125,314	137,743
20	Total cost (total 13 thru 20)		14,392,330.00	21,257,179	32,141,086	28,251,824	18,913,958	20,690,873.00	18,711,520
21	Cost per KW of Installed Capacity (line 20 / 5)		1,345.1	984.1287	428.5478	706.2956	1,313.4693	1,436.9	1,264.2919
22	**Production Expenses**								
23	Operation Supervision and Engineering		55,607	69,501	257,337	78,833	85,259	165,151	243,789
24	Water for Power		6,794	112	3,368		7,882	7,882	7,882
25	Hydraulic Expenses		5,816	8,887	(195,669)	85,715	11,227	13,182	17,284
26	Electric Expenses		63,266	8,065	29,988	7,083	9,877	8,893	16,765
27	Misc Hydraulic Power Generation Expenses			133,425	631,232	82,520	309,858	545,868	299,954
28	Rents						90,437	90,437	166,012

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0	FERC Licensed Project No. 0 Plant Name: BUCK	FERC Licensed Project No. 0 Plant Name: BYLLESBY	FERC Licensed Project No. 0 Plant Name: CLAYTOR	FERC Licensed Project No. 0 Plant Name: LEESVILLE	FERC Licensed Project No. 0 Plant Name: LONDON	FERC Licensed Project No. 0 Plant Name: MARMET	FERC Licensed Project No. 0 Plant Name: WINFIELD
29	Maintenance Supervision and Engineering		402	545	2,074	490	4,428	18,162	1,159
30	Maintenance of Structures		86,883	100,710	496,178	1,014,250	125,935	123,194	56,088
31	Maintenance of Reservoirs, Dams, and Waterways		65,530	168,820	21,507	541,723	78,253	430,383	148,319
32	Maintenance of Electric Plant		41,121	151,555	214,411	102,083	457,585	750,247	86,371
33	Maintenance of Misc Hydraulic Plant		1,751	415	2,918	111,750	14,457	13,901	9,127
34	Total Production Expenses (total 23 thru 33)		327,170	642,035	1,463,344	2,024,447	1,195,198	2,167,300	1,052,750
35	Expenses per net kWh		0.0085	0.0124	0.0074	0.0433	0.0183	0.0369	0.0095

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Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: EquipmentCostsHydroelectricProduction
Equipment cost amount also includes $5,726,248.80 of battery storage investment in account 34800.

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	FERC Licensed Project No. 0 Plant Name: SMITH MOUNTAIN
1	Type of Plant Construction (Conventional or Outdoor)		OUTDOOR
2	Year Originally Constructed		1965
3	Year Last Unit was Installed		1980
4	Total installed cap (Gen name plate Rating in MW)		647
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	0	595
6	Plant Hours Connect to Load While Generating	0	931
7	Net Plant Capability (in megawatts)	0	565
8	Average Number of Employees		18
9	Generation, Exclusive of Plant Use - kWh	0	451,702,000
10	Energy Used for Pumping		541,236,000
11	Net Output for Load (line 9 - line 10) - Kwh	0	(89,534,000)
12	**Cost of Plant**		
13	Land and Land Rights		6,168,815
14	Structures and Improvements	0	17,036,771
15	Reservoirs, Dams, and Waterways	0	33,112,077
16	Water Wheels, Turbines, and Generators	0	78,825,579
17	Accessory Electric Equipment	0	13,413,621
18	Miscellaneous Powerplant Equipment	0	12,096,674
19	Roads, Railroads, and Bridges	0	1,052,133
20	Asset Retirement Costs	0	1,687,175
21	Total cost (total 13 thru 20)		163,392,845
22	Cost per KW of installed cap (line 21 / 4)		252.5392
23	**Production Expenses**		
24	Operation Supervision and Engineering	0	697,916
25	Water for Power	0	
26	Pumped Storage Expenses	0	301,859
27	Electric Expenses	0	68,475
28	Misc Pumped Storage Power generation Expenses	0	1,794,246
29	Rents	0	
30	Maintenance Supervision and Engineering	0	159,833
31	Maintenance of Structures	0	1,338,589
32	Maintenance of Reservoirs, Dams, and Waterways	0	872,147
33	Maintenance of Electric Plant	0	1,879,887
34	Maintenance of Misc Pumped Storage Plant	0	82,021
35	Production Exp Before Pumping Exp (24 thru 34)		7,194,973
36	Pumping Expenses		11,941,564
37	Total Production Exp (total 35 and 36)		19,136,537
38	Expenses per kWh (line 37 / 9)		0.0424
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))		

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Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
1	HYDRO-ELECTRIC												
2	Niagara - Project #2466	1906	3.60	2.4	8,001,000	9,807,165		43,929		335,158			
3	Solar electric												
4	Amherst	2023	5.00			11,676,704		14,581		22,819			
5	TOTAL (Small Plants)				8,001,000	21,483,869							

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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 Pow (Dolla (o)
35	TOTAL			0	0	0	0	0	0	0	0	0	0	0	

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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								

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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 From (a)	To (b)	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designated (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)	Size of Conductor and Material (i)
1	STATE OF TENNESSEE	STATE OF TENNESSEE							
2	0188 BRADFORD, VA	SULLIVAN, TN	500	500	3	0.00	0.00	1	2049KCM ACAR
3	0400 CANE RIVER, TN CIR-A	NAGEL, TN	230	230	3	46.00	0.00	1	1590KCM ACSR
4	0400 CANE RIVER, TN CIR-B	NAGEL, TN	230	230	3	1.00	45.00	1	1590KCM ACSR
5	0351 CLINCH RIVER, VA	NAGEL, TN	138	138	3	0.00	0.00	1	1590KCM ACSR
6	0353 NAGEL, TN	REEDY CREEK, TN	138	138	3	0.00	0.00	1	1590KCM ACSR
7	0349 BROADFORD, VA	NAGEL, TN	138	138	3	13.00	0.00	1	397KCM ACSR
8	0349 BROADFORD, VA	NAGEL, TN	0	0	1	0.00	0.00	0	
9	0355 NAGEL, TN	WEST KINGSPORT, TN	138	138	3	0.00	1.00	1	556KCM
10	0355 NAGEL, TN	WEST KINGSPORT, TN	0	0	1	0.00	0.00	0	
11	0176 NORTH BRISTOL, VA	WEST KINGSPORT, VA	138	138	3	6.00	11.00	1	397KCM ACSR
12	0176A HOLSTON, TN	REEDY CREEK, TN	138	138	3	0.00	6.00	1	397KCM ACSR
13	0179 BOONE DAM, TN	HOLSTON, TN	138	138	3	0.00	0.00	1	636KCM ACSR
14	0179 BOONE DAM, TN	HOLSTON, TN	0	0	1	8.00	0.00	0	
15	0180 HOLSTON, TN	WALTERS, NC	138	138	3	65.00	0.00	1	250KCM CU
16	0180 HOLSTON, TN	WALTERS, NC	138	138	1	0.00	0.00	1	1033KCM ACSR
17	0570 SALTVILLE	KINGSPORT (TN)	138	138	3	17.00	0.00	2	397.5KCM ACSR
18	STATE OF VIRGINIA	STATE OF VIRGINIA				0.00	0.00		
19	0186 BAKER, KY	BROADFORD, VA	765	765	3	0.00	0.00	1	954KCM ACSR
20	0186 BAKER, KY	BROADFORD, VA	0	0	3	47.00	0.00	0	
21	0187 BROADFORD, VA	JACKSONS FERRY, VA	765	765	3	49.00	0.00	1	954KCM ACSR
22	0253 CLOVERDALE, VA	JACKSONS FERRY, VA	765	765	3	65.00	0.00	1	954KCM ACSR
23	0310 CLOVERDALE, VA	JOSHUA FALLS, VA	765	765	3	57.00	0.00	1	1351KCM ACSR
24	0406 JACKSON FERRY	WYOMING	765	765	3	57.00	0.00	1	795 KCM ACSR
25	0334 AXTON, VA	JACKSONS FERRY, VA	765	765	3	73.00	0.00	1	1351KCM ACSR
26	0181 BROADFORD, VA	SULLIVAN, TN	500	500	3	33.00	0.00	1	2049KCM ACAR
27	0001CLOVERDALE, VA	LEXINGTON, VA	500	500	3	36.00	0.00	1	2-1780KCM ACSS
28	0001 CLOVERDALE	LEXINGTON, VA	500	500	2	0.00	0.00	1	2-1780kcm ACSS
29	0182 JACKSONS FERRY, VA	MCGUIRE, NC	500	500	3	26.00	0.00	1	2049KCM ACAR
30	0008A KANAWHA, WV	MATT FUNK, VA	345	345	3	8.00	0.00	1	1563KCM ACAR
31	0008A KANAWHA, WV	MATT FUNK, VA	0	0	3	34.00	0.00	0	
32	0008 CLOVERDALE, VA	MATT FUNK, VA	345	345	3	0.00	8.00	1	954 KCM ACSR
33	0008 CLOVERDALE, VA	MATT FUNK, VA	0	0	3	19.00	0.00	0	
34	0142 EAST DANVILLE NO. 1,VA	ROXBORO, NC	230	230	3	8.00	0.00	1	1590KCM ACSR
35	0142 EAST DANVILLE NO. 2,VA	ROXBORO, NC	230	230	3	0.00	8.00	1	1590KCM ACSR
36	0025 GLEN LYN, VA	SOUTH PRINCETON, WV	138	138	3	0.00	0.00	1	1590KCM ACSR
37	0038 BRADLEY CIR-A, WV	GLEN LYN-HINTON, VA	138	138	3	0.00	4.00	1	556KCM ACSR
38	0042 SALTVILLE, VA	TAZEWELL, VA	138	138	3	21.00	0.00	1	1272KCM ACSR
39	0042 SALTVILLE, VA	TAZEWELL, VA	138	138	3	0.00	21.00	1	397KCM ACSR
40	0042 SALTVILLE, VA	TAZEWELL, VA	138	138	1	0.00	0.00	1	1033KCM ACSR
41	0054 GARDEN CREEK, VA	HALES BRANCH, VA	138	138	3	0.00	0.00	1	636KCM ACSR
42	0054 GARDEN CREEK, VA	HALES BRANCH, VA	0	0	1	7.00	0.00	0	
43	0058 GLEN LYN, VA	WYTHE, VA	138	138	3	29.00	0.00	1	556KCM ACSR

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44	0058 GLEN LYN, VA	WYTHE, VA	0	0		1.00	0.00	0	1590KCM ACSR
45	0058 GLEN LYN, VA	WYTHE, VA	138	138	3	1.00	29.00	1	556KCM ACSR
46	0061 ATKINS, VA	BROADFORD CIR A, VA	138	138	3	20.00	0.00	1	556KCM ACSR
47	0061 ATKINS, VA	BROADFORD CIR B, VA	138	138	3	0.00	16.00	1	556KCM ACSR
48	0061B RURAL RETREAT	LOOP, WV	138	138	3	0.00	0.00	1	795KCM ACSR
49	0063 ATKINS, VA	WYTHE CIR A, VA	138	138	3	22.00	0.00	1	1590KCM ACSR
50	0063 ATKINS, VA	WYTHE CIR B, VA	138	138	3	0.00	21.00	1	556KCM ACSR
51	0063 BROADFORD, VA	SALTVILLE NO.1A&1B, VA	138	138	3	4.00	4.00	2	795KCM ACSR
52	0063 BROADFORD, VA	SALTVILLE NO.1A&1B, VA	138	138	3	0.00	4.00	2	556KCM ACSR
53	0063 BROADFORD, VA	SALTVILLE NO.1A&1B, VA	138	138	1	0.00	0.00	2	795KCM ACSR
54	0106 CLAYTOR, VA	GLEN LYN #1, VA	138	138	3	26.00	0.00	1	397KCM ACSR
55	0106 CLAYTOR, VA	GLEN LYN #2, VA	138	138	3	0.00	26.00	1	397KCM ACSR
56	0109 MORGANS CUT LOOP, VA		138	138	3	0.00	0.00	1	397KCM ACSR
57	0110 CLAYTOR, VA	MATT FUNK, VA	138	138	3	30.00	0.00	1	397KCM ACSR
58	0110 CLAYTOR, VA	MATT FUNK, VA	138	138	3	0.00	0.00	1	556KCM ACSR
59	0110A FALLING BRANCH	LOOP	138	138	2	1.00	0.00	1	556.5 KCM 26/7 AC
60	0112 MATT FUNK, VA	ROANOKE, VA	138	138	3	13.00	5.00	1	397KCM ACSR
61	0113 CLAYTOR, VA	HANCOCK, VA	138	138	3	0.00	39.00	1	397KCM ACSR
62	0114 HANCOCK, VA	ROANOKE, VA	138	138	3	5.00	4.00	1	397KCM ACSR
63	0115 CELANESE, VA	MATT FUNK, VA	138	138	3	34.00	0.00	1	556KCM ACSR
64	0115 CELANESE, VA	MATT FUNK, VA	138	138	1	2.00	0.00	1	556KCM ACSR
65	0115 CELANESE, VA	MATT FUNK, VA	138	138	3	0.00	0.00	2	1033KCM ACSR
66	0116 CELANESE, VA	GLEN LYN, VA	138	138	3	4.00	0.00	1	556KCM ACSR
67	0116 CELANESE, VA	GLEN LYN, VA	0	0	1	4.00	0.00	0	
68	0117 HANCOCK, VA	MATT FUNK, VA	138	138	3	11.00	0.00	1	556KCM ACSR
69	0118 CLOVERDALE, VA	MATT FUNK, VA	138	138	3	0.00	21.00	1	636KCM ACSR
70	0119 CLOVERDALE, VA	GLEN LYN, VA	138	138	3	20.00	39.00	1	556KCM ACSR
71	0119 CLOVERDALE, VA	GLEN LYN, VA	138	138	1	0.00	0.00	1	556KCM ACSR
72	0119 CLOVERDALE, VA	GLEN LYN, VA	138	138	3	0.00	0.00	2	795KCM ACSR
73	0120 BEAVER CREEK, KY	CLINCH RIVER, VA	138	138	3	26.00	0.00	1	636KCM ACSR
74	0120 BEAVER CREEK, KY	CLINCH RIVER, VA	138	138	1	0.00	0.00	0	636KCM ACSR
75	0122 CLINCH RIVER, VA	FREMONT, VA	138	138	3	0.00	18.00	1	636KCM ACSR
76	0123 BEAVER CREEK, KY	FREMONT, VA	138	138	3	0.00	9.00	1	636KCM ACSR
77	0124 CLOVERDALE, VA	SMITH MOUNTAIN, VA	138	138	3	32.00	0.00	1	556KCM ACSR
78	0125 CLINCH RIVER, VA	MORELAND DRIVE, TN	138	138	3	49.00	0.00	1	636KCM ACSR
79	0129 PHILPOTT TAP, VA		138	138	1	0.00	0.00	1	4/0KCM ACSR
80	0132 ROANOKE	CAROLINA	138	138	1	9.00	0.00	0	
81	0132 ROANOKE	CAROLINA	138	138	3	44.00	57.00	1	795KCM ACSR
82	0135 AXTON, VA	DANVILLE #2, VA	138	138	3	0.71	0.00	2	1033KCM ACSR
83	0135 AXTON, VA	DANVILLE #2, VA	138	138	2	16.57	0.00	1	1033KCM ACSR
84	0135 AXTON, VA	DANVILLE #2, VA	138	138	3	0.55	0.00	2	795KCM SSAC
85	0135 AXTON, VA	DANVILLE #2, VA	138	138	2	0.32	0.00	1	795KCM SSAC
86	0138 COLLINSVILLE	TAP LINE	138	138		0.00	0.00	0	
87	0141 DANVILLE B CIR, VA	EAST DANVILLE, VA	138	138	3	0.00	3.00	1	336KCM ACSR
88	0145 ALTAVISTA, VA	REUSENS, VA	138	138	1	5.00	0.00	2	795KCM ACSR
89	0145 ALTAVISTA, VA	REUSENS, VA	138	138	2	14.00	0.00	1	397KCM ACSR
90	0145 ALTAVISTA, VA	REUSENS, VA	138	138	1	6.00	0.00	1	795KCM ACSR

