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

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
SWEPCO	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 SWEPCO		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, Ohio 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 02 Title Assistant Controller	03 Signature Jeffrey W. Hoersdig	04 Date Signed (Mo, Da, Yr) 04/09/2024

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: SWEPCO	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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
47	**Purchased Power**	326	
48	**Transmission of Electricity for Others**	328	
49	**Transmission of Electricity by ISO/RTOs**	331	
50	**Transmission of Electricity by Others**	332	
51	**Miscellaneous General Expenses-Electric**	335	
52	**Depreciation and Amortization of Electric Plant (Account 403, 404, 405)**	336	
53	**Regulatory Commission Expenses**	350	
54	**Research, Development and Demonstration Activities**	352	
55	**Distribution of Salaries and Wages**	354	
56	**Common Utility Plant and Expenses**	356	
57	**Amounts included in ISO/RTO Settlement Statements**	397	
58	**Purchase and Sale of Ancillary Services**	398	
59	**Monthly Transmission System Peak Load**	400	
60	**Monthly ISO/RTO Transmission System Peak Load**	400a	
61	**Electric Energy Account**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	
64	**Hydroelectric Generating Plant Statistics**	406	
65	**Pumped Storage Generating Plant Statistics**	408	
66	**Generating Plant Statistics Pages**	410	
66.1	**Energy Storage Operations (Large Plants)**	414	
66.2	**Energy Storage Operations (Small Plants)**	419	
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☐ No annual report to stockholders is prepared		
	Page 2		

Name of Respondent: SWEPCO	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, Assistant Controller

212 East Sixth StreetTulsa, Oklahoma 74119

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of DelawareJune 29, 1912

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.

Public Utility engaged in generating, purchasing, transmitting, distributing and selling electric energy.Qualified to do business in the states of Arkansas, Louisiana, Oklahoma and Texas. The Company owns transmission facilities but provides no electric service at retail in Oklahoma.

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

(2)
☑ No

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

CONTROL OVER RESPONDENT

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

American Electric Power Company, Inc., a registered holding company, owns 100% of the Respondent's outstanding shares of Common Stock.

Name of Respondent: SWEPCO	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	Southwest Arkansas	Aid in Right of Way	100%	
2		Acquisition		
3	Dolet Hills Lignite Company	Lignite Mine Operator	100%	
4	Sabine Mining COmpany	Lignite Mine Operatore		1
5	Oxbow Lignite Company, LLC	Lignite Mine Reserves	50%	2
6	Mutual Energy SWEPCO, LLC	Energy Company	100%	
7	Footnote 1-			
8	Accounting guidance for Variable Interest			
9	Entities - Respondent contracts to			
10	Purchase 100% of the lignite mined			
11	Footnote 2-			
12	Ownership of the Oxbow Mining Company is held			
13	Jointly with Cleco Power Company LLC			

Name of Respondent: SWEPCO	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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Name of Respondent: SWEPCO	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: OfficerTitle

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

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 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	$ 14,850	$ 14,850	$ 14,850	$ 14,85	$ 14,850	$ 14,850	$ 14,850
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	**$ 114,455**	**$ 73,170**	**$ 109,767**	**$ 170,900**	**$ 87,482**	**$ 359,384**	**$ 550,866**

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: SWEPCO	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	Paul Chodak, Vice President	Columbus. Ohio		
2	David M. Feinberg, Secretary and Vice President	Columbus, Ohio		
3	Ann P. Kelly, Chief Financial Officer and Vice President	Columbus, Ohio		
4	Therace M. Risch, Vice President	Columbus, Ohio		
5	Julia A.Sloat, Chair of the Board and Chief Executive Officer	Columbus, Ohio		
6	Toby L. Thomas, Vice President	Columbus, Ohio		
7	Phillip R. Ulrich, Vice President	Columbus, Ohio		
8	Christian T. Beam, Vice President	Columbus, Ohio		
9	Peggy I. Simmons, Vice President	Columbus, Ohio		
10	Rajagopalan, Sundararajan, Executive Vice President	Columbus, Ohio		
11	D Brett. Mattison, President and Chief Operating Officer	Columbus, Ohio		
12	Antonio P. Smyth, Vice President	Columbus, Ohio		
13	Charles E. Zebula, Chief Financial Officer, Vice President	Columbus, Ohio		
14	The Respondent does not have an Executive Committee.			

Name of Respondent: SWEPCO	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	Rate Schedule 119	ER19-159-000
2	Rate Schedule 125	ER18-2374-000
3	Rate Schedule 126	ER18-2349-000
4	Rate Schedule 127	ER18-1824-000
5	Rate Schedule 128	ER18-1774-000
6	Rate Schedule 129	ER19-171-000
7	SPP FERC Electric Tariff 6th Revision Vol. No. 1	ER07-1069
8	Addendum 4 to Attachment H, Parts 1 and 2	
9	SPP FERC Electric Tariff Vol. No. 1	ER18-195
10	Attachment H, Parts 1 and 2	

Name of Respondent: SWEPCO	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 (Checked by default - Not explicitly defined)