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
91	0145A BOONSBORO LOOP, VA		138	138	3	0.00	0.00	1	397KCM ACSR
92	0146 FIELDDALE, VA	RIDGEWAY, VA	138	138	1	10.00	0.00	1	397KCM ACSR
93	0148 CLINCH RIVER, VA	SALTVILLE #1A, VA	138	138	3	0.00	25.00	1	636KCM ACSR
94	0148 CLINCH RIVER, VA	SALTVILLE #1B, VA	138	138	3	26.00	0.00	1	1033KCM ACSR
95	0153 NORTH BRISTOL, VA	WEST KINGSPORT, VA	138	138	3	0.00	4.00	1	397KCM ACSR
96	0154 CLINCH RIVER, VA	SALTVILLE #2, VA	138	138	3	3.00	40.00	1	397KCM ACSR
97	0156 CLIFFORD, VA	SCOTTSVILLE, VA	138	138	3	29.00	0.00	1	397KCM ACSR
98	0156A CLIFFORD, VA	REUSENS, VA	138	138	3	23.00	4.00	1	795KCM ACSR
99	0156B BREMO, VA	SCOTTSVILLE, VA	138	138	3	7.00	0.00	1	397KCM ACSR
100	0160 CLOVERDALE, VA	REUSENS, VA	138	138	3	36.00	8.00	1	397KCM ACSR
101	0160 CLOVERDALE, VA	REUSENS, VA	138	138	1	1.00	0.00	0	636 KCM ACSR
102	0161 CLOVERDALE, VA	ROANOKE, VA	138	138	3	16.00	0.00	1	556KCM ACSR
103	0161 CLOVERDALE, VA	ROANOKE, VA	0	0	3	1.00	0.00	0	795KCM ACSR
104	0163 MOSELEY, VA	ROANOKE, VA	138	138	3	1.00	20.00	1	795KCM ACSR
105	0167 CLINCH RIVER, VA	GARDEN CREEK, VA	138	138	3	2.00	0.00	1	636KCM ACSR
106	0167 CLINCH RIVER, VA	GARDEN CREEK, VA	0	0	1	22.00	0.00	0	
107	0167A CLINCHFIELD LOOP SITE		138	138	1	0.00	0.00	1	636KCM ACSR
108	0168 EAST DANVILLE, VA	SMITH MOUNTAIN, VA	138	138	3	32.00	0.00	1	556KCM ACSR
109	0168A BEARSKIN TAP, VA		138	138	3	0.00	0.00	1	556KCM ACSR
110	0170 LEESVILLE, VA	SMITH MOUNTAIN, VA	138	138	3	0.00	8.00	1	556KCM ACSR
111	0170 OPOSSUM CREEK, VA	SMITH MOUNTAIN, VA	138	138	3	15.00	0.00	1	556KCM ACSR
112	0170 OPOSSUM CREEK, VA	SMITH MOUNTAIN, VA	0	0	1	19.00	0.00	0	
113	0173 ALTAVISTA, VA	LEESVILLE, VA	138	138	3	0.00	5.00	1	556KCM ACSR
114	0173 ALTAVISTA, VA	LEESVILLE, VA	0	0	1	3.00	0.00	0	
115	0191 BROADFORD, VA	NAGEL, TN	138	138	3	45.00	0.00	1	397KCM ACSR
116	0192 NORTH BRISTOL, VA	SPRING CREEK, VA	138	138	3	0.00	9.00	1	795 KCM ACSR
117	0193 BROADFORD, VA	SALTVILLE NO.2, VA	138	138	3	5.00	0.00	2	795KCM ACSR
118	0224 BRADLEY CIR-B, WV	GLEN LYN-HINTON	138	138	3	4.00	0.00	1	556KCM ACSR
119	0229 MERRIMAC TAP, VA		138	138	1	7.00	0.00	1	556KCM ACSR
120	0241 HUFFMAN, VA	WYTHE, VA	138	138	3	2.00	1.00	1	795KCM ACSR
121	0241 HUFFMAN, VA	WYTHE, VA	138	138	1	37.00	0.00	1	795KCM ACSR
122	0241A HUFFMAN, VA	JACKSONS FERRY, VA	138	138	3	0.00	2.00	1	1033KCM ACSR
123	0241A HUFFMAN, VA	JACKSONS FERRY, VA	0	0	1	8.00	0.00	0	
124	0248 CLAYTOR, VA	FIELDALE	138	138	3	0.00	0.00	1	556KCM ACSR
125	0248 CLAYTOR, VA	FIELDALE	0	0	1	38.00	0.00	0	
126	0249 FIELDALE, VA	WEST BASSETT, VA	138	138	3	0.00	0.00	1	556KCM ACSR
127	0249 FIELDALE, VA	WEST BASSETT, VA	0	0	1	6.00	0.00	0	
128	0256 LEBANON 138KV TAP VA		138	138	1	0.00	0.00	1	336KCM ACSR
129	0258 OPOSSUM CREEK, VA	PEAKSVIEW, VA	138	138	1	0.00	0.00	1	556KCM ACSR
130	0258 OPOSSUM CREEK, VA	PEAKSVIEW, VA	138	138	2	1.00	0.00	1	556KCM ACSR
131	0258 OPOSSUM CREEK, VA	PEAKSVIEW, VA	138	138	3	0.00	0.00	1	556KCM ACSR
132	0259 REGIS, VA	MONUMENT, VA	138	138	1	2.00	1.00	1	795KCM ACSR
133	0259A EAST DANVILLE, WV	EAST MONUMENT	138	138		4.00	0.00	0	

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134	0266 HANCOCK, VA	ROANOKE ELECTRIC STEEL, VA	138	138	3	1.00	0.00	1	795KCM ACSR
135	0266 HANCOCK, VA	ROANOKE ELECTRIC STEEL, VA	0	0	1	0.00	0.00	0	
136	0270 BLUEFIELD, WV	TAZEWELL, VA	138	138	1	20.00	0.00	1	795KCM ACSR
137	0270 BLUEFIELD, WV	TAZEWELL, VA	138	138	2	0.00	0.00	1	1033KCM ACSR
138	0289 COOPER RIDGE LOOP, VA		138	138	1	0.00	0.00	1	636KCM ACSR
139	0292 VINTON LOOP, VA		138	138	3	0.00	0.00	1	795KCM ACSR
140	0298 FLETCHERS RIDGE TAP,VA		138	138	1	0.00	0.00	1	300KCM CU
141	0300 DAN RIVER, NC	RIDGEWAY, VA	138	138	2	4.00	0.00	1	397KCM ACSR
142	0300 DAN RIVER, NC	RIDGEWAY, VA	138	138	1	0.00	0.00	1	397KCM ACSR
143	0300 DAN RIVER, NC	RIDGEWAY, VA	138	138	1	0.00	0.00	1	1033KCM ACSR
144	0309 EAST LYNCHBURG, VA	OPOSSUM CREEK, VA	138	138	3	3.00	0.00	1	1590KCM ACSR
145	0311 OPOSSUM CREEK, VA	REUSENS, VA	138	138	3	9.00	5.00	1	397KCM ACSR
146	0311 OPOSSUM CREEK, VA	REUSENS, VA	138	138	1	0.00	0.00	2	1033KCM ACSR
147	0312 BRUSH TAVERN TAP, VA		138	138	1	3.00	0.00	1	556KCM ACSR
148	0313 SKEGGS BRANCH, VA		138	138	1	0.00	0.00	1	397KCM ACSR
149	0320 EAST LYNCHBURG, VA	JOSHUA FALLS, VA	138	138	3	3.00	0.00	2	1590KCM ACSR
150	0320 EAST LYNCHBURG, VA	JOSHUA FALLS, VA	138	138	1	1.00	0.00	1	1590KCM ACSR
151	0321 JOSHUA FALLS, VA	OPOSSUM CREEK, VA	138	138	3	0.00	7.00	1	1590KCM ACSR
152	0322 JOSHUA FALLS, VA	REUSENS A&B, VA	138	138	3	7.00	0.00	2	556KCM ACSR
153	0322 JOSHUA FALLS, VA	REUSENS A&B, VA	138	138	3	0.00	0.00	2	1590KCM ACSR
154	0322 JOSHUA FALLS, VA	REUSENS A&B, VA	138	138	3	3.00	0.00	1	1590KCM ACSR
155	0322 JOSHUA FALLS, VA	REUSENS A&B, VA	138	138	1	0.00	0.00	1	1590KCM ACSR
156	0322 JOSHUA FALLS, VA	REUSENS A&B, VA	138	138	1	0.00	0.00	2	1590KCM ACSR
157	0333 BROADFORD, VA	RICHLANDS, VA	138	138	2	14.00	0.00	1	1033KCM ACSR
158	0338 BLUEFIELD, VA	SOUTH PRINCETON, VA	138	138	1	6.00	0.00	1	556KCM ACSR
159	0350 CLINCH RIVER, VA	NAGEL, TN	138	138	3	5.00	37.00	1	636KCM ACSR
160	0352 NAGEL, TN	REEDY CREEK, TN	138	138	3	0.00	5.00	1	556KCM ACSR
161	0354 NAGEL, TN	WEST KINGSPORT, TN	138	138	3	0.00	5.00	1	1590KCM ACSR
162	0358 AXTON, VA	DANVILLE #1-A, VA	138	138	3	0.00	16.00	1	336 KCM ACSR
163	0358 AXTON, VA	DANVILLE #1-A, VA	138	138	2	0.00	0.00	1	1033.5 ACSR
164	0359 AXTON, VA	MARTINSVILLE, VA	138	138	3	11.00	0.00	1	966KCM ACSR
165	0361 CLINCH RIVER, VA	SPRING CREEK, VA	138	138	3	18.00	4.00	1	636KCM ACSR
166	0365 DICKENS TAP		138	138	1	3.00	0.00	1	795KCM ACSR
167	0366 RUSTBURG TAP, VA		138	138	1	4.00	0.00	1	795KCM ACSR
168	0367 BURLINGTON HEIGHTS LOO		138	138	3	0.00	0.00	1	795KCM ACSR
169	0368 CLAY POOL HILL LOOP,VA		138	138	1	0.00	0.00	1	1033KCM ACSR
170	0369 BLAINE, VA	WESTLAKE	138	138	3	11.00	0.00	1	1033.5 KCM ACSR
171	0371 PENHOOK, VA	WESTLAKE	138	138	1	15.00	0.00	1	1033KCM ACSR
172	0371 PENHOOK, VA	WESTLAKE	138	138	1	0.00	0.00	2	1033KCM ACSR
173	0374 PATRIOT CENTRE EXT		138	138	3	3.00	0.00	1	795KCM ACSR