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	20090526-5302	05/26/2009	ER09-1198-000	AEP SPP 2009 Trans FR Update	SPP OATT Att. H-4
2	20090831-5276	08/31/2009	ER09-1198-000	Errata of 2009 Update	SPP OATT Att. H-4
3	20100525-5109	05/25/2010	ER10-355-000	AEP SPP 2010 Trans FR Update	SPP OATT Att. H-4
4	20110928-5123	09/28/2011	ER11-4671-000	AEP SPP 2011 Trans FR Update	SPP OATT Att. H-4
5	20111221-5253	12/21/2011	ER11-1069-000	Errata of 2011 Update	SPP OATT Att. H-4
6	20120523-5024	05/23/2012	ER07-1069-000	AEP SPP 2012 Trans FR Update	SPP OATT Att. H-4
7	20130910-3004	05/24/2013	ER13-1606-000	AEP SPP 2013 Trans FR Update	SPP OATT Att. H-4
8	20141208-5379	12/08/2014	ER07-1069-000	AEP SPP 2014 Trans FR Update	SPP OATT Att. H-4
9	20150604-5186	05/14/2015	ER07-1069-000	AEP SPP 2015 Trans FR Update	SPP OATT Att. H-4
10	20160523-5233	05/23/2016	ER07-1069-000	AEP SPP 2016 Trans FR Update	SPP OATT Att. H-4
11	20160630-5407	06/30/2016	ER07-1069-000	Errata of 2016 Update	SPP OATT Att. H-4
12	20170525-5337	05/25/2017	ER07-1069-000	AEP SPP 2017 Trans FR Update	SPP OATT Att. H-4
13	20171031-5311	10/31/2017	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
14	20180525-5243	05/25/2018	ER18-195-000	AEP SPP 2018 Trans FR Update	SPP OATT Att. H-4
15	20181101-5217	11/01/2018	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
16	20181213-5182	12/13/2018	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
17	20190528-5199	05/28/2019	ER18-195-000	AEP SPP 2019 Trans FR Update	SPP OATT Att. H-4
18	20190723-5114	07/23/2019	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
19	20190724-5030	07/24/2019	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
20	20190731-5132	07/31/2019	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
21	20191031-5138	10/31/2019	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
22	20200526-5243	05/26/2020	ER18-195-000	AEP SPP 2020 Trans FR Update	SPP OATT Att. H-4
23	02200609-5107	06/09/2020	ER18-195-000	AEP SPP 2020 Trans FR Update	SPP OATT Att. H-4
24	20201102-5246	11/02/2020	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
25	20210525-5227	05/25/2021	ER18-195-000	AEP SPP 2021 Trans FR Update	SPP OATT Att. H-4
26	20211101-5258	11/01/2021	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
27	20220525-5165	05/25/2022	ER18-195-000	AEP SPP 2022 Trans FR Update	SPP OATT Att. H-4
28	20220602-5172	06/02/2022	ER18-195-000	AEP SPP 2022 Trans FR Update	SPP OATT Att. H-4
29	20221101-5102	11/01/2022	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4
30	20230525-5144	05/25/2023	ER18-195-000	AEP SPP 2023 Trans FR Update	SPP OATT Att. H-4
31	20231031-5363	10/31/2023	ER18-195-000	AEP SPP OATT Projected Revenue Requirement	SPP OATT Att. H-4

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Name of Respondent: SWEPCO	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)
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Name of Respondent: SWEPCO	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.

By Company-Community	Renewal Date/Auto Renewal	Consideration
Zwolle, Sabine Parish, LA	6/12/2048	3% franchise fee
Red Lick, TX	12/31/2049	$0.000679 per kwh used
Fisher, LA	8/11/2048	3% franchise fee
New London, TX	12/31/2053	$0.003216 per kwh used within the boundaries of the city limits
Powhatan, LA	9/8/2048	3% franchise fee

None

None

None

None

SWEPCo issued a Senior Unsecured Notes, Series P of $350,000,000 on March 30, 2023, maturing on April 1, 2033. FERC Authority: ES21-41-000

None

Wage agreements, effective September 1, 2023, resulted in general increase of 3.5% settlement for certain represented employees.

None

None

Not Used

Julia A. Sloat elected as Chair of the Board effective on 01-01-2023
Brett D Mattison, elected as President, Chief Operating Officer and Director effective on 01-04-2023
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 effective on 05-09-2023
Kate, Sturgess elected as Controller effective on 05-09-2023
Joseph M. Buonaiuto resigned as Chief Accounting Officer effective on 05-08-2023
Joseph M. Buonaiuto resigned as Controller effective on 05-08-2023
Sundararajan Rajagopalan, resigned as Director efffective on 04-05-2023
Peggy I. Simmons elected as director 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
Paul Chodak, III resigned as Director effective on 07-26-2023
Scott N. Smith resigned as Vice President effective on 07-14-2023
III Paul, Chodak resigned as Vice President effective on 08-18-2023
Eric J James, resigned as Vice President effective on 08-18-2023
Ann P Kelly, resigned as Vice President, Chief Financial Officer & Director effective on 09-29-2023
Mark J Leskowitz, resigned as Vice President effective on 08-18-2023
Daniel E. Mueller resigned as Assistant Vice President - Tax effective on 08-18-2023
Scott P. Moore resigned as Vice President effective on 08-18-2023
Thomas D Presthus, resigned as Vice President effective on 08-18-2023
Therace M. Risch resigned as Vice President effective on 08-18-2023
Scott N Smith, resigned as Vice President effective on 07-14-2023
Charles E. Zebula resigned as Vice President effective on 08-18-2023
Toby L. Thomas resigned as Director effective on 07-26-2023
Toby L. Thomas resigned as Vice President effective on 08-18-2023
Phillip R. Ulrich resigned as Vice President effective on 08-18-2023
Ann P. Kelly resigned as Vice President, Chief Financial Officer and Director effective on 09-29-2023
Charles E Zebula elected as Director, Chief Financial Officer and Vice President effective on 10/03/2023

Proprietary capital ratio exceeds 30%

Name of Respondent: SWEPCO	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	11,137,333,923	11,404,522,259
3	Construction Work in Progress (107)	200	560,906,375	372,772,642
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		11,698,240,298	11,777,294,901
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	3,036,989,283	3,419,289,601
6	Net Utility Plant (Enter Total of line 4 less 5)		8,661,251,015	8,358,005,300
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)		8,661,251,015	8,358,005,300
15	Utility Plant Adjustments (116)		(171,735,513)	(89,761,839)
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		87,516,842	1,887,251
19	(Less) Accum. Prov. for Depr. and Amort. (122)		63,743,826	(65)
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	12,189,280	12,199,879
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		1,025,469	1,025,469
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)		57,435,760	47,891,091
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)		94,423,525	63,003,755
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		2,419,627	4,161,626
36	Special Deposits (132-134)		1,287,557	16,504,298
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		37,400,573	37,133,018
41	Other Accounts Receivable (143)		8,155,387	11,046,796
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		308	34,184
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		43,843,322	61,529,721
45	Fuel Stock (151)	227	[a]110,249,718	64,682,162
46	Fuel Stock Expenses Undistributed (152)	227	3,582,634	2,463,830
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	[b]84,172,252	85,132,769
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	365,565	2,725,866
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	1,700	1,700
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		30,052,241	36,695,215
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		1,551,112	1,699,945
61	Accrued Utility Revenues (173)		42,982,873	48,996,691
62	Miscellaneous Current and Accrued Assets (174)		(9,143)	(9,143)
63	Derivative Instrument Assets (175)		11,598,372	16,439,806
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)		377,653,482	389,170,115
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		21,983,823	21,474,923
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	1,329,555,443	1,282,122,376
73	Prelim. Survey and Investigation Charges (Electric) (183)		5,173,575	2,208,444
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		4,300	4,300
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	115,766,894	69,649,648
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		4,148,378	4,748,153
82	Accumulated Deferred Income Taxes (190)	234	412,885,884	[c]358,218,566
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		1,889,518,297	1,738,426,411
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		10,851,110,806	10,458,843,742
		Page 110-111		

Name of Respondent: SWEPCO	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: FuelStock

Formula Rate uses 13 month average.