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
174	0375 PROGRESS PARK EXT		138	138	3	3.00	0.00	1	1590KCM ACSR
175	0380 FALLING BRANCH	MERRIMAC	138	138	1	6.00	0.00	1	1033 KCM ACSR
176	0380 FALLING BRANCH	MERRIMAC	138	138	1	1.00	0.00	1	1033 KCM ACSR
177	0380 FALLING BRANCH	MERRIMAC	69	138	1	1.00	0.00	1	1033 KCM ACSR
178	0381 LAKE FOREST, VA		138	138	3	3.00	0.00	2	1590KCM ACSR
179	0383 WEST SALEM LOOP, VA		138	138	3	0.00	0.00	1	795KCM ACSR
180	0385 CAPITALIZED SPARE PART	MAX MEADOW	138	138		0.00	0.00	1	
181	0388 TECH DRIVE	138KV EXTENSION	138	138	3	0.00	0.00	1	1590 KCM ACSR
182	0391 SHEFFIELD LOOP		138	138	3	0.00	0.00	1	795KCM ACSR
183	0394 GRAVES MILLS LOOP, VA		138	138	3	0.00	0.00	1	795KCM ACSR
184	0395 MONEL LOOP, VA		138	138	3	0.00	0.00	1	1590KCM ACSR
185	0396 BONSACK LOOP, VA		138	138	3	0.00	0.00	1	795KCM ACSR
186	0399 TANK HILL TAP, VA		138	138	1	1.00	0.00	1	795KCM ACSR
187	0409 LOONEY CREEK TAP, VA		138	138	3	10.00	0.00	1	795KCM ACSR
188	0414 RIVERVILLE TAP, VA		138	138	3	0.00	0.00	1	795KCM ACSR
189	0416 CLOVERDALE, VA	HUNTINGTON COURT, VA	138	138	3	6.00	0.00	1	795KCM ACSR
190	0417 BAILEYSVILLE, WV	HALES BRANCH, VA	138	138	3	0.00	0.00	1	636KCM ACSR
191	0417 BAILEYSVILLE, WV	HALES BRANCH, VA	0	0	1	6.00	0.00	0	
192	0419 PENHOOK, VA	SMITH MOUNTAIN, VA	138	138	3	7.00	0.00	1	1033KCM ACSR
193	0421 MOUNT UNION	CLOVERDALE	138	138	2	7.00	0.00	1	795KCM ACSR
194	0422 JACKSONS FERRY, VA	PEAK CREEK, VA	138	138	1	13.00	0.00	1	795KCM ACSR
195	0422 JACKSONS FERRY, VA	PEAK CREEK, VA	138	138	3	1.00	0.00	0	954KCM ACSR
196	0423 STONEWALL TAP		69	138	1	8.00	0.00	1	
197	0423 STONEWALL TAP		0	0	3	1.00	0.00	0	795 KCM ACSR
198	0427 EVINGTON 138KV TAP VA		138	138	2	0.00	0.00	0	397KCM ACSR
199	0433 HUFFMAN, VA	WILLIS GAP, VA	138	138	1	14.00	0.00	1	1033KCM ACSR
200	0434 GRASSY CREEK, VA	HALES BRANCH, VA	138	138	3	0.00	0.00	2	1033.5KCM ACSR
201	0434 GRASSY CREEK, VA	HALES BRANCH, VA	138	138	3	6.00	0.00	1	795KCM ACSR
202	0434 GRASSY CREEK, VA	HALES BRANCH, VA	0	0	1	2.00	0.00	0	
203	0435 DUTY, VA	138KV EXTENSION	138	138		0.00	0.00	1	
204	0459 GEORGE STREET	LYNBROOK	138	138	1	1.00	0.00	1	1233.6KCM ACSR/TW
205	0459 GEORGE STREET	LYNBROOK	138	138	2	2.00	0.00	1	1233.6KCM ACSR/TW
206	0460 BRUSH TAVERN	LYNBROOK	138	138	1	4.00	0.00	1	1233.6KCM ACSR/TW
207	0461 George Street	South Lynchburg	138	138	1	3.00	0.00	1	1233.6KCM ACSR/TW
208	0461 George Street	South Lynchburg	138	138	2	0.00	0.00	1	1233.6KCM ACSR/TW
209	0462 MATT FUNK EXT		138	138	3	5.00	0.00	0	1590 KCM ACSR
210	0464 HUNTINGTON COURT	ROANOKE	138	138	1	6.00	0.00	1	795 ACSR
211	0464 HUNTINGTON COURT	ROANOKE	138	138	1	0.00	0.00	1	1590KCM ACSR
212	0465 SUNSCAPE		138	138	1	1.00	0.00	2	1590KCM ACSR
213	0467 CLEARBROOK, VA	MATT FUNK, VA	138	138	1	0.00	0.00	1	1590KCM ACSR
214	0470 LOCKHART, VA		138	138	3	0.00	0.00	1	795KCM ACSR
215	0484 HORSEPEN	138KV EXTENSION	138	138		0.00	0.00	0	

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
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
216	0485 JACKSONS FERRY	WYTHE	138	138	2	5.00	0.00	1	1590KCM ACSR/MA2
217	0485 JACKSONS FERRY	WYTHE	138	138	3	13.00	0.00	2	1590KCM ACSR/MA2
218	0501 JACKSONS FERRY	BUS TIE #3	138	138	1	0.00	0.00	1	1590 KCM ACSR
219	0502 PROGRESS PARK TAP		138	138	2	1.00	0.00	1	1590KCM ACSR/MA2
220	0502 PROGRESS PARK TAP		138	138	1	0.00	0.00	1	1590KCM ACSR/MA2
221	0507 Cloverdale East	Cloverdale Tie Line No. 1	345	345	1	0.00	0.00	1	2 - 1926.9 KCM AC
222	0508 CLOVERDALE EAST	CLOVERDALE TIE LINE NO 2	345	345	1	0.00	0.00	1	2-1926.9KCM ACSR/
223	0509 CLOVERDALE 765	CLOVERDALE EAST	500	500	2	0.00	0.00	1	4-954KCM ACSR
224	0512 CLOVERDALE 765	CLOVERDALE 138	345	345	3	0.00	0.00	1	1590KCM ACSS
225	0513 WHITEWOOD EXT		138	138	1	1.00	0.00	2	1033.5KCM ACSR
226	0513 WHITEWOOD EXT		138	138	3	0.00	0.00	2	1033.5KCM ACSR
227	0514 BEARWALLOW	FARADAY	138	138	2	2.00	0.00	1	1033.5KCM ACSR
228	0515 FARADAY	TAZEWELL	138	138	2	7.00	0.00	1	1033.5KCM ACSR
229	0516 RICHLANDS	WHITEWOOD	138	138	2	8.00	0.00	1	1033.5KCM ACSR
230	0517 Town Creek	Progress Park	138	138	1	3.00	0.00	1	1033.5KCM ACSR
231	0517 Town Creek	Progress Park	138	138	2	7.00	0.00	1	1033.5KCM ACSR
232	0517 Town Creek	Progress Park	138	138	3	3.00	0.00	1	1033.5KCM ACSR
233	0518 TOWN CREEK	SOUTH BLUEFIELD	138	138	1	1.00	0.00	1	1033.5KCM ACSR
234	0518 TOWN CREEK	SOUTH BLUEFIELD	138	138	2	1.00	0.00	1	1033.5KCM ACSR
235	0518 TOWN CREEK	SOUTH BLUEFIELD	138	138	3	10.00	0.00	1	1033.5KCM ACSR
236	0519 OWENS DRIVE EXT		69	138	1	2.00	0.00	1	795KCM ACSR
237	0522 SOUTH ABINGDON EXT		138	138	1	4.00	0.00	2	1033.5KCM ACSR
238	0524 Joshua Falls 765/138kV Bus Tie No. 1		138	138	1	0.00	0.00	1	1590KCM ACSR
239	0537 WOLF GLADE EXTENSION		138	138	1	2.00	0.00	2	795KCM ACSR
240	0538 Elk Garden Tap		138	138	1	0.00	0.00	1	1590KCM ACSR
241	0538 Elk Garden Tap		138	138	2	0.00	0.00	1	336KCM ACSR
242	0541 IRONTO EXTENSION		138	138	1	0.00	0.00	2	1033.5KCM ACSR
243	0545 Tazewell Bus Tie No 1		138	138	1	0.00	0.00	1	1033.5KCM ACSR
244	0566 Berry Hill Extension		138	138	1	5.00	0.00	2	1033 KCM ACSR
245	0567 Glenmary Extension		138	138	3	0.00	0.00	2	795KCM ACSR
246	0569 HINTON	WEST VACO (VA)	138	138	3	0.00	0.00	1	336KCM ACSR
247	0571 Garden Creek	Baileysville (VA)	138	138	2	13.00	0.00	1	636KCM ACSR
248	0578 Redeye Extension		138	138	1	0.00	0.00	2	795KCM ACSR
249	0581 Museville Extension		138	138	1	0.00	0.00	2	1272 ACSS
250	0584 Wythe County Solar Farm Extension		138	138	1	0.08	0.00	1	556KCM ACSR
251	1004 KEYWOOD TAP		138	138	1	0.00	0.00	0	
252	1020 CLINCH RIVER	VIRGINA CITY	138	138		0.00	0.00	0	
253	7119 HANCOCK, VA	ROANOKE, VA TOWER 198	138	138		0.00	0.00	0	
254	7539 DAN, VA	CAROLINA	138	138		0.00	0.00	0	
255	8161 CVEC	SCOTTSVILLE	46	138	3	1.00	0.00	1	
256	BAILEYSVILLE, WV	TAZEWELL, VA	138	138	3	9.00	0.00	1	397KCM ACSR
257	BAILEYSVILLE, WV	TAZEWELL, VA	138	138	3	0.00	9.00	1	397KCM ACSR
258	MOSELEY, VA	REUSENS, VA	138	138	3	0.00	22.00	1	397KCM ACSR
259	STATE OF WEST VIRGINIA	STATE OF WEST VIRGINIA				0.00	0.00		

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
260	0276 AMOS, WV	HANGING ROCK, H	765	765	3	25.00	0.00	1	954KCM ACSR
261	0297 GAVIN, OH	MOUNTAINEER, WV	765	765	3	8.00	0.00	1	1351KCM ACSR
262	0296 KAMMER, WV	MOUNTAINEER, WV	765	765	3	19.00	0.00	1	1351KCM ACSR
263	0296 KAMMER, WV	MOUNTAINEER, WV	0	0	3	95.00	0.00	0	
264	0183 AMOS, WV	CULLODEN, WV	765	765	3	15.00	0.00	1	954KCM ACSR
265	0183A BAKER, KY	CULLODEN, WV	765	765	3	34.00	0.00	1	954KCM ACSR
266	0324 CULLODEN, WV	WYOMING, WV	765	765	3	58.00	0.00	1	1351KCM ACSR
267	0344 CULLODEN, WV	GAVIN, OH	765	765	3	42.00	0.00	1	1351KCM ACSR
268	0405 JACKSONS FERRY	WYOMING	765	765	3	32.00	0.00	1	795KCM ACSR
269	0295 AMOS, WV	MOUNTAINEER, WV	765	765	3	47.00	0.00	1	1351KCM ACSR
270	0185 BAKER, KY	BROADFORD, VA	765	765	3	4.00	0.00	1	954KCM ACSR
271	0263 AMOS, WV	GAVIN	765	765		0.00	0.00	1	
272	0012 BAKER, KY	TRI STATE, WV	345	345	3	6.00	0.00	1	954KCM ACSR
273	0003 KYGER CREEK, OH	SPORN, WV	345	345	3	12.00	0.00	1	1414KCM ACSR
274	0003 KYGER CREEK, OH	SPORN, WV	345	345	1	0.00	0.00	1	1272 ACSS
275	0004 MUSKINGUM, WV	SPORN, WV	345	345	3	0.00	2.00	1	1275KCM ACSR
276	0004 MUSKINGUM, WV	SPORN, WV	345	345	1	2.00	0.00	2	959.6 KCM ACSS
277	0005 KANAWHA, WV	MATT FUNK, VA	345	345	3	1.00	0.00	1	2156KCM ACSR
278	0005 KANAWHA, WV	MATT FUNK, VA	345	345	3	64.00	0.00	1	2-954KCM ACSR
279	0218 AMOS, WV	SPORN, WV	345	345	3	46.00	0.00	1	1563KCM ACSR
280	0006 KANAWHA, WV	SPORN, WV	345	345	3	0.00	62.00	1	1414KCM ACSR
281	0006A AMOS, WV	KANAWHA, WV	345	345	3	28.00	12.00	1	1563KCM ACSR
282	0011 KYGER CREEK, WV	TRI-STATE, WV	345	345	3	63.00	0.00	0	2303KCM ACSR
283	0011 KYGER CREEK, WV	TRI-STATE, WV	345	345	2	0.00	0.00	0	2303KCM ACSR
284	0013 LOGAN, WV	WYOMING #1-A, WV	138	138	3	12.00	14.00	1	1590KCM ACSR
285	0013 LOGAN, WV	WYOMING #1-B, WV	138	138	3	22.00	0.00	1	1590KCM ACSR
286	0015 BERWIND	FARADAY	138	138		0.00	0.00	0	
287	0016 BAILEYSVILLE, WV	TAZEWELL, VA	138	138	3	3.00	28.00	1	397KCM ACSR
288	0016 JIM BRANCH	YUKON	138	138		0.00	0.00	0	
289	0016A CARSWELL TAP, WV		138	138	3	1.00	1.00	1	397KCM ACSR
290	0017 BAILEYSVILLE, WV	TAZEWELL, VA	138	138	3	31.00	0.00	1	1590KCM ACSR
291	0018 BERWIND	YUKON	138	138		0.00	0.00	0	
292	0020 GLEN LYN, VA	SOUTH PRINCETON, WV	138	138	3	13.00	0.00	1	397KCM ACSR
293	0020A SOUTH PRINCETON, WV	SWITCHBACK A, WV	138	138	3	15.00	0.00	1	397KCM ACSR
294	0020B SOUTH PRINCETON, WV	SWITCHBACK B, WV	138	138	3	0.00	15.00	1	397KCM ACSR
295	0023 MINNIX MOUNTAIN LOOP		138	138	3	0.00	0.00	1	1033KCM ACSR
296	0024 SPEEDWAY TAP, WV		138	138	3	0.00	0.00	1	556KCM ACSR
297	0024 SPEEDWAY TAP, WV		0	0	1	7.00	0.00	0	
298	0028 CABIN CREEK, WV	KANAWHA #1, WV	138	138	3	0.00	3.00	1	556KICM ACSR
299	0029 CABIN CREEK, WV	KANAWHA #2, WV	138	138	3	3.00	0.00	1	556KCM ACSR
300	0031 BRADLEY, WV	KANAWHA #1, WV	138	138	3	0.00	27.00	1	556KCM ACSR
301	0032 BRADLEY CIR A, WV	GLEN LYN-HINTON, VA	138	138	3	0.00	41.00	1	556KCM ACSR
302	0035 STOTESBURY TAP, WV		138	138	1	0.00	0.00	1	795KCM ACSR
303	0035 STOTESBURY TAP, WV		138	138	2	6.00	0.00	1	795KCM ACSR
304	0045 LOGAN, WV	SPRIGG #1 & #2, WV	138	138	3	18.00	0.00	2	397KCM ACSR
305	0048 CHAUNCEY TAP, WV		138	138	3	4.00	0.00	1	397KCM ACSR
306	0049 BAILEYSVILLE, WV	KANAWHA #1, WV	138	138	3	46.00	0.00	1	636KCM ACSR

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
307	0049 BAILEYSVILLE, WV	KANAWHA #2, WV	138	138	3	0.00	46.00	1	636KCM ACSR
308	0049 BAILEYSVILLE, WV	KANAWHA #2, WV	0	0	1	0.00	0.00	0	
309	0052 BIM TAP, WV		138	138	1,3	12.00	0.00	1	556KCM ACSR
310	0053 BAILEYSVILLE, WV	HALES BRANCH, VA	138	138	3	0.00	0.00	2	636KCM ACSR
311	0053 BAILEYSVILLE, WV	HALES BRANCH, VA	138	138	1	21.00	0.00	1	636KCM ACSR
312	0055 GLEN LYN, VA	WYTHE, VA	138	138	3	1.00	0.00	1	556KCM ACSR
313	0055 GLEN LYN, VA	WYTHE, VA	138	138	3	0.00	1.00	1	556KCM ACSR
314	0067 JOHNS CREEK, KY	SPRIGG, WV	138	138	1	1.00	0.00	1	397KCM ACSR
315	0069 CABIN CREEK, WV	TURNER #1 CIR A, WV	138	138	3	23.00	0.00	1	336KCM ACSR
316	0070 CABIN CREEK, WV	TURNER #1 CIR B. WV	138	138	3	5.00	19.00	1	1590KCM ACSR/MA
317	0071 CABIN CREEK, WV	TURNER #2, WV	138	138	3	0.00	1.00	1	250KCM ACSR
318	0071 CABIN CREEK, WV	TURNER #2, WV	0	0	1	22.00	0.00	0	
319	0075 SOUTH POINT, OH	SPORN, WV	138	138	3	10.00	0.00	1	397KCM ACSR
320	0075 SOUTH POINT, OH	SPORN, WV	138	138	1	1.00	0.00	1	397KCM ACSR
321	0076 DARRAH, WV	NORTH PROCTORVILLE, OH	138	138	3	2.00	0.00	1	795KCM ACSR
322	0076 DARRAH, WV	NORTH PROCTORVILLE, OH	138	138	3	0.00	2.00	1	556KCM ACSR
323	0077 MILLBROOK, OH	SPORN, WV	138	138	3	9.00	0.00	1	477KCM ACSR
324	0077 MILLBROOK, OH	SPORN, WV	138	138	1	0.25	0.00	1	477KCM ACSR
325	0077A ADDISON LICK, WV	SPORN, WV	138	138	3	0.00	9.00	1	477KCM ACSR
326	0081 RAVENSWOOD, WV	SPORN #1, WV	138	138	3	1.00	0.00	1	795KCM ACSR
327	0081 RAVENSWOOD, WV	SPORN #2, WV	138	138	3	0.00	1.00	1	795KCM ACSR
328	0083 RAVENSWOOD, WV	SPORN #3, WV	138	138	3	1.00	0.00	1	795KCM ACSR
329	0083 RAVENSWOOD, WV	SPORN #4, WV	138	138	3	0.00	1.00	1	795KCM ACSR
330	0087 DARRAH, WV	TRI STATE, WV	138	138	3	10.00	4.00	1	397KCM
331	0088 TRI-STATE, WV	WEST HUNTINGTON, WV	138	138	3	0.00	6.00	1	397KCM ACSR
332	0090 SOUTH POINT, OH	TRI-STATE CIR A, WV	138	138	3	8.00	0.00	1	397KCM ACSR
333	0090 SOUTH POINT, OH	TRI-STATE CIR B, WV	138	138	3	0.00	7.00	1	1351KCM ACSR
334	0092 BELLEFONTE, KY	TRI STATE, WV	138	138	3	4.00	0.00	1	795KCM ACSR
335	0093 BIG SANDY	WEST HUNTINGTON, WV	138	138	2	0.00	0.00	2	1780KCM ACSR
336	0093 BIG SANDY	WEST HUNTINGTON, WV	138	138	3	3.00	0.00	1	1351KCM ACSR
337	0093 BIG SANDY	WEST HUNGINGTON, WV	0	0	3	16.00	0.00	0	
338	0094 BIG SANDY, KY	DEWEY, KY	138	138	3	0.00	0.00	1	636KCM ACSR
339	0095 CARBIDE MAIN, WV	TURNER, WV	138	138	3	0.00	0.00	1	1590 KCM ACSR
340	0096 CARBIDE #8, WV	CHEMICAL-TURNER A, WV	138	138	3	0.00	1.00	1	397KCM ACSR
341	0096 CARBIDE #8, WV	CHEMICAL-TURNER B, WV	138	138	3	7.00	0.00	1	1033KCM ACSR
342	0096 CARBIDE #8, WV	CHEMICAL-TURNER B, WV	138	138	3	1.00	0.00	2	1033KCM ACSR
343	0097 CAPITOL HILL, WV	CHEMICAL, WV	138	138	3	6.00	0.00	2	556KCM ACSR
344	0097 CAPITOL HILL, WV	CHEMICAL, WV	138	138	3	0.00	0.00	1	1272KCM ACSS
345	0098 CAPITOL HILL, WV	KANAWHA, WV	138	138	3	18.00	0.00	1	556KCM ACSR
346	0098 CAPITOL HILL, WV	KANAWHA, WV	138	138	3	3.00	0.00	1	556KCM ACSS
347	0098A FLATWOOD TAP 138KV		0	0		0.00	0.00	0	
348	0098A FLATWOOD TAP, WV		138	138	3	5.00	0.00	1	795KCM ACSR
349	0101 DEXTER, OH	SPORN CIR A, WV	138	138	3	0.00	9.00	1	397KCM ACSR

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designated (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) - (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)	Size of Conductor and Material (i)
350	0101 DEXTER, WV	SPORN CIR B, OH	138	138	3	9.00	0.00	1	397KCM ACSR
351	0101 DEXTER, WV	SPORN CIR B, OH	138	138	1	0.00	0.00	1	397KCM ACSR
352	0104 BANCROFT TAP, WV		138	138	3	1.00	0.00	1	556KCM ACSR
353	0194 CHESTERFIELD TAP, WV		138	138		0.00	0.00	0	
354	0210 BAILEYSVILLE, WV	WYOMING, WV	138	138	3	0.00	6.00	1	1590KCM ACSR
355	0210 BAILYESVILLE, WV	WYOMING, WV	138	138	3	0.00	5.00	1	1590KCM ACSR
356	0211 MULLENSVILLE LOOP, WV		138	138	3	1.00	1.00	1	556KCM ACSR
357	0212 PINNACLE CREEK LOOP, W		138	138	3	3.00	3.00	1	556KCM ACSR
358	0216 MULLENS, WV	TAMS MOUNTAIN, WV	138	138	2	9.00	0.00	1	556KCM ACSR
359	0216 MULLENS, WV	TAMS MOUNTAIN, WV	138	138	1	0.00	0.00	0	556KCM ACSR
360	0216B BRADLEY, WV	TAMS MOUNTAIN, WV	138	138	1	1.00	0.00	1	556KCM ACSR
361	0216B BRADLEY, WV	TAMS MOUNTAIN, WV	138	138	2	14.00	0.00	1	556KCM ACSR
362	0216B BRADLEY, WV	TAMS MOUNTAIN, WV	138	138	3	1.00	0.00	1	556KCM ACSR
363	0219 KINCAID LOOP, WV		138	138	3	0.00	0.00	1	556KCM ACSR
364	0220 KOPPERSTON LOOP, WV		138	138	3	0.00	0.00	1	1033KCM ACSR
365	0222 BRADLEY, WV	KANAWHA #2, WV	138	138	3	27.00	0.00	1	556KCM ACSR
366	0223 BRADLEY CIR B, WV	GLEN LYN-HINTON, VA	138	138	3	43.00	2.00	1	1590KCM ACSR
367	0225 AMOS	SPORN	138	138	3	0.00	11.00	0	397KCM ACSR
368	0225 AMOS, WV	SOUTH BUFFALO CIR B, WV	138	138	3	12.00	6.00	1	397KCM ACSR
369	0225 SOUTH BUFFALO, WV	SPORN CIR A, WV	138	138	3	0.00	31.00	1	397KCM ACSR
370	0225 SOUTH BUFFALO, WV	SPORN CIR B WV	138	138	3	36.00	0.00	1	1351KCM ACSR
371	0225A LEON LOOP, WV		138	138	3	0.00	0.00	1	1033KCM ACSR
372	0226 AMOS, WV	CHEMICAL #1 A, WV	138	138	3	1.00	8.00	1	397KCM ACSR
373	0226 AMOS, WV	CHEMICAL #1 B, WV	138	138	3	6.00	0.00	1	1033KCM ACSR
374	0226 AMOS, WV	CHEMICAL #2 A, WV	138	138	3	8.00	9.00	1	1033KCM ACSR
375	0226 AMOS, WV	CHEMICAL #2 B, WV	138	138	3	0.00	4.00	1	397KCM ACSR
376	0226 AMOS, WV	CHEMICAL 1A-2A AND 1B-2B	138	138	3	1.00	0.00	2	1033 KCM ACSR
377	0228 AMOS, WV	HOPKINS, WV	138	138	3	2.00	17.00	1	336KCM ACSR
378	0228 AMOS, WV	HOPKINS, WV	138	138	3	28.00	0.00	1	795KCM ACSR
379	0228 AMOS, WV	HOPKINS, WV	138	138	3	2.00	0.00	1	1590KCM ACSR/MA
380	0228A BETH TAP WV		138	138	1	1.00	0.00	1	336KCM ACSR
381	0230 AMOS, WV	TURNER #1, WV	138	138	3	12.00	0.00	1	1033KCM ACSR
382	0230 AMOS, WV	TURNER #2, WV	138	138	3	0.00	12.00	1	1033KCM ACSR
383	0237 AMOS, WV	DARRAH, WV	138	138	3	35.00	0.00	1	397KCM ACSR
384	0238 AMOS, WV	WEST HUNTINGTON, WV	138	138	3	5.00	41.00	1	1033KCM ACSR
385	0238 AMOS, WV	WEST HUNTINGTON, WV	0	0	1	0.00	0.00	0	
386	0238 PARK HILL TAP, WV		138	138	3	0.00	0.00	1	397KCM ACSR
387	0243 BOLT TAP, WV		138	138	1	6.00	0.00	1	795KCM ACSR
388	0245 GILBOA, WV	KANAWHA, WV	138	138	3	0.00	0.00	1	795KCM ACSR
389	0245 GILBOA, WV	KANAWHA, WV	0	0	1	15.00	0.00	0	
390	0246 BRADLEY, WV	DAMERON, WV	138	138	1	10.00	0.00	1	795KCM ACSR