(b) Concept: PlantMaterialsAndOperatingSupplies

Formula Rate uses 13 month average. Production materials and supplies are identified by a query of the general ledger system.

(c) Concept: AccumulatedDeferredIncomeTaxes

Formula Rate uses 13 month average.

Line 17 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Acc Def Income Taxes - Federal - Hdg-CF-Int Rate	0	-
Non Utility Items - 190.2	626557	-6486
SFAS 109-Regulatory Assets - 190.3, 190.4 & 190.6	190302081	204754688
SFAS 133	-	-
Accu Def Income Taxes Pension-OCI	1468371	1306877
Total	192397009	206055079

Line 18

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

Balance at Beginning of Year	358218566
(Less) Amounts Debited to:	
(a) Account 410.1	-36069739
(b) Account 410.2	-3161348
(c) 1823/254/219/129/427	-17369657
(Plus) Amounts Credited to:	
(a) Account 411.1	77078987
(b) Account 411.2	2528305
(c) 1823/254/219/129/427	31660769
Balance at End of Year	412885883

Name of Respondent: SWEPCO	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	66,240	66,240
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	1,492,147,009	1,442,145,410
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	437	
11	Retained Earnings (215, 215.1, 216)	118	2,234,651,756	2,190,847,304
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	46,704,257	45,220,224
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(3,417,071)	(4,211,969)
16	Total Proprietary Capital (lines 2 through 15)		3,770,151,754	3,674,067,209
17	**LONG-TERM DEBT**			
18	Bonds (221)	256		
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	3,675,000,000	3,325,000,000
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		6,076,501	5,941,480
24	Total Long-Term Debt (lines 18 through 23)		3,668,923,499	3,319,058,520
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		140,930,229	143,340,592
27	Accumulated Provision for Property Insurance (228.1)			745,200
28	Accumulated Provision for Injuries and Damages (228.2)		114,682	274,628
29	Accumulated Provision for Pensions and Benefits (228.3)		41,246,894	27,665,926
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		24,880,007	9,878,255
32	Long-Term Portion of Derivative Instrument Liabilities		1,230,719	
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		148,020,016	158,989,379
35	Total Other Noncurrent Liabilities (lines 26 through 34)		356,422,547	340,893,980
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		198,055,606	212,249,363
39	Notes Payable to Associated Companies (233)		88,726,336	310,656,994
40	Accounts Payable to Associated Companies (234)		90,757,307	136,287,585
41	Customer Deposits (235)		72,470,328	65,371,614
42	Taxes Accrued (236)	262	27,290,089	35,703,239
43	Interest Accrued (237)		39,887,705	34,795,018
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		7,033,579	8,543,821
48	Miscellaneous Current and Accrued Liabilities (242)		221,106,896	204,579,550
49	Obligations Under Capital Leases-Current (243)		20,011,366	13,671,720

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)		15,609,127	1,374,224
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		1,230,719	
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)		779,717,620	1,023,233,128
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)			
57	Accumulated Deferred Investment Tax Credits (255)	266	186,614	434,367
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	63,662,592	41,456,591
60	Other Regulatory Liabilities (254)	278	617,443,904	612,665,725
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	46,703,381	48,904,159
63	Accum. Deferred Income Taxes-Other Property (282)		1,102,280,087	1,049,455,685
64	Accum. Deferred Income Taxes-Other (283)		445,618,808	[a]348,674,379
65	Total Deferred Credits (lines 56 through 64)		2,275,895,386	2,101,590,906
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		10,851,110,806	10,458,843,743

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther
Formula Rate uses 13 month average.

Name of Respondent: SWEPCO	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	2,034,978,853	2,435,089,872			2,034,978,853	2,435,089,872				
3	Operating Expenses											
4	Operation Expenses (401)	320	996,552,378	1,423,728,545			996,552,378	1,423,728,545				
5	Maintenance Expenses (402)	320	159,681,387	148,782,630			159,681,387	148,782,630				
6	Depreciation Expense (403)	336	293,761,539	289,223,073			293,761,539	289,223,073				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	2,162,759	1,997,322			2,162,759	1,997,322				
8	Amort. & Depl. of Utility Plant (404-405)	336	32,294,926	29,143,882			32,294,926	29,143,882				
9	Amort. of Utility Plant Acq. Adj. (406)	336										
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		15,557,778	4,954,396			15,557,778	4,954,396				
13	(Less) Regulatory Credits (407.4)		72,000	72,000			72,000	72,000				
14	Taxes Other Than Income Taxes (408.1)	262	135,116,450	126,830,017			135,116,450	126,830,017				
15	Income Taxes - Federal (409.1)	262	(75,819,535)	(37,907,894)			(75,819,535)	(37,907,895)				
16	Income Taxes - Other (409.1)	262	3,257,079	(1,724,002)			3,257,079	(1,724,002)				

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	278,042,353	326,568,555			278,042,353	326,568,555				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	221,287,357	308,596,438			221,287,357	308,596,438				
19	Investment Tax Credit Adj. - Net (411.4)	266	(247,752)	(530,982)			(247,752)	(530,982)				
20	(Less) Gains from Disp. of Utility Plant (411.6)											
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)		49	207			49	207				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		4,316,391	3,701,231			4,316,391	3,701,231				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,623,316,348	2,006,098,128			1,623,316,347	2,006,098,127				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		411,662,505	428,991,744			411,662,506	428,991,745				
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)			141								
35	Nonoperating Rental Income (418)		318	867								
36	Equity in Earnings of Subsidiary Companies (418.1)	119	1,484,033	1,393,940								
37	Interest and Dividend Income (419)		17,923,242	17,354,919								
38	Allowance for Other Funds Used During Construction (419.1)		11,501,698	4,918,057								
39	Miscellaneous Nonoperating Income (421)		939,056	772,113								
40	Gain on Disposition of Property (421.1)		160,451	12,350								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		32,008,799	24,452,105								
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)		368,029	62,897								
44	Miscellaneous Amortization (425)		75	25								
45	Donations (426.1)		720,321	9,053,468								
46	Life Insurance (426.2)											
47	Penalties (426.3)		36,290	72,699								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		712,351	1,010,930								
49	Other Deductions (426.5)		96,924,557	25,890,660								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		98,761,623	36,090,680								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	10,317	10,308								
53	Income Taxes-Federal (409.2)	262	(16,666,199)	(4,520,013)								
54	Income Taxes-Other (409.2)	262	(2,252,187)	(30,210)								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	3,161,348	2,072,277								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	2,528,305	1,574,176								
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(18,275,026)	(4,041,814)								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(48,477,798)	(7,596,761)								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		132,204,834	118,468,048								
63	Amort. of Debt Disc. and Expense (428)		3,041,189	2,843,877								
64	Amortization of Loss on Reaquired Debt (428.1)		274,114	274,114								
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)		7,940,310	4,864,538								
68	Other Interest Expense (431)		9,200,325	9,162,861								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		9,764,551	4,278,557								

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)		142,896,221	131,334,881								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		220,288,485	290,060,102								
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	0									
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		220,288,485	290,060,102								
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Name of Respondent: SWEPCO	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		2,190,847,304	2,007,181,143
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	Adj to Retained Earnings			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		218,804,453	288,666,161
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	$18 par value - 7,536,640 shares outstanding		(175,000,001)	105,000,000
30.2	Total Dividends Decl - Common Stk (438)			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(175,000,001)	105,000,000
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,234,651,756	2,190,847,304
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,234,651,756	2,190,847,304
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		45,220,224	43,826,284
50	Equity in Earnings for Year (Credit) (Account 418.1)		1,484,033	1,393,940
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)		46,704,257	45,220,224

Name of Respondent: SWEPCO	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)	220,288,485	290,060,102
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	328,219,224	320,364,278
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Regulatory Debits and Credits (Net)	15,485,778	4,882,396
8	Deferred Income Taxes (Net)	57,388,039	18,470,218
9	Investment Tax Credit Adjustment (Net)	(247,752)	(530,982)
10	Net (Increase) Decrease in Receivables	20,425,210	(26,230,204)
11	Net (Increase) Decrease in Inventory	(48,305,188)	(13,317,297)
12	Net (Increase) Decrease in Allowances Inventory	2,360,301	(2,660,274)
13	Net Increase (Decrease) in Payables and Accrued Expenses	(20,111,160)	64,496,921
14	Net (Increase) Decrease in Other Regulatory Assets	112,009,842	(83,377,826)
15	Net Increase (Decrease) in Other Regulatory Liabilities	5,477,334	(3,417,087)
16	(Less) Allowance for Other Funds Used During Construction	11,501,698	4,918,057
17	(Less) Undistributed Earnings from Subsidiary Companies	1,484,033	1,393,940
18	Other (provide details in footnote):		
18.1	[(a)] Other (provide details in footnote):	(3,648,586)	(21,004,657)
18.2	Mark-to-Market of Risk Management Contracts	19,076,334	(6,232,496)
18.3	Impairment of Long-Lived Assets	85,605,840	
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	781,037,970	535,191,095
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(798,841,089)	(594,751,454)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	(3,033)	
30	(Less) Allowance for Other Funds Used During Construction	(11,501,698)	(4,918,057)
31	Other (provide details in footnote):		
31.1	Acquired Assets	(849,735)	(658,466,665)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(788,192,159)	(1,248,300,062)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	[(b)] 1,436,933	986,915
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		

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)
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	Insurance Receivable	382,369	
53.2	Contribution In Aid of Construction Proceeds	2,934,698	3,981,277
53.3	(Increase) Decrease in Other Special Deposits	(9,484)	996,053
53.4	Notes Receivable from Associated Companies		153,842,244
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(783,447,643)	(1,088,493,573)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	350,000,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
64.2	Long Term Issuances Costs	(3,215,762)	(25,000)
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Proceeds on Capital Leaseback	812,495	537,236
67.2	Notes Payable to Associated Companies - Issued		310,656,994
67.3	Capital Contributions from Parent	50,001,599	350,001,429
70	Cash Provided by Outside Sources (Total 61 thru 69)	397,598,331	661,170,659
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Notes Payable to Associated Companies - Retired	(221,930,658)	
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(175,000,000)	(105,000,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	667,673	556,170,659
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)	(1,741,999)	2,868,182
88	Cash and Cash Equivalents at Beginning of Period	4,161,626	1,293,444
90	Cash and Cash Equivalents at End of Period	2,419,627	4,161,626
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Name of Respondent: SWEPCO	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: OtherAdjustmentsToCashFlowsFromOperatingActivitiesDescription

	2023 Cash Flow Incr / (Decr)	2022 Cash Flow Incr / (Decr)
Utility Plant, Net	$ (38,501,686)	$ (22,273,783)
Property and Investments, Net	1,567,988	24,831,635
Margin Deposits	15,226,225	(7,560,333)
Prepayments	992,423	(7,085,688)
Accrued Utility Revenues, Net	6,013,818	(17,453,463)
Unamortized Debt Expense	2,248,363	2,171,369
Other Deferred Debits, Net	(53,014,670)	(25,523,916)
Other Comprehensive Income, Net	187,375	(84,492)
Unamortized Discount/Premium on Long-Term Debt	323,479	341,783
Accumulated Provisions - Misc	12,597,321	6,080,062
Current and Accrued Liabilities, Net	21,198,913	36,667,827
Other Deferred Credits, Net	27,511,865	(11,115,657)
Total	**$ (3,648,586)**	**$ (21,004,656)**

(b) Concept: ProceedsFromDisposalOfNoncurrentAssets

	2023 Cash Flow Incr / (Decr)	2022 Cash Flow Incr / (Decr)
Longview Ops Reserve 138kV Station	$ —	$ 636,327
Stonewall Substation	724,297	
Sales of Meters	29,417	6,683
Sales of Transformers	683,219	342,992
Total	**$ 1,436,933**	**$ 986,002**

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

NOTES TO FINANCIAL STATEMENTS

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

INDEX OF NOTES TO FINANCIAL STATEMENTS

GLOSSARY OF TERMS FOR NOTES

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

Term	Meaning
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 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.
ALJ	Administrative Law Judge.
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.
APSC	Arkansas Public Service Commission.
ARO	Asset Retirement Obligations.
ASU	Accounting Standards Update.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CWIP	Construction Work in Progress.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
Energy Supply	AEP Energy Supply LLC, a nonregulated holding company for AEP's competitive generation, wholesale and retail businesses, and a wholly-owned subsidiary of AEP.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary. I&M engages in the generation, transmission and distribution of electric power to retail customers in northern and eastern Indiana and southwestern Michigan.
IRS	Internal Revenue Service.
ITC	Investment Tax Credit.
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.
LPSC	Louisiana Public Service Commission.