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	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
391	0247 EAST HUNTINGTON, WV	NORTH PROCTORVILLE, OH	138	138	3	1.00	0.00	1	795KCMACSR
392	0268 ST ALBANS LOOP, WV		138	138	3	0.00	0.00	1	1033KCM ACSR
393	0271 BLUEFIELD, WV	TAZEWELL, VA	138	138	1	1.00	0.00	1	795KCM ACSR
394	0277 CABELL LOOP, WV		138	138	3	1.00	1.00	1	954KCM ACSR
395	0294 NORTH BECKLEY LOOP, WV		138	138	3	1.00	1.00	1	556KCM ACSR
396	0301 WHARTON TAP, WV		138	138	1	0.00	0.00	1	556KCM ACSR
397	0302 MILTON LOOP, WV		138	138	3	2.00	2.00	1	795KCM ACSR
398	0304 RUM CREEK TAP, WV		138	138	1	2.00	0.00	1	556KCM ACSR
399	0306 INEZ, KY	LOGAN, WV	138	138	3	0.00	1.00	1	795KCM ACSR
400	0306 INEZ, KY	LOGAN, WV	0	0	1	23.00	0.00	0	
401	0308 PAD FORK LOOP, WV		138	138	1	0.00	0.00	1	397KCM ACSR
402	0317 GRANT BRANCH TAP, WV		138	138	1	7.00	0.00	1	556KCM ACSR
403	0318 M&B TAP, WV		138	138	1	0.00	0.00	1	556KCM ACSR
404	0325 JIM BRANCH, WV	SWITCHBACK, WV	138	138	2	18.00	1.00	1	1033KCM ACSR
405	0326 RENSFORD LOOP, WV	KANAWHA, WV	138	138	3	1.00	0.00	1	556KCM ACSR
406	0328 RAGLAND LOOP, WV		138	138	1	1.00	0.00	1	556KCM ACSR
407	0330 JIM BRANCH, WV	WYOMING, WV	138	138	3	7.00	0.00	1	1590KCM ACSR
408	0330 JIM BRANCH, WV	WYOMING, WV	0	0	1	16.00	0.00	0	
409	0332 WELCH TAP, WV		138	138	1	0.00	0.00	1	795KCM ACSR
410	0336 CLENDENIN TAP		138	138	1	8.00	0.00	1	795KCM ACSR
411	0337 BLUEFIELD, WV	SOUTH PRINCETON, WV	138	138	2	8.00	0.00	1	556KCM ACSR
412	0337 BLUEFIELD, WV	SOUTH PRINCETON, WV	138	138	1	0.00	0.00	2	556KCM ACSR
413	0343 STONE BRANCH TAP, WV		138	138	1	6.00	0.00	1	795KCM ACSR
414	0346 PINE CREEK TAP, WV		138	138	1	2.00	0.00	1	556KCM ACSR
415	0356 PEMBERTON TAP, WV		138	138	1	0.00	0.00	1	336KCM ACSR
416	0356 PEMBERTON TAP, WV		138	138	2	1.00	0.00	1	336KCM ACSR
417	0356 PEMBERTON TAP, WV		138	138	3	1.00	0.00	1	336KCM ACSR
418	0357 GRASSY FALLS, WV	MCCLUNG, WV	138	138	1	0.00	0.00	1	954KCM ACSR
419	0364 GRASSY FORK TAP, WV		138	138	1	2.00	0.00	1	795KCM ACSR
420	0370 SOUTHRIDGE EXTENSION		138	138	1	2.00	0.00	2	1590KCM ACSR/MA
421	0372 JEHU EXT WV		138	138	3	1.00	0.00	1	556KCM ACSR
422	0376 DINGESS LOOP, WV		138	138	3	0.00	0.00	1	1033KCM ACSR
423	0376 DINGESS LOOP, WV		0	0	1	0.00	0.00	0	
424	0377 SPORN	CLINE ENERGY EXTENSION	138	138	1	0.00	0.00	1	397KCM ACSR
425	0378 CURRY LOOP, WV		138	138	3	2.00	2.00	1	1033KCM ACSR
426	0382 LANHAM, WV		138	138	1	1.00	0.00	2	795 KCM ACSR
427	0384 HINTON	WESTVACO, WV	138	138	3	13.00	0.00	1	556KCM ACSR
428	0384 HINTON	WESTVACO, WV	138	138	3	23.00	0.00	1	336KCM ACSR
429	0386 GARRISON WV		138	138	1	0.00	0.00	2	795 KCM ACSR
430	0387 LOGAN, WV	WYOMING #2, WV	138	138	3	23.00	0.00	1	1033KCM ACSR
431	0387 LOGAN, WV	WYOMING #2, WV	138	138	2	0.00	0.00	1	1033KCM ACSR
432	0389 GREENBRIER LOOP, WV		138	138	3	0.00	0.00	1	246KCM ACAR
433	0390 BELVA TAP, WV		138	138	3	1.00	1.00	1	954KCM ACSR

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
434	0393 RONCEVERTE LOOP, WV		138	138	3	0.00	0.00	1	4/0 ACSR
435	0401 HATFIELD, WV	SPRIGG, WV	138	138	1	11.00	0.00	1	1033KCM ACSR
436	0401A CINDERELLA LOOP, WV		138	138	3	0.00	0.00	1	1035KCM ACSR
437	0402 SISSON TAP, WV		138	138	3	10.00	1.00	1	795KCM ACSR
438	0402 SISSON TAP, WV		0	0	1	0.00	0.00	0	
439	0415 CLIFFTOP TAP, WV		138	138	3	3.00	0.00	1	795KCM ACSR
440	0420 FRANKS BRANCH		46	138	1	5.00	0.00	1	
441	0424 GLEN LYN, VA	SOUTH PRINCETON, WV	138	138	3	0.00	13.00	1	1351KCM ACSR
442	0426 BIG SANDY, KY	INEZ A&B, KY	138	138	3	8.00	0.00	1	795KCM ACSR
443	0428 SHARPLES TAP 138KV		138	138	1	7.00	0.00	1	795KCM ACSR
444	0429 MIDKIFF, WV	TRI STATE, WV	138	138	2	25.84	0.00	1	795KCM ACSR
445	0432 MUD FORK LOOP, WV		138	138	3	1.00	1.00	1	795KCM ACSR
446	0436 DAWES LOOP, 138KV, WV		138	138		0.00	0.00	0	
447	0463 CROOKED CREEK, WV		138	138	3	1.00	0.00	1	1033KCM ACSR
448	0466 IAEGER	WHARNCLIFFE, WV	46	138	3	6.00	0.00	1	556.5KCM26/7 AC
449	0471 HALLS RIDGE	SOUTH PRINCETON, WV	138	138	3	0.00	0.00	1	1590KCM ACSR
450	0472 MERRITS CREEK, WV		138	138	3	4.00	0.00	1	1033KCM ACSR
451	0473 CARETTA	JIM BRANCH	138	138		0.00	0.00	0	
452	0474 COBB, WV	THOROFARE CREEK	138	138	3	0.00	0.00	1	795 KCM ACSR
453	0475 PATRIOT COAL, WV	POINT LICK	138	138	3	0.00	0.00	1	556.5 KCM 26/7 AC
454	0477 BROAD RUN, WV	THOROFARE CREEK	138	138		1.00	0.00	1	
455	0478 POLYMER LOOP, WV		138	138	3	3.00	0.00	1	795 KCM ACSR
456	0478 POLYMER LOOP, WV		138	138	1	0.00	0.00	1	795KCM ACSR
457	0479 HARMON BRANCH	138KV EXTENSION	138	138	3	1.00	0.00	2	1033.5 KCM ACSR
458	0481 LAKEVIEW	138KV EXTENSION	138	138		0.00	0.00	0	
459	0482 CLARK BRANCH, WV	138KV EXTENSION	138	138		0.00	0.00	1	
460	0483 HERNSHAW	138KV EXTENSION	138	138	3	2.00	0.00	2	1590 KCM ACSR
461	0486 PAX BRANCH	138KV EXTENSION	138	138	3	1.00	0.00	2	1033.5 KCM ACSR
462	0487 PIERPONT	138KV EXTENSION	138	138	3	1.00	0.00	1	1033.5 KCM
463	0492 TRI-STATE	TWELVEPOLE CREEK	138	138	3	1.00	0.00	2	795 KCM ACSR
464	0503 CLINTWOOD EXTENSION		69	138	1	0.00	0.00	2	1033.5 KCM ACSR
465	0526 COMMONWEALTH CROSSING	138KV EXTENSION	138	138	1	6.00	0.00	2	1033 KCM ACSR
466	0527 COCO Extension		138	138	1	0.00	0.00	2	1033.5 KCM ACSR
467	0528 CAPITOL HILL	CHESTERFIELD AVE	69	138	1	0.00	0.00	1	1033.5 KCM ACSR
468	0536 SOAPSTONE EXTENSION		138	138	1	0.11	0.00	2	795 ACSR
469	0539 TRI-STATE 345KV - 138KV BUS TIE NO. 1		138	138	3	0.00	0.00	1	2-1590KCM ACSR
470	0568 GRANGSTON LOOP		138	138	3	0.00	0.00	2	556.5KCM ACSR
471	1005 CHERRY CREEK	CLIFFTOP	138	138	1	7.00	0.00	1	795 ACSR
472	1050 ROCKHOUSE		138	138		0.00	0.00	0	
473	1072 CLENDENIN, WV	MORRIS BRANCH	138	138	3	2.00	0.00	1	795 KCM ACSR
474	2123 SOUTH NEAL	WEST HUNTINGTON	69	138	3	2.00	0.00	1	
475	3484 COBB TAP		46	138	1	0.00	0.00	1	
476	3791 BOLT, WV	TRAP HILL, WV	46	138	1	6.00	0.00	1	

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
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
477	3827 BRADLEY	LAYLAND	69	138	1	12.00	0.00	1	
478	3827 BRADLEY	LAYLAND NO.2B	69	138	1	1.00	0.00	1	1158.4KCM ACSR/TW
479	3843 BIM, WV		47	138	3	0.00	0.00	1	
480	3843 BIM, WV		0	0	1	11.00	0.00	0	
481	AMERICAN ALLOYS, WV	SPORN, WV	138	138	3	0.00	0.00	1	556KCM ACSR
482	CAPITALIZED SPARE PARTS	0373,0379	138	138		0.00	0.00	1	
483	HOPKINS, WV	LOGAN, WV	138	138	3	8.00	11.00	1	336KCM ACSR
484	HOPKINS, WV	LOGAN, WV	138	138	3	19.00	0.00	1	336KCM ACSR
485	MULLENS, WV	WYOMING, WV	138	138	3	6.00	0.00	1	556KCM ACSR
486	MULLENS, WV	WYOMING, WV	0	0	1	17.00	0.00	0	
487	NORTH PROCTORVILLE, OH	SPORN, WV	138	138	3	0.00	10.00	1	397KCM ACSR
488						0.00	0.00		
489	Lines Under 138KV					1,478.46	181.00		
490	Line cost and expense are	not available by individual							
491	transmission line	Total shown in Column j - p							
36	TOTAL					4,995	1,330	475	

Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
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Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
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Line No.	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
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490	224,210,140	2,038,368,979	2,262,579,119	72,312	19,651,055		19,723,367
491							
36	224,210,140	2,038,368,979	2,262,579,119	72,312	19,651,055	0	19,723,367

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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 columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	0536 SOAPSTONE EXTENSION		0	1	1	2	2	795	ACSR		138
44	TOTAL		0		1	2	2				

Line No.	LINE COST					Construction
	Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(l)	(m)	(n)	(o)	(p)	(q)
1		782,614	311,957		1,094,571	
44		782,614	311,957		1,094,571	

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
1	NAGEL - TN	Transmission		500.00	138.00	13.80	750.00	3	0
2	NAGEL - TN	Transmission		500.00	230.00	13.80	750.00	3	0
3	NAGEL - TN	Transmission		138.00	34.50	0.00	30.00	1	0
4	ABERT - VA	Transmission		69.00	12.00	0.00	22.40	1	0
5	ABERT - VA	Transmission		69.00	0.00	0.00	0.00	0	0
6	ABINGDON - VA	Transmission		138.00	70.50	13.09	90.00	1	0
7	ABINGDON - VA	Transmission		138.00	34.50	0.00	50.00	2	0
8	ABINGDON - VA	Transmission		138.00	13.09	0.00	22.40	1	0
9	ALUM RIDGE - VA	Transmission		138.00	33.00	12.00	9.38	1	0
10	AMHERST - VA	Transmission		69.00	0.00	0.00	0.00	0	0
11	AMHERST - VA	Transmission		69.00	13.09	0.00	25.00	1	0
12	ARCHER CREEK - VA	Transmission		69.00	12.00	0.00	10.50	1	0
13	ARROWHEAD - VA	Transmission		69.00	13.09	0.00	12.00	1	0
14	ATKINS - VA	Transmission		138.00	36.20	0.00	18.00	1	0
15	AUSTINVILLE - VA	Transmission		138.00	34.50	0.00	30.00	1	0
16	AXTON - VA	Transmission		765.00	0.00	0.00	0.00	0	0
17	AXTON - VA	Transmission		765.00	138.00	13.80	750.00	3	0
18	AXTON - VA	Transmission		138.00	0.00	0.00	0.00	0	0
19	BASSETT - VA	Transmission		69.00	12.00	0.00	25.00	1	0
20	BASSETT WALKER - VA	Transmission		34.50	7.50	0.00	3.75	3	0
21	BASSETT WALKER - VA	Transmission		34.50	7.20	0.00	5.64	3	0
22	BEARWALLOW - VA	Transmission		138.00	70.50	13.09	54.00	1	0
23	BENT MOUNTAIN - VA	Transmission		138.00	34.00	0.00	10.50	1	0
24	BENT MOUNTAIN - VA	Transmission		138.00	13.09	0.00	8.40	1	0
25	BIG ROCK - VA	Transmission		34.50	13.65	0.00	5.00	1	0
26	BLACKWATER - VA	Transmission		34.50	0.00	0.00	0.00	0	0
27	BLACKWATER - VA	Transmission		34.50	12.00	0.00	20.00	1	0
28	BLAINE - VA	Transmission		138.00	34.50	0.00	30.00	1	0
29	BLAINE - VA	Transmission		138.00	13.09	0.00	8.40	1	0
30	BLAINE - VA	Transmission		138.00	0.00	0.00	0.00	0	0
31	BLUE RIDGE - VA	Transmission		34.50	13.09	0.00	5.00	1	0
32	BLUE RIDGE - VA	Transmission		12.00	4.00	0.00	0.10	1	0
33	BONSACK - VA	Transmission		138.00	34.50	0.00	30.00	1	0
34	BOONSBORO - VA	Transmission		138.00	13.09	0.00	20.00	1	0
35	BOTETOURT - VA	Transmission		69.00	12.00	0.00	25.00	1	0
36	BOXWOOD - VA	Transmission		138.00	13.09	0.00	12.00	1	0
37	BROADFORD 765KV - VA	Transmission		13.80	0.00	0.00	0.00	0	0
38	BROADFORD 765KV - VA	Transmission		765.00	0.00	0.00	0.00	0	0
39	BROADFORD 765KV - VA	Transmission		138.00	0.00	0.00	0.00	0	0
40	BROADFORD 765KV - VA	Transmission		765.00	138.00	13.80	750.00	3	0
41	BROADFORD 765KV - VA	Transmission		765.00	500.00	13.80	1500.00	3	0
42	BROCKWAY GLASS - VA	Transmission		69.00	4.00	0.00	9.38	1	0
43	BROOKVILLE - VA	Transmission		138.00	13.09	0.00	22.40	1	0
44	BRUSH TAVERN - VA	Transmission		138.00	34.50	0.00	60.00	2	0
45	CATAWBA - VA	Transmission		138.00	69.00	34.50	130.00	1	0
46	CLEARBROOK - VA	Transmission		138.00	13.09	0.00	42.40	2	0
47	CLIFFORD - VA	Transmission		138.00	46.00	0.00	20.00	1	0
48	CLIFFORD - VA	Transmission		46.00	0.00	0.00	0.00	0	0
49	CLIFFORD - VA	Transmission		138.00	69.00	46.00	50.00	1	0
50	CLINCHFIELD - VA	Transmission		69.00	0.00	0.00	0.00	0	0
51	CLINCHFIELD - VA	Transmission		138.00	70.50	36.20	90.00	1	0
52	CLINTWOOD - VA	Transmission		69.00	12.00	0.00	20.00	1	0