Term	Meaning
Maverick	Maverick, part of the North Central Wind Energy Facilities, consists of 287 MWs of wind generation in Oklahoma.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NCWF	North Central Wind Energy Facilities, a joint PSO and SWEPCo project, which includes three Oklahoma wind facilities totaling approximately 1,484 MWs of wind generation.
NOL	Net operating losses.
NOLC	Net operating loss carryforwards.
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.
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.
PUCT	Public Utility Commission of Texas.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
ROE	Return on Equity.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SPP	Southwest Power Pool regional transmission organization.
Sundance	Sundance, acquired in April 2021 as part of the North Central Wind Energy Facilities, consists of 199 MWs of wind generation in Oklahoma.
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 the panhandle of Texas, northwestern Louisiana and western Arkansas.
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.
Traverse	Traverse, part of the North Central Wind Energy Facilities, consists of 998 MWs of wind generation in Oklahoma.
Turk Plant	John W. Turk, Jr. Plant, a 650 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
Term	**Meaning**
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary. WPCo provides electric service to retail customers in northern West Virginia.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, SWEPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 548,000 retail customers in its service territory in northeastern and the panhandle of Texas, northwestern Louisiana and western Arkansas. SWEPCo sells electric power at wholesale to other utilities, municipalities and electric cooperatives.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

SWEPCo's rates are regulated by the FERC and the APSC, LPSC and PUCT. The FERC also regulates SWEPCo'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. SWEPCo'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 SWEPCo 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 APSC, LPSC and PUCT regulate all of the retail distribution operations and rates of SWEPCo's retail public utility subsidiaries on a cost basis. The APSC, LPSC and PUCT also regulate the retail generation/power supply operations and rates.

The FERC also regulates SWEPCo'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. Bundled retail transmission rates are regulated by the APSC, LPSC and PUCT.

In addition, the FERC regulates the Operating Agreement and TCA, all of which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. See Note 15 - Related Party Transactions for additional information.

Basis of Accounting

SWEPCo's accounting is subject to the requirements of the APSC, LPSC, PUCT 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 accounting for transactions from Sabine Mining Company as a nonaffiliated company rather than consolidating the entity in accordance with the accounting guidance for "Variable Interest Entities."
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of finance lease payments as operating activities instead of financing activities.
- The classification of gains/losses from disposition of allowances as utility operating expenses rather than as operating revenues.
- The classification of SPP purchases as operation expenses instead of a reduction in revenue.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.
- The presentation of finance leased assets and their associated accumulated amortization as a single amount instead of as separate amounts.
- The classification of factored accounts receivable expense as a nonoperating expense instead of as an operating expense.
- The presentation of over/under fuel recovery in revenue rather than as a component 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 accrued unbilled revenue as a current and accrued asset rather than netted against accounts payable for affiliated companies.
- 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 plant impairment in utility plant adjustments rather than in property, plant and equipment.
- The classification of plant impairment in utility plant adjustments rather than in property, plant and equipment - accumulated 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 unrecovered plant costs as accumulated depreciation instead of regulatory assets.
- The classification of rents receivable as rents receivable instead of customer accounts receivable.
- The classification of Non-Service Cost Components of Net Periodic Benefit Cost as Operating Expense instead of Other Income (Expense).
- The classification of operating lease assets as Utility Plant rather than as a noncurrent asset.
- The presentation of obligations under finance and operating leases as a single amount in Obligations Under Capital Leases rather than as separate items.
- The classification of certain expenses in operating income rather than operating expenses.
- The classification of interest on regulated finance leases as operating expense instead of Other Income (Expense).
- The classification of cloud computing implementation costs as Utility Plant rather than as a noncurrent asset.
- The classification of the amortization of certain regulatory assets as regulatory debits and credits rather than depreciation and amortization.
- The presentation of certain regulatory balances as regulated liabilities instead of regulated assets.

Accounting for the Effects of Cost-Based Regulation

SWEPCo'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,	(in millions)	
Cash was Paid (Received) for:		
Interest (Net of Capitalized Amounts)	$ 123.5	$ 125.5
Income Taxes (Net of Refunds)	(42.4)	(36.2)
Sale of Transferable Tax Credits	(41.4)	—
Noncash Acquisitions Under Finance Leases	7.1	3.6
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	63.7	105.6

Special Deposits

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

Inventory

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

Accounts Receivable 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, SWEPCo 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 SWEPCo. 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 14 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 SWEPCo. The assessment is performed separately for SWEPCo, which inherently contemplates any differences in geographical risk characteristics for the allowance for uncollectible accounts.

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

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

Concentrations of Credit Risk and Significant Customers

SWEPCo does not have any significant customers that comprise 10% or more of its operating revenues for the years ended December 31, 2023 and 2022.

SWEPCo monitors credit levels and the financial condition of its customers on a continuous basis to minimize credit risk. The APSC, LPSC and PUCT 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

SWEPCo records renewable energy credits (RECs) at cost. SWEPCo 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 costs.

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.

Investment in Subsidiary Companies

SWEPCo has two wholly-owned subsidiaries, DHLC, which was engaged in lignite-mining operations until it's closure in December 2021 and Southwest Arkansas Utilities Corporation, which is engaged in right of way acquisition. Investment in the net assets of DHLC is carried at cost plus equity in its undistributed earnings since acquisition. Investment in the net assets of Southwest Arkansas Utilities Corporation is carried at cost.

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

SWEPCo 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, wind farms and certain coal-mining facilities. AROs are computed as the present value of the estimated costs associated with the future retirement of an asset and are recorded in the period in which the liability is incurred. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be decommissioned, inflation, and discount rate, which may change significantly over time. The estimated costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. SWEPCo 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 SWEPCo plans to use their facilities indefinitely. The retirement obligation would only be recognized if and when SWEPCo 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 trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes.

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

Deferred Fuel Costs

The cost of 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 incorporated into the development of future fuel rates billed to or refunded to customers. The amount of an over-recovery or under-recovery can also be affected by actions of the APSC, LPSC and PUCT. On a routine basis, the APSC, LPSC and PUCT review and/or audit SWEPCo'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. SWEPCo 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, non-existent or not applicable to merchant operations, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

SWEPCo'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

SWEPCo recognizes revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. SWEPCo 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. In accordance with the APSC's, LPSC's and PUCT's regulatory treatment, SWEPCo does not include the fuel portion in unbilled revenue, but rather recognizes such revenues when billed to customers.

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 SWEPCo in the fourth quarter of each calendar year and a final annual true-up is recognized by SWEPCo 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 17 - 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 SPP. SWEPCo also purchases power from SPP 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 SPP, 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, SWEPCo records expenses when purchased electricity is received and when expenses are incurred. SWEPCo defers unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

SWEPCo 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. SWEPCo 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.

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

SWEPCo 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 the balance sheets as Derivative Instrument Assets or Liabilities, as appropriate, and on the statements of income in Operating Revenues. SWEPCo includes realized gains and losses on marketing and risk management transactions 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 SWEPCo 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, SWEPCo 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 10 for additional information.

Maintenance

SWEPCo expenses maintenance costs as incurred. If it becomes probable that SWEPCo 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. SWEPCo defers costs above the level included in base rates and amortizes those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment and Production Tax Credits

SWEPCo 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.

SWEPCo 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. Alternatively, PTCs reduce income tax expense as they are earned. PTCs are earned when electricity is produced.

Transferable tax credits established by the IRA are accounted for in accordance with the accounting guidance for "Income Taxes" by SWEPCo. Proceeds from sales of transferable tax credits are included as a component of Operating Activities on the statement of cash flows and presented as gross within the Supplementary Cash Flow Information.

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

Excise Taxes

As an agent for some state and local governments, SWEPCo collects from customers certain excise taxes levied by those state or local governments on customers. SWEPCo 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

SWEPCo participates in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. Substantially all SWEPCo employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. SWEPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees. SWEPCo is allocated a proportionate share of benefit costs and account for their participation in these plans as multiple-employer plans. See Note 8 - 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, 2022 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 SWEPCo's business. The following standard will impact SWEPCo'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

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

4. RATE MATTERS

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

2012 Texas Base Rate Case

In 2012, SWEPCo filed a request with the PUCT to increase annual base rates primarily due to the completion of the Turk Plant. In 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determined that the Turk Plant's Texas jurisdictional capital cost cap established in a previous Certificate of Convenience and Necessity case also limited SWEPCo's recovery of AFUDC in addition to limits on its recovery of cash construction costs.

Upon rehearing in 2014, the PUCT reversed its initial ruling and determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result, SWEPCo reversed $114 million of a previously recorded regulatory disallowance in 2013. In 2017, the Texas District Court upheld the PUCT's 2014 order and intervenors filed appeals with the Texas Third Court of Appeals.

In August 2021, the Texas Third Court of Appeals reversed the Texas District Court judgment affirming the PUCT's order on AFUDC, concluding that the language of the PUCT's original 2008 order intended to include AFUDC in the Texas jurisdictional capital cost cap, and remanded the case to the PUCT for future proceedings. In November 2021, SWEPCo and the PUCT submitted Petitions for Review with the Texas Supreme Court. In October 2022, the Texas Supreme Court denied the Petitions for Review submitted by SWEPCo and the PUCT. In December 2022, SWEPCo and the PUCT filed requests for rehearing with the Texas Supreme Court. In June 2023, the Texas Supreme Court denied SWEPCo's request for rehearing and the case was remanded to the PUCT for future proceedings. In October 2023, SWEPCo filed testimony with the PUCT in the remanded proceeding recommending no refund or disallowance.

On December 14, 2023, the PUCT approved a preliminary order stating the PUCT will not address SWEPCo's request that would allow the PUCT to find cause to allow SWEPCo to exceed the Texas jurisdictional capital cost cap in the current remand proceeding. As a result of the PUCT's approval of the preliminary order, SWEPCo believes it is probable the PUCT will disallow capitalized AFUDC in excess of the Texas jurisdictional capital cost cap and recorded a pretax, non-cash disallowance of $86 million in the fourth quarter of 2023. Such determination may reduce SWEPCo's future revenues by approximately $15 million on an annual basis. On December 21, 2023, SWEPCo filed a motion with the PUCT for reconsideration of the preliminary order. In January 2024, the PUCT denied the motion for reconsideration of the preliminary order.

The PUCT's December 2023 approval of the preliminary order determined that it will address, in the ongoing PUCT remand proceeding, any potential revenue refunds to customers that may be required by future PUCT orders. In January 2024, the PUCT established a procedural schedule for the remand proceeding. Supplemental testimony from SWEPCo is due in March 2024, intervenor and staff testimony is due in April 2024 and a hearing is scheduled for May 2024. Although SWEPCo does not currently believe any refunds are probable of occurring, SWEPCo estimates it could be required to make customer refunds, including interest, ranging from $0 to $200 million related to revenues collected from February 2013 through December 2023.

2016 Texas Base Rate Case

In 2016, SWEPCo filed a request with the PUCT for a net increase in Texas annual revenues of $69 million based upon a 10% ROE. In January 2018, the PUCT issued a final order approving a net increase in Texas annual revenues of $50 million based upon a ROE of 9.6%, effective May 2017. The final order also included: (a) approval to recover the Texas jurisdictional share of environmental investments placed in-service, as of June 30, 2016, at various plants, including Welsh
Plant, Units 1 and 3, (b) approval of recovery of, but no return on, the Texas jurisdictional share of the net book value of Welsh Plant, Unit 2, (c) approval of $2 million in additional vegetation management expenses and (d) the rejection of SWEPCo's proposed transmission cost recovery mechanism.

As a result of the final order, in 2017 SWEPCo: (a) recorded an impairment charge of $19 million, which included $7 million associated with the lack of return on Welsh Plant, Unit 2 and $12 million related to other disallowed plant investments, (b) recognized $32 million of additional revenues, for the period of May 2017 through December 2017, that was surcharged to customers in 2018 and (c) recognized an additional $7 million of expenses consisting primarily of depreciation expense and vegetation management expense, offset by the deferral of rate case expense. SWEPCo implemented new rates in February 2018 billings. The $32 million of additional 2017 revenues was collected during 2018. In March 2018, the PUCT clarified and corrected portions of the final order, without changing the overall decision or amounts of the rate change. The order has been appealed by various intervenors related to limiting SWEPCo's recovery of AFUDC on Turk Plant and recovery of Welsh Plant, Unit 2. If certain parts of the PUCT order are overturned, it could reduce future net income and cash flows and impact financial condition.

2020 Texas Base Rate Case

In October 2020, SWEPCo filed a request with the PUCT for a $105 million annual increase in Texas base rates based upon a proposed 10.35% ROE. The request would move transmission and distribution interim revenues recovered through riders into base rates. Eliminating these riders would result in a net annual requested base rate increase of $90 million primarily due to increased investments. SWEPCo subsequently filed a request with the PUCT lowering the requested annual increase in Texas base rates to $100 million which would result in an $85 million net annual base rate increase after moving the proposed riders to rate base.

In January 2022, the PUCT issued a final order approving an annual revenue increase of $39 million based upon a 9.25% ROE. The order also includes: (a) rates implemented retroactively back to March 18, 2021, (b) $5 million of the proposed increase related to vegetation management, (c) $2 million annually to establish a storm catastrophe reserve and (d) the creation of a rider to recover the Dolet Hills Power Station as if it were in rate base until its retirement at the end of 2021 and starting in 2022 the remaining net book value to be recovered as a regulatory asset through 2046. As a result of the final order, SWEPCo recorded a disallowance of $12 million in 2021 associated with the lack of return on the Dolet Hills Power Station. In February 2022, SWEPCo filed a motion for rehearing with the PUCT challenging several errors in the order, which include challenges of the approved ROE, the denial of a reasonable return or carrying costs on the Dolet Hills Power Station and the calculation of the Texas jurisdictional share of the storm catastrophe reserve. In April 2022, the PUCT denied the motion for rehearing. In May 2022, SWEPCo filed a petition for review with the Texas District Court seeking a judicial review of the several errors challenged in the PUCT's final order.