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53	CLINTWOOD - VA	Transmission		69.00	0.00	0.00	0.00	0	0
54	CLOVERDALE 765KV - VA	Transmission		765.00	528.00	13.80	1950.00	3	0
55	CLOVERDALE 765KV - VA	Transmission		138.00	70.50	13.09	130.00	0	1
56	CLOVERDALE 765KV - VA	Transmission		138.00	70.50	13.09	130.00	0	1
57	CLOVERDALE 765KV - VA	Transmission		138.00	70.50	13.09	78.00	0	1
58	CLOVERDALE 765KV - VA	Transmission		138.00	70.50	13.09	78.00	0	1
59	CLOVERDALE 765KV - VA	Transmission		138.00	70.50	36.20	78.00	0	1
60	CLOVERDALE 765KV - VA	Transmission		138.00	70.50	36.20	78.00	0	1
61	CLOVERDALE 765KV - VA	Transmission		138.00	70.50	46.00	90.00	0	1
62	CLOVERDALE EAST 500KV - VA	Transmission		500.00	345.00	13.80	4500.00	9	0
63	CORNING GLASS (AP) - VA	Transmission		69.00	0.00	0.00	0.00	0	0
64	CORNING GLASS (AP) - VA	Transmission		69.00	4.00	0.00	8.40	1	0
65	COVE ROAD - VA	Transmission		69.00	13.09	0.00	12.00	1	0
66	DAN RIVER RESEARCH - VA	Transmission		12.00	0.60	0.00	0.25	1	0
67	DANVILLE - VA	Transmission		138.00	0.00	0.00	0.00	0	0
68	DANVILLE - VA	Transmission		138.00	0.00	0.00	0.00	0	0
69	EAST DANVILLE - VA	Transmission		69.00	0.00	0.00	0.00	0	0
70	EAST DANVILLE - VA	Transmission		69.00	12.00	0.00	8.40	1	0
71	EAST DANVILLE - VA	Transmission		230.00	138.00	34.50	1500.00	2	0
72	EAST DANVILLE - VA	Transmission		138.00	0.00	0.00	0.00	0	0
73	EAST DANVILLE - VA	Transmission		138.00	69.50	13.09	60.00	1	0
74	EAST LYNCHBURG - VA	Transmission		138.00	69.00	34.50	196.00	1	0
75	EAST MONUMENT - VA	Transmission		138.00	0.00	0.00	0.00	0	0
76	EDGEMONT - VA	Transmission		138.00	13.09	0.00	22.40	1	0
77	ELK GARDEN - VA	Transmission		138.00	36.20	0.00	30.00	1	0
78	ELK GARDEN - VA	Transmission		138.00	13.09	0.00	7.50	1	0
79	ELK GARDEN - VA	Transmission		138.00	34.50	0.00	30.00	1	0
80	FIELDALE - VA	Transmission		69.00	0.00	0.00	0.00	0	0
81	FIELDALE - VA	Transmission		138.00	0.00	0.00	0.00	0	0
82	FIELDALE - VA	Transmission		138.00	70.50	36.20	78.00	1	0
83	GARDEN CREEK - VA	Transmission		138.00	69.50	13.09	84.00	1	0
84	GARDEN CREEK - VA	Transmission		138.00	0.00	0.00	0.00	0	0
85	GLADE - VA	Transmission		69.00	12.00	0.00	10.50	1	0
86	GLADE - VA	Transmission		69.00	0.00	0.00	0.00	0	0
87	GLADE - VA	Transmission		69.00	34.50	0.00	30.00	1	0
88	GLAMORGAN - VA	Transmission		34.50	4.00	0.00	9.38	1	0
89	GLEN LYN - VA	Transmission		138.00	0.00	0.00	0.00	0	0
90	GLEN LYN - VA	Transmission		138.00	0.00	0.00	0.00	0	0
91	GLEN LYN - VA	Transmission		138.00	0.00	0.00	0.00	0	0
92	GLENWOOD (AP) - VA	Transmission		12.00	0.24	0.00	0.33	2	0
93	GLENWOOD (AP) - VA	Transmission		13.20	0.24	0.00	0.17	1	0
94	GLENWOOD (AP) - VA	Transmission		12.00	0.24	0.00	0.17	0	1
95	HALES BRANCH - VA	Transmission		69.00	0.00	0.00	0.00	0	0
96	HALES BRANCH - VA	Transmission		138.00	69.00	12.00	84.00	1	0
97	HANCOCK - VA	Transmission		34.50	0.00	0.00	0.00	0	0
98	HANCOCK - VA	Transmission		138.00	0.00	0.00	0.00	0	0
99	HANCOCK - VA	Transmission		34.50	0.00	0.00	0.00	0	0
100	HANCOCK - VA	Transmission		138.00	0.00	0.00	0.00	0	0
101	HANCOCK - VA	Transmission		34.50	36.20	0.00	15.00	1	0
102	HANS MEADOW - VA	Transmission		69.00	13.09	0.00	25.00	1	0
103	HANSONVILLE - VA	Transmission		138.00	13.09	0.00	20.00	1	0
104	HAYSI - VA	Transmission		69.00	12.00	0.00	20.00	1	0

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105	HILLMAN HIGHWAY - VA	Transmission		69.00	12.00	0.00	22.40	1	0
106	HILLSVILLE - VA	Transmission		34.50	12.00	0.00	6.75	2	0
107	HUFFMAN - VA	Transmission		138.00	0.00	0.00	0.00	0	0
108	HUNTINGTON COURT - VA	Transmission		69.00	0.00	0.00	0.00	0	0
109	HURLEY - VA	Transmission		69.00	12.00	0.00	22.40	1	0
110	INDEPENDENCE - VA	Transmission		69.00	34.50	0.00	20.00	1	0
111	INDEPENDENCE - VA	Transmission		69.00	12.00	0.00	10.50	1	0
112	JACKSONS FERRY - VA	Transmission		765.00	500.00	13.80	1300.00	3	0
113	JACKSONS FERRY - VA	Transmission		20.78	0.00	0.00	0.00	0	0
114	JACKSONS FERRY - VA	Transmission		13.20	0.00	0.00	0.00	0	0
115	JACKSONS FERRY - VA	Transmission		765.00	0.00	13.80	250.00	2	0
116	JACKSONS FERRY - VA	Transmission		765.00	138.00	0.00	250.00	2	0
117	JACKSONS FERRY - VA	Transmission		765.00	138.00	13.80	1500.00	7	0
118	JOSHUA FALLS 138KV - VA	Transmission		138.00	0.00	0.00	0.00	0	0
119	MEADOWVIEW - VA	Transmission		138.00	69.00	34.50	56.00	1	0
120	MEADOWVIEW - VA	Transmission		138.00	13.09	0.00	20.00	1	0
121	MELROSE - VA	Transmission		69.00	12.00	0.00	22.40	1	0
122	MERRIMAC - VA	Transmission		138.00	69.00	13.09	78.00	1	0
123	MERRIMAC - VA	Transmission		138.00	69.00	12.00	128.00	1	0
124	MIDWAY (AP) - VA	Transmission		69.00	4.00	0.00	12.25	2	0
125	MOHAWK RUBBER - VA	Transmission		69.00	2.40	0.00	25.00	2	0
126	MONEL - VA	Transmission		138.00	13.09	0.00	20.00	1	0
127	MONETA - VA	Transmission		138.00	34.50	0.00	30.00	1	0
128	MONROE (AP) - VA	Transmission		69.00	13.09	0.00	20.00	1	0
129	MONTEREY - VA	Transmission		69.00	12.00	0.00	10.50	1	0
130	MORGANS CUT - VA	Transmission		138.00	70.50	36.20	120.00	1	0
131	MOUNT UNION - VA	Transmission		69.00	0.00	0.00	0.00	0	0
132	MOUNT UNION - VA	Transmission		69.00	34.50	0.00	30.00	1	0
133	MOUNT UNION - VA	Transmission		138.00	69.00	34.50	130.00	1	0
134	MOUNT UNION - VA	Transmission		69.00	12.00	0.00	20.00	1	0
135	MOUNT VIEW - VA	Transmission		69.00	12.00	0.00	22.40	1	0
136	NORTH BLACKSBURG - VA	Transmission		138.00	13.09	0.00	22.40	1	0
137	NORTH CLAYTOR - VA	Transmission		138.00	69.00	34.50	200.00	1	0
138	OAK LEVEL - VA	Transmission		138.00	13.09	0.00	20.00	1	0
139	PATRIOT CENTRE - VA	Transmission		138.00	34.50	0.00	30.00	1	0
140	PEAK CREEK - VA	Transmission		138.00	13.09	0.00	20.00	1	0
141	PEAK CREEK - VA	Transmission		138.00	34.50	0.00	30.00	1	0
142	PEAKLAND - VA	Transmission		69.00	12.00	0.00	20.00	1	0
143	PLANTATION PIPELINE - VA	Transmission		34.50	7.50	0.00	4.50	3	0
144	RADFORD - VA	Transmission		34.50	0.00	0.00	0.00	0	0
145	RED HILL - VA	Transmission		138.00	13.09	0.00	8.40	1	0
146	REUSENS - VA	Transmission		138.00	0.00	0.00	0.00	0	0
147	REUSENS - VA	Transmission		138.00	69.00	13.09	130.00	1	0
148	RIDGEWAY - VA	Transmission		138.00	0.00	0.00	0.00	0	0
149	RIDGEWAY - VA	Transmission		138.00	0.00	0.00	0.00	0	0
150	RIDGEWAY - VA	Transmission		138.00	0.00	0.00	0.00	0	0
151	RIGIS - VA	Transmission		138.00	69.00	12.00	115.00	1	0
152	RIVERVILLE - VA	Transmission		138.00	0.00	0.00	0.00	0	0
153	SALTVILLE - VA	Transmission		138.00	13.09	0.00	10.50	1	0
154	SCHUYLER - VA	Transmission		46.00	7.20	0.00	0.83	0	1
155	SCHUYLER - VA	Transmission		46.00	7.20	0.00	2010.00	3	0
156	SCOTTSVILLE (AP) - VA	Transmission		46.00	0.00	0.00	0.00	0	0