2020 Louisiana Base Rate Case

In December 2020, SWEPCo filed a request with the LPSC for a $134 million annual increase in Louisiana base rates based upon a proposed 10.35% ROE. SWEPCo's requested annual increase includes accelerated depreciation related to the Dolet Hills Power Station, Pirkey Power Plant and Welsh Plant, all of which were or are expected to be retired early. SWEPCo also included recovery of Welsh Plant, Unit 2 over the blended useful life of Welsh Plant, Units 1 and 3. SWEPCo subsequently revised the requested annual increase to $95 million to reflect removing hurricane storm restoration costs from the base case filing, to modify the proposed recovery of the Dolet Hills Power Station and revisions to various proposed amortizations. The hurricane costs have been requested in a separate storm filing. See "2021 Louisiana Storm Cost Filing" below for more information.

In January 2023, the LPSC approved a settlement which provides for an annual revenue increase of $27 million based upon a 9.5% ROE and includes: (a) a $21 million increase in base rates effective February 2023, (b) a $14 million rider to recover costs of the Dolet Hills Power Station and Pirkey Power Plant including a return, (c) an $8 million reduction in fuel rates, (d) adoption of a 3-year formula rate term subject to an earnings band and (e) the recovery of certain incremental SPP charges
net of associated revenue and the Louisiana jurisdictional share of the return on and of projected transmission capital investment outside of the earnings band. The settlement agreement did not rule on the prudency of the early retirement of the Dolet Hills Power Station, which is being addressed in a separate proceeding.

The primary differences between SWEPCo's requested annual rate increase and the agreed upon settlement increase are primarily due to: (a) a reduction in the requested ROE, (b) recovery of the Dolet Hills Power Station and Pirkey Plant over ten years in a separate rider mechanism as opposed to base rates with accelerated depreciation rates, (c) maintaining existing depreciation rates for Welsh Plant, Units 1 and 3 and (d) the severing of SWEPCo's proposed adjustment to include a stand-alone NOLC deferred tax asset in rate base.

In January 2023, a hearing was held related to the inclusion of a stand-alone NOLC deferred tax asset in rate base. In September 2023, an order was received from the LPSC directing SWEPCo to seek a private letter ruling from the IRS to address the matter.

2021 Louisiana Storm Cost Filing

In 2020, Hurricanes Laura and Delta caused power outages and extensive damage to the SWEPCo service territories, primarily impacting the Louisiana jurisdiction. Following both hurricanes, the LPSC issued orders allowing Louisiana utilities, including SWEPCo, to establish regulatory assets to track and defer expenses associated with these storms. In February 2021, severe winter weather impacted the Louisiana jurisdiction and in March 2021, the LPSC approved the deferral of incremental storm restoration expenses related to the winter storm. In March 2023, SWEPCo and the LPSC staff filed a joint stipulation and settlement agreement with the LPSC which confirmed the prudency of $150 million of deferred incremental storm restoration expenses. The agreement also authorized an interim carrying charge at a rate of 3.125% until the recovery mechanism is determined in phase two of this proceeding. In April 2023, the LPSC issued an order approving the stipulation and settlement agreement. In July 2023, SWEPCo submitted additional information in phase two of this proceeding to obtain a financing order and prudency review of capital investment. The procedural schedule for this case states that a hearing will take place in the second quarter of 2024.

February 2021 Severe Winter Weather Impacts in SPP

In February 2021, severe winter weather had a significant impact in SPP, resulting in significantly increased market prices for natural gas power plants to meet reliability needs for the SPP electric system. For the time period of February 9, 2021, to February 20, 2021, SWEPCo's natural gas expenses and purchases of electricity still to be recovered from customers are shown in the table below:

Jurisdiction	December 31, 2023	December 31, 2022	Approved Recovery Period	Approved Carrying Charge
	(in millions)			
Arkansas	$ 54.2	$ 74.9	6 years	(a)
Louisiana	97.2	121.7	(b)	(b)
Texas	101.9	132.4	5 years	1.65%
Total	$ 253.3	$ 329.0		

(a) SWEPCo is permitted to record carrying costs on the unrecovered balance of fuel costs at a weighted-cost of capital approved by the APSC. The APSC will conclude an audit of these costs in 2024. A hearing is scheduled for May 2024.
(b) In March 2021, the LPSC approved a special order granting a temporary modification to the FAC and shortly after SWEPCo began recovery of its Louisiana jurisdictional share of these fuel costs based on a five-year recovery period inclusive of an interim carrying charge equal to the prime rate. The special order states the fuel and purchased power costs incurred will be subject to a future LPSC audit.

If SWEPCo is unable to recover any of the costs relating to the extraordinary fuel and purchases of electricity, or obtain authorization of a reasonable carrying charge on these costs, it could reduce future net income and cash flows and impact financial condition.

FERC 2019 SPP Transmission Formula Rate Challenge

In May 2021, certain joint customers submitted a formal challenge at the FERC related to the 2020 Annual Update of the 2019 SPP Transmission Formula Rates of the AEP transmission owning subsidiaries within SPP. In March 2022, the FERC issued an order granting the formal challenge on several issues and denying the formal challenge on other issues. Management has determined that the result of the order had an immaterial impact to the financial statements of AEP, AEPTCo, PSO and SWEPCo. In November 2022, certain joint customers appealed the FERC denial of issues to the U.S. Court of Appeals for the District of Columbia Circuit. In January 2024, the court agreed with the FERC’s order and denied the certain joint customers petition for review.

FERC 2021 PJM and SPP Transmission Formula Rate Challenge

SWEPCo 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, SWEPCo’s 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 Accumulated Provision for Rate Refunds 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 Other Regulatory Liabilities or a reduction to Other 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. SWEPCo has not yet been directed to make cash refunds related to the 2022 or 2023 rate years.

The impact of the FERC's order on the pretax net income of SWEPCo was not material.

Request to Update SWEPCo Generation Depreciation Rates

In October 2023, SWEPCo filed an application to revise its generation wholesale customer’s contracts to reflect an increase in the annual revenue requirement of approximately $5 million for updated depreciation rates and allow for the return on and of FERC customers jurisdictional share of regulatory assets associated with retired plants. In November 2023, certain intervenors filed a motion with the FERC protesting and recommending the rejection of SWEPCo’s filings. In December 2023, the FERC issued an order approving the proposed rates effective January 1, 2024, subject to further review and refund and established hearing and settlement proceedings. If SWEPCo is unable to recover the remaining regulatory assets associated with retired plants, it could reduce future net income and cash flows and impact financial condition.