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157	SHIPMAN - VA	Transmission		46.00	12.00	0.00	4.70	1	0
158	SKEGGS BRANCH - VA	Transmission		138.00	69.00	4.00	30.00	1	0
159	SKIMMER - VA	Transmission		69.00	12.00	0.00	30.00	1	0
160	SKIMMER - VA	Transmission		115.00	69.00	12.00	112.00	2	0
161	SOUTH LYNCHBURG - VA	Transmission		138.00	13.09	0.00	40.00	2	0
162	SOUTH LYNCHBURG - VA	Transmission		138.00	70.50	36.20	78.00	1	0
163	SPRING CREEK - VA	Transmission		138.00	13.09	0.00	21.00	2	0
164	STANLEYTOWN - VA	Transmission		69.00	12.00	0.00	22.40	1	0
165	STARKEY - VA	Transmission		138.00	13.09	0.00	40.00	2	0
166	STOCKTON - VA	Transmission		138.00	36.20	0.00	18.00	1	0
167	STUART - VA	Transmission		69.00	12.00	0.00	10.50	1	0
168	STUART - VA	Transmission		69.00	0.00	0.00	0.00	0	0
169	STUART - VA	Transmission		69.00	34.50	0.00	30.00	1	0
170	SUNSCAPE - VA	Transmission		138.00	12.00	0.00	20.00	1	0
171	TANK HILL - VA	Transmission		138.00	13.09	0.00	12.00	1	0
172	TAZEWELL - VA	Transmission		138.00	0.00	0.00	0.00	0	0
173	TAZEWELL - VA	Transmission		138.00	34.50	0.00	30.00	1	0
174	TAZEWELL - VA	Transmission		34.50	13.00	0.00	6.25	1	0
175	TECH DRIVE - VA	Transmission		138.00	12.00	0.00	20.00	1	0
176	THOMAS (AP) - VA	Transmission		34.50	7.20	0.00	3.00	3	0
177	VINTON - VA	Transmission		138.00	36.20	0.00	36.00	2	0
178	WALNUT AVENUE - VA	Transmission		69.00	12.00	0.00	22.40	1	0
179	WALTON PARK - VA	Transmission		69.00	2.40	0.00	2.00	1	0
180	WASENA - VA	Transmission		69.00	13.09	0.00	20.00	1	0
181	WEST BASSETT - VA	Transmission		69.00	0.00	0.00	0.00	0	0
182	WEST BASSETT - VA	Transmission		138.00	69.00	34.50	128.00	1	0
183	WEST BASSETT - VA	Transmission		34.50	34.50	0.00	25.00	1	0
184	WESTLAKE - VA	Transmission		138.00	34.50	0.00	60.00	2	0
185	WHETSTONE BRANCH - VA	Transmission		69.00	0.00	0.00	0.00	0	0
186	WITT - VA	Transmission		69.00	4.36	0.00	12.50	1	0
187	WURNO - VA	Transmission		138.00	0.00	0.00	0.00	0	0
188	WYTHE - VA	Transmission		138.00	34.50	0.00	35.00	1	0
189	WYTHE - VA	Transmission		138.00	34.00	0.00	25.00	1	0
190	AMBLER RIDGE - WV	Transmission		138.00	36.20	34.50	72.00	6	0
191	AMEAGLE - WV	Transmission		46.00	7.20	0.00	2.49	3	0
192	AMONATE LIGHTS - WV	Transmission		34.50	7.20	0.00	0.75	3	0
193	AMOS 345KV - WV	Transmission		345.00	138.00	34.50	1350.00	2	0
194	AMOS 345KV - WV	Transmission		345.00	138.00	34.50	675.00	0	1
195	AMOS 765KV - WV	Transmission		765.00	138.00	13.80	750.00	3	0
196	AMOS 765KV - WV	Transmission		138.00	70.50	46.00	130.00	0	1
197	AMOS 765KV - WV	Transmission		765.00	345.00	34.50	1500.00	3	0
198	APPLE GROVE - WV	Transmission		69.00	12.00	0.00	10.50	1	0
199	APPLE GROVE - WV	Transmission		138.00	69.00	12.00	56.00	1	0
200	BAILEYSVILLE - WV	Transmission		46.00	0.00	0.00	0.00	0	0
201	BANCROFT - WV	Transmission		138.00	34.50	0.00	20.00	1	0
202	BANCROFT - WV	Transmission		0.00	0.00	0.00	0.00	0	0
203	BANCROFT - WV	Transmission		138.00	69.00	12.00	67.20	1	0
204	BANCROFT - WV	Transmission		138.00	13.09	0.00	25.00	1	0
205	BARNETT - WV	Transmission		69.00	12.00	0.00	20.00	1	0
206	BARNETT - WV	Transmission		69.00	13.09	0.00	12.00	1	0
207	BECCO - WV	Transmission		46.00	13.09	0.00	7.50	1	0
208	BECKLEY - WV	Transmission		46.00	0.00	0.00	0.00	0	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
209	BELCHER MOUNTAIN - WV	Transmission		88.00	14.00	0.00	4.50	3	0
210	BELLE - WV	Transmission		46.00	12.00	0.00	20.00	1	0
211	BLUE PENNANT - WV	Transmission		69.00	0.00	0.00	0.00	0	0
212	BLUEFIELD AVENUE - WV	Transmission		138.00	13.09	0.00	22.40	1	0
213	BLUEFIELD AVENUE - WV	Transmission		138.00	13.09	0.00	22.40	1	0
214	BOLT - WV	Transmission		46.00	0.00	0.00	0.00	0	0
215	BOONE - WV	Transmission		46.00	0.00	0.00	0.00	0	0
216	BOONE - WV	Transmission		46.00	12.00	0.00	4.69	1	0
217	BORDERLAND - WV	Transmission		138.00	13.09	0.00	20.00	1	0
218	BRIAR MOUNTAIN - WV	Transmission		46.00	7.20	0.00	3.00	3	0
219	BRIDGE - WV	Transmission		69.00	13.09	0.00	15.00	1	0
220	BROWNSVILLE (AP) - WV	Transmission		69.00	12.00	0.00	6.25	1	0
221	CHEMICAL - WV	Transmission		46.00	0.00	0.00	0.00	0	0
222	CRAB ORCHARD - WV	Transmission		46.00	12.00	0.00	3.75	1	0
223	CROOKED CREEK - WV	Transmission		138.00	13.09	0.00	20.00	1	0
224	CROSS LANES - WV	Transmission		69.00	13.09	0.00	12.00	1	0
225	CURRY - WV	Transmission		138.00	13.09	0.00	20.00	1	0
226	DALEWOOD - WV	Transmission		138.00	13.09	0.00	20.00	1	0
227	DARRAH - WV	Transmission		138.00	69.00	34.50	90.00	1	0
228	DARRAH - WV	Transmission		138.00	13.09	0.00	75.00	1	0
229	DARRAH - WV	Transmission		138.00	13.09	0.00	22.40	1	0
230	EAST HUNTINGTON - WV	Transmission		138.00	34.50	0.00	30.00	1	0
231	EAST HUNTINGTON - WV	Transmission		34.50	12.00	0.00	9.38	1	0
232	ELK CREEK - WV	Transmission		46.00	12.00	0.00	3.75	1	0
233	ELMO - WV	Transmission		69.00	12.00	0.00	5.00	1	0
234	FARADAY 138KV - WV	Transmission		34.50	0.00	0.00	0.00	0	0
235	FARADAY 138KV - WV	Transmission		34.50	0.00	0.00	0.00	0	0
236	FLATWOOD - WV	Transmission		138.00	34.50	0.00	30.00	1	0
237	FLATWOOD - WV	Transmission		138.00	12.47	0.00	22.40	1	0
238	FOUR POLE CREEK - WV	Transmission		34.50	4.16	0.00	4.50	3	0
239	FULKS - WV	Transmission		34.50	13.09	0.00	9.38	1	0
240	GALLAGHER - WV	Transmission		46.00	12.00	0.00	4.69	1	0
241	GILBERT - WV	Transmission		46.00	0.00	0.00	0.00	0	0
242	GLEN WHITE - WV	Transmission		46.00	12.00	0.00	6.25	1	0
243	HALLS RIDGE - WV	Transmission		138.00	34.50	0.00	30.00	1	0
244	HARDY - WV	Transmission		46.00	7.20	0.00	4.50	3	0
245	HINTON (AP) - WV	Transmission		138.00	0.00	0.00	0.00	0	0
246	HUGHESTON - WV	Transmission		46.00	2.40	0.00	2.50	3	0
247	HURRICANE - WV	Transmission		69.00	12.00	0.00	25.00	1	0
248	HURRICANE - WV	Transmission		69.00	0.00	0.00	0.00	0	0
249	ITMANN - WV	Transmission		138.00	13.09	0.00	22.40	1	0
250	KANAWHA RIVER - WV	Transmission		138.00	0.00	0.00	0.00	0	0
251	KANAWHA RIVER - WV	Transmission		345.00	138.00	13.80	450.00	1	0
252	KANAWHA RIVER - WV	Transmission		138.00	13.09	0.00	20.00	1	0
253	KENOVA - WV	Transmission		138.00	34.50	0.00	30.00	1	0
254	LAVALETTE - WV	Transmission		138.00	34.50	0.00	30.00	1	0
255	LOGAN - WV	Transmission		138.00	0.00	0.00	0.00	0	0
256	LOUP CREEK - WV	Transmission		46.00	12.00	0.00	3.00	1	0
257	MAMMOTH - WV	Transmission		46.00	12.00	0.00	3.75	1	0
258	MARMET - WV	Transmission		46.00	12.00	0.00	7.00	1	0
259	MARSH FORK - WV	Transmission		46.00	12.00	0.00	10.50	1	0
260	PAD FORK - WV	Transmission		138.00	34.50	0.00	20.00	1	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
261	PANTHER - WV	Transmission		46.00	7.20	0.00	4.50	3	0
262	PEYTONA - WV	Transmission		46.00	13.09	0.00	10.50	1	0
263	PINE CREEK - WV	Transmission		138.00	13.09	0.00	12.50	1	0
264	PRINCETON - WV	Transmission		34.50	12.00	0.00	20.00	2	0
265	PUTNAM VILLAGE - WV	Transmission		69.00	13.09	0.00	20.00	1	0
266	RAGLAND - WV	Transmission		138.00	34.50	0.00	25.00	1	0
267	RAVENSWOOD - WV	Transmission		69.00	0.00	0.00	0.00	0	0
268	RAVENSWOOD - WV	Transmission		69.00	13.09	0.00	25.00	1	0
269	RENSFORD - WV	Transmission		138.00	34.50	0.00	25.00	1	0
270	RICH CREEK - WV	Transmission		46.00	12.00	0.00	10.50	1	0
271	RONDA - WV	Transmission		46.00	0.00	0.00	0.00	0	0
272	RUTH - WV	Transmission		138.00	13.09	0.00	20.00	1	0
273	SCARBRO - WV	Transmission		46.00	0.00	0.00	0.00	0	0
274	SCARBRO - WV	Transmission		46.00	12.00	0.00	35.00	2	0
275	SKIN FORK - WV	Transmission		46.00	12.00	0.00	8.40	1	0
276	SOPHIA - WV	Transmission		46.00	0.00	0.00	0.00	0	0
277	SOURWOOD - WV	Transmission		138.00	13.09	0.00	8.40	1	0
278	SOUTH BLUEFIELD - WV	Transmission		138.00	13.09	0.00	30.00	1	0
279	SOUTH BUFFALO - WV	Transmission		138.00	13.09	0.00	60.00	3	0
280	SOUTH BUFFALO - WV	Transmission		138.00	36.20	0.00	30.00	1	0
281	SOUTH CHARLESTON - WV	Transmission		46.00	12.00	0.00	22.40	1	0
282	SOUTH HILLS - WV	Transmission		46.00	12.00	0.00	22.40	1	0
283	SOUTH HILLS - WV	Transmission		46.00	13.09	0.00	25.00	1	0
284	SOUTH NEAL - WV	Transmission		69.00	13.09	0.00	12.00	1	0
285	SOUTH NEAL - WV	Transmission		69.00	0.00	0.00	0.00	0	0
286	SPORN 345KV - WV	Transmission		345.00	137.50	13.80	1350.00	3	0
287	SPRIGG - WV	Transmission		138.00	69.00	46.00	84.00	1	0
288	SPRIGG - WV	Transmission		138.00	13.20	12.00	9.38	1	0
289	ST. ALBANS - WV	Transmission		138.00	13.09	0.00	50.00	2	0
290	STONE BRANCH - WV	Transmission		138.00	34.50	0.00	25.00	1	0
291	STOTESBURY - WV	Transmission		138.00	13.09	0.00	10.50	1	0
292	SUN MINE - WV	Transmission		46.00	12.00	0.00	20.00	1	0
293	SUNDIAL - WV	Transmission		46.00	0.00	0.00	0.00	0	0
294	SWITCHBACK - WV	Transmission		138.00	0.00	0.00	0.00	0	0
295	SWITCHBACK - WV	Transmission		138.00	36.20	0.00	15.00	1	0
296	TACKETT CREEK - WV	Transmission		138.00	13.09	0.00	25.00	1	0
297	TEAYS - WV	Transmission		69.00	12.00	0.00	22.40	1	0
298	TOMS FORK - WV	Transmission		46.00	0.00	0.00	0.00	0	0
299	TOMS FORK - WV	Transmission		46.00	12.00	0.00	4.69	1	0
300	TOWER 117 - WV	Transmission		69.00	0.00	0.00	0.00	0	0
301	TRAIL FORK - WV	Transmission		138.00	13.09	0.00	12.50	1	0
302	TRI-STATE - WV	Transmission		345.00	138.00	13.80	900.00	2	0
303	TRI-STATE - WV	Transmission		345.00	137.50	13.80	270.00	1	0
304	UNITED FUEL GAS COMPANY - WV	Transmission		69.00	4.00	0.00	6.25	1	0
305	UPPER BRANCH - WV	Transmission		46.00	7.20	0.00	2.01	3	0
306	URY - WV	Transmission		46.00	12.00	0.00	20.00	1	0
307	VAN - WV	Transmission		69.00	12.00	0.00	6.25	1	0
308	WARD HOLLOW - WV	Transmission		46.00	0.00	0.00	0.00	0	0
309	WEST HUNTINGTON - WV	Transmission		138.00	13.09	0.00	9.38	1	0
310	WEST HUNTINGTON - WV	Transmission		34.50	0.00	0.00	0.00	0	0
311	WHARNCLIFFE - WV	Transmission		46.00	0.00	0.00	0.00	0	0
312	WHITESTICK - WV	Transmission		46.00	12.00	0.00	22.40	1	0

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
313	WYOMING - WV	Transmission		138.00	0.00	0.00	0.00	0	0
314	TotalTransmissionSubstationMember								
315	Total								

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1		0	0.00
2		0	0.00
3		0	0.00
4		0	0.00
5	STATCAP	1	9.60
6		0	0.00
7		0	0.00
8		0	0.00
9		0	0.00
10	STATCAP	1	9.60
11		0	0.00
12		0	0.00
13		0	0.00
14		0	0.00
15		0	0.00
16	REACTOR	2	200.00
17		0	0.00
18	4000A Air-Core Reactor	3	0.00
19		0	0.00
20		0	0.00
21		0	0.00
22		0	0.00
23		0	0.00
24		0	0.00
25		0	0.00
26	STATCAP	1	9.60
27		0	0.00
28		0	0.00
29		0	0.00
30	STATCAP	1	52.80
31		0	0.00
32		0	0.00
33		0	0.00
34		0	0.00
35		0	0.00
36		0	0.00
37	Air Core Reactor	6	0.00
38	REACTOR	3	300.00
39	K06766-E100 138kV 2000A 19 Ohm Air-Core Reactor	1	0.00
40		0	0.00
41		0	0.00
42		0	0.00
43		0	0.00
44		0	0.00
45		0	0.00
46		0	0.00
47		0	0.00
48	STATCAP	1	3.59
49		0	0.00
50	STATCAP	1	14.39
51		0	0.00
52		0	0.00
53	STATCAP	1	9.60

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
54		0	0.00
55		0	0.00
56		0	0.00
57		0	0.00
58		0	0.00
59		0	0.00
60		0	0.00
61		0	0.00
62		0	0.00
63	STATCAP	1	8.10
64		0	0.00
65		0	0.00
66		0	0.00
67	STATCAP	1	57.60
68	XSLR - 0.6mH / 480A	3	0.00
69	STATCAP	1	14.39
70		0	0.00
71		0	0.00
72	STATCAP	1	52.79
73		0	0.00
74		0	0.00
75	STATCAP	1	52.79
76		0	0.00
77		0	0.00
78		0	0.00
79		0	0.00
80	STATCAP	1	26.39
81	STATCAP	2	100.80
82		0	0.00
83		0	0.00
84	STATCAP	1	172.50
85		0	0.00
86	STATCAP	1	9.60
87		0	0.00
88		0	0.00
89	XSLR - 0.6mH / 480A	3	0.00
90	STATCAP	1	0.00
91	STATCAP	2	100.80
92		0	0.00
93		0	0.00
94		0	0.00
95	STATCAP	1	14.39
96		0	0.00
97	STATCAP	1	12.00
98	XSLR - 0.6mH / 480A	3	0.00
99	STATCAP	1	0.00
100	STATCAP	1	0.00
101		0	0.00
102		0	0.00
103		0	0.00
104		0	0.00
105		0	0.00
106		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
107	STATCAP	1	28.80
108	STATCAP	1	28.80
109		0	0.00
110		0	0.00
111		0	0.00
112		0	0.00
113	STATCAP	3	888.84
114	STATCAP	1	3.59
115		0	0.00
116		0	0.00
117		0	0.00
118	STATCAP	1	0.00
119		0	0.00
120		0	0.00
121		0	0.00
122		0	0.00
123		0	0.00
124		0	0.00
125		0	0.00
126		0	0.00
127		0	0.00
128		0	0.00
129		0	0.00
130		0	0.00
131	STATCAP	1	13.19
132		0	0.00
133		0	0.00
134		0	0.00
135		0	0.00
136		0	0.00
137		0	0.00
138		0	0.00
139		0	0.00
140		0	0.00
141		0	0.00
142		0	0.00
143		0	0.00
144	STATCAP	1	10.80
145		0	0.00
146	STATCAP	1	57.60
147		0	0.00
148	REACTOR	12	807.60
149	REACTOR	12	807.60
150	REACTOR	12	807.60
151		0	0.00
152	STATCAP	1	32.40
153		0	0.00
154		0	0.00
155		0	0.00
156	STATCAP	1	3.59
157		0	0.00
158		0	0.00
159		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
160		0	0.00
161		0	0.00
162		0	0.00
163		0	0.00
164		0	0.00
165		0	0.00
166		0	0.00
167		0	0.00
168	STATCAP	1	10.80
169		0	0.00
170		0	0.00
171		0	0.00
172	STATCAP	1	28.80
173		0	0.00
174		0	0.00
175		0	0.00
176		0	0.00
177		0	0.00
178		0	0.00
179		0	0.00
180		0	0.00
181	STATCAP	1	28.80
182		0	0.00
183		0	0.00
184		0	0.00
185	STATCAP	1	14.39
186		0	0.00
187	STATCAP	1	14.40
188		0	0.00
189		0	0.00
190		0	0.00
191		0	0.00
192		0	0.00
193		0	0.00
194		0	0.00
195		0	0.00
196		0	0.00
197		0	0.00
198		0	0.00
199		0	0.00
200	STATCAP	1	9.60
201		0	0.00
202	STATCAP	1	28.80
203		0	0.00
204		0	0.00
205		0	0.00
206		0	0.00
207		0	0.00
208	STATCAP	1	12.00
209		0	0.00
210		0	0.00
211	STATCAP	1	14.40
212		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
213		0	0.00
214	STATCAP	1	9.60
215	STATCAP	1	9.60
216		0	0.00
217		0	0.00
218		0	0.00
219		0	0.00
220		0	0.00
221	STATCAP	2	52.19
222		0	0.00
223		0	0.00
224		0	0.00
225		0	0.00
226		0	0.00
227		0	0.00
228		0	0.00
229		0	0.00
230		0	0.00
231		0	0.00
232		0	0.00
233		0	0.00
234	Air Core Reactor	3	0.00
235	STATCAP	1	6,000.00
236		0	0.00
237		0	0.00
238		0	0.00
239		0	0.00
240		0	0.00
241	STATCAP	1	9.60
242		0	0.00
243		0	0.00
244		0	0.00
245	STATCAP	1	0.00
246		0	0.00
247		0	0.00
248	STATCAP	1	21.60
249		0	0.00
250	STATCAP	2	115.20
251		0	0.00
252		0	0.00
253		0	0.00
254		0	0.00
255	STATCAP	2	115.19
256		0	0.00
257		0	0.00
258		0	0.00
259		0	0.00
260		0	0.00
261		0	0.00
262		0	0.00
263		0	0.00
264		0	0.00
265		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
266		0	0.00
267	STATCAP	1	14.40
268		0	0.00
269		0	0.00
270		0	0.00
271	STATCAP	1	7.20
272		0	0.00
273	STATCAP	1	9.60
274		0	0.00
275		0	0.00
276	STATCAP	1	14.40
277		0	0.00
278		0	0.00
279		0	0.00
280		0	0.00
281		0	0.00
282		0	0.00
283		0	0.00
284		0	0.00
285	STATCAP	1	14.40
286		0	0.00
287		0	0.00
288		0	0.00
289		0	0.00
290		0	0.00
291		0	0.00
292		0	0.00
293	STATCAP	1	9.60
294	STATCAP	1	50.40
295		0	0.00
296		0	0.00
297		0	0.00
298	STATCAP	1	9.60
299		0	0.00
300	STATCAP	1	13.19
301		0	0.00
302		0	0.00
303		0	0.00
304		0	0.00
305		0	0.00
306		0	0.00
307		0	0.00
308	STATCAP	1	32.40
309		0	0.00
310	STATCAP	1	9.60
311	STATCAP	1	9.60
312		0	0.00
313	XSDR - 1.539mH / 3600A	6	0.00
314			11,411
315			11,411

Name of Respondent: Appalachian Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/09/2024	Year/Period of Report End of: 2023/ 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	[(a)] 935	6,338,836
3	Administrative and General Expenses - Operation	AEPSC	920-931	1,616,444
4	Audit Services	AEPSC	920,923	1,277,857
5	Barging	I&M	151	39,168,416
6	Civil & Political Activities and Other Svcs	AEPSC	426	914,166
7	Construction Services	AEPSC	107,108	160,567,663
8	Construction Services	KgPCo	107,108	2,111,346
9	Construction Services	OPCo	107,108	(281,721)
10	Construction Services	PSO	107,108	468,383
11	Construction Services	WPCo	107,108	258,340
12	Corp Safety & Health	AEPSC	920,923	2,255,970
13	Corporate Accounting	AEPSC	920,923	2,805,946
14	Corporate Planning & Budgeting	AEPSC	920,923	2,159,405
15	Customer Accounts Expenses	AEPSC	901-905	18,980,313
16	Distribution Expenses - Maintenance	AEPSC	590-595, 597-598	2,351,024
17	Distribution Expenses - Maintenance	KgPCo	590, 593-598	758,547
18	Distribution Expenses - Maintenance	PSO	592-595, 597	262,830
19	Distribution Expenses - Operation	AEPSC	580-584, 586-588	5,918,725
20	Distribution Expenses - Operation	KgPCo	580,583,586-588	453,186
21	Environmental Services	AEPSC	920,923	1,043,998
22	Factored Customer A/R Bad Debts	AEP Credit	426	11,027,390
23	Factored Customer A/R Expense	AEP Credit	426	5,911,049
24	Federal Affairs	AEPSC	920,923	907,052
25	Fleet and Vehicle Charges	AEP Texas	See Footnote	309,857
26	Fuel & Storeroom Services	AEPSC	152,163	10,453,682
27	Human Resources	AEPSC	920,923	5,613,269
28	Hydraulic Power Generation - Maintenance	AEPSC	541-545	908,973
29	Hydraulic Power Generation - Operation	AEPSC	535-540	3,569,070
30	Information Technology	AEPSC	920,923	10,430,958
31	Infrastructure Ops & Support	AEPSC	920,923	1,381,126
32	Legal GC/Administration	AEPSC	920,923	8,293,056
33	Materials and Supplies	KgPCo	107, 184,583,586,593,594	486,018
34	Materials and Supplies	OPCo	107, 108,154,163,184,186,562,570,571,592,930,935	10,299,776
35	Other Operating Revenues	OPCo	456	(293,736)
36	Other Power Supply Expenses	AEPSC	556, 557	7,060,448
37	Physical & Cyber Security	AEPSC	920,923	946,349
38	Reg Infrastructure Investment Planning	AEPSC	920,923	260,128
39	Research and Other Services	AEPSC	183,184,186,188	5,892,125
40	Steam Power Generation - Maintenance	AEPSC	510-514	7,047,516
41	Steam Power Generation - Operation	AEPSC	500-502,506,508	17,504,582
42	Strategy & Transformation	AEPSC	920,923	295,058
43	Supply Chain & Fleet and Property Management	AEPSC	920,923	3,835,514
44	Tax Services	AEPSC	920,923	1,297,917
45	Transmission Expenses - Maintenance	AEPSC	568-573	6,276,817
46	Transmission Expenses - Operation	AEPSC	560-563,566,567,920,923	20,532,865

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)
47	Treasury & Risk	AEPSC	920,923	5,583,769
48	Urea	KPCo	154	477,315
49	Urea	WPCo	154	954,629
50	Use of Jointly Owned Facility	WVTCo	589	293,031
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Building and Property Leases	AEPSC	454	3,868,409
22	Central Machine Shop	AEP Texas	107,108,592	289,201
23	Central Machine Shop	I&M	107,108,163,500,506,512,513,524,530,531,544,592	2,497,038
24	Central Machine Shop	PSO	107, 108,500,511-514,531,546,549,553	1,040,351
25	Central Machine Shop	SWEPCo	107, 108,500,512,513	541,407
26	Central Machine Shop	WPCo	107, 108,500,506,512-514	1,733,980
27	Construction Services	KgPCo	107, 108	915,085
28	Construction Services	KPCo	107, 108	489,986
29	Construction Services	SWEPCo	107, 108	377,233
30	Construction Services	WPCo	107, 108	556,063
31	Construction Services	WVTCo	107, 108	926,586
32	Distribution Expenses - Maintenance	KgPCo	593-596,598	454,189
33	Distribution Expenses - Maintenance	PSO	593-595	392,598
34	Distribution Expenses - Maintenance	SWEPCo	593	839,204
35	Distribution Expenses - Maintenance	WPCo	593, 597,598	263,649
36	Expenses of Nonutility Operations	I&M	417	5,016,709
37	Facility Rent	WVTCo	454	2,704,221
38	Fleet and Vehicle Charges	AEP Texas	(b) See Footnote	310,287
39	Fleet and Vehicle Charges	AEPSC	See Footnote	5,743,624
40	Materials and Supplies	AEP Texas	154	760,076
41	Materials and Supplies	OKTCo	154	414,070
42	O&M Services for Jointly Owned Facility - Sporn	AEP Generation Resources	500,506,925,926	(1,641,392)
43	Other Operating Revenues	OPCo	456	(998,126)
44	Other Operating Revenues	PSO	456	(339,048)
45	Other Operating Revenues	SWEPCo	456	(254,656)
46	Service and Administration Fees	Appalachian Rate Relief Fund	456	290,150
47	Urea	KPCo	154	954,629
48	Urea	WPCo	154	898,363
49	Use of Jointly Owned Facility	APTCo	454	1,930,882
50	Use of Jointly Owned Facility	WVTCo	454	836,079
42				

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FOOTNOTE DATA

(a) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Certain managerial and professional services provided by AEPSC are allocated among multiple affiliates. The costs of the services are billed on a direct-charge basis, whenever possible. Costs incurred to perform services that benefit more than one company are allocated to the benefiting companies using one of 80 FERC accepted allocation factors. The allocation factors used to bill for services performed by AEPSC are based upon formulae that consider factors such as number of customers, number of employees, number of transmission pole miles, number of invoices and other factors. The data upon which these formulae are based is updated monthly, quarterly, semi-annually or annually, depending on the particular factor and its volatility. The billings for services are made at cost and include no compensation for a return on investment.

(b) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Costs 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.