5. <u>EFFECTS OF REGULATION</u>

Coal-Fired Generation Plants

Compliance with extensive environmental regulations requires significant capital investment in environmental monitoring, installation of pollution control equipment, emission fees, disposal costs and permits. Management continuously evaluates cost estimates of complying with these regulations which has resulted in, and in the future may result in, a decision to retire coal-fired generating facilities earlier than their currently estimated useful lives.

Management is seeking or will seek regulatory recovery, as necessary, for any net book value remaining when the plants are retired. To the extent the net book value of these generation assets is not deemed recoverable, it could materially reduce future net income and cash flows and impact financial condition.

Regulated Generating Units that have been Retired

In December 2021, the Dolet Hills Power Station was retired. As part of the 2020 Texas Base Rate Case, the PUCT authorized recovery of SWEPCo’s Texas jurisdictional share of the Dolet Hills Power Station through 2046, but denied SWEPCo the ability to earn a return on this investment resulting in a disallowance of $12 million in 2021. As part of the 2021 Arkansas Base Rate Case, the APSC authorized recovery of SWEPCo’s Arkansas jurisdictional share of the Dolet Hills Power Station through 2027, but denied SWEPCo the ability to earn a return on this investment resulting in a disallowance of $2 million in the second quarter of 2022. Also, the APSC did not rule on the prudency of the early retirement of the Dolet Hills Power Station, which will be addressed in a future proceeding. As part of the 2020 Louisiana Base Rate Case, the LPSC authorized the recovery of SWEPCo’s Louisiana share of the Dolet Hills Power Station, through a separate rider, through 2032, but did not rule on the prudency of the early retirement of the plant, which is being addressed in a separate proceeding. See “2020 Texas Base Rate Case” and “2020 Louisiana Base Rate Case” sections of Note 4 for additional information.

In March 2023, the Pirkey Plant was retired. As part of the 2020 Louisiana Base Rate Case, the LPSC authorized the recovery of SWEPCo’s Louisiana jurisdictional share of the Pirkey Plant, through a separate rider, through 2032. As part of the 2021 Arkansas Base Rate Case, the APSC granted SWEPCo regulatory asset treatment. SWEPCo will request recovery including a weighted average cost of capital carrying charge through a future proceeding. In July 2023, Texas ALJs issued a proposal for decision that concluded the decision to retire the Pirkey Plant was prudent. In September 2023, the PUCT rejected the ALJs proposal for decision concluding the retirement of the Pirkey Plant was prudent. In the open meeting, the commissioners expressed their concerns that the analysis in support of SWEPCo’s decision to retire the Pirkey Plant was not robust enough and that SWEPCo should have re-evaluated the decision following Winter Storm Uri. The treatment of the cost of recovery of the Pirkey Plant is expected to be addressed in a future rate case. As of December 31, 2023, the Texas jurisdictional share of the net book value of the Pirkey Plant was $67 million. To the extent any portion of the Texas jurisdictional share of the net book value of the Pirkey Plant is not recoverable, it could reduce future net income and cash flows and impact financial condition.

Regulated Generating Unit to be Retired

In November 2020, management announced that it will cease using coal at the Welsh Plant in 2028. As a result of the announcement, SWEPCo began recording accelerated depreciation.

The table below summarizes the net book value including CWIP, before cost of removal and materials and supplies, as of December 31, 2023, of generating facilities planned for early retirement:

Plant	Net Book Value	Accelerated Depreciation	Cost of Removal	Projected Retirement Date	Current Authorized Recovery Period	Annual Depreciation (a)
			(dollars in millions)			
Welsh Plant, Units 1 and 3	$ 352.0	$ 125.6	$ 58.2 (b)	2028 (c)	(d)	$ 38.6

(a) Represents the amount of annual depreciation that has been collected from customers over the prior 12-month period.
(b) Includes Welsh Plant, Unit 2, which was retired in 2016. Removal of Welsh Plant, Unit 2, will be performed with the removal of Welsh Plant, Units 1 and 3, after retirement.
(c) Represents projected retirement date of coal assets, units are being evaluated for conversion to natural gas after 2028.
(d) Unit 1 is being recovered through 2027 in the Louisiana jurisdiction and through 2037 in the Arkansas and Texas jurisdictions. Unit 3 is being recovered through 2032 in the Louisiana jurisdiction and through 2042 in the Arkansas and Texas jurisdictions.

Dolet Hills Power Station and Related Fuel Operations

In December 2021, the Dolet Hills Power Station was retired. While in operation, DHLC provided 100% of the fuel supply to Dolet Hills Power Station. The remaining book value of Dolet Hills Power Station non-fuel related assets are recoverable by SWEPCo through rate riders. As of December 31, 2023, SWEPCo’s share of the net investment in the Dolet Hills Power Station was $103 million, including materials and supplies, net of cost of removal collected in rates. Fuel costs incurred by the Dolet Hills Power Station are recoverable by SWEPCo through active fuel clauses and are subject to prudency determinations by the various commissions. After closure of the DHLC mining operations and the Dolet Hills Power Station, additional reclamation and other land-related costs incurred by DHLC and Oxbow will continue to be billed to SWEPCo and included in existing fuel clauses. As of December 31, 2023, SWEPCo had a net under-recovered fuel balance of $77 million, inclusive of costs related to the Dolet Hills Power Station billed by DHLC, but excluding impacts of the February 2021 severe winter weather event.

In March 2021, the LPSC issued an order allowing SWEPCo to recover up to $20 million of fuel costs in 2021 and defer approximately $35 million of additional costs with a recovery period to be determined at a later date. In August 2022, the LPSC staff filed testimony recommending fuel disallowances of up to $55 million, including denial of recovery of the $35 million deferral, with refunds to customers over five years. In February 2024, an ALJ issued a final recommendation which included a proposed $55 million refund to customers and the denial of recovery of the $35 million deferral. SWEPCo filed a motion to present oral arguments with the LPSC to dispute the ALJ’s recommendations. Management believes its financial statements adequately address the impact of the LPSC staff and ALJ recommendations. A decision from the LPSC is expected in the first quarter of 2024.

In March 2021, the APSC approved fuel rates that provide recovery of $20 million for the Arkansas share of the 2021 Dolet Hills Power Station fuel costs over five years through the existing fuel clause.

In September 2023, the PUCT approved an unopposed settlement agreement that provides recovery of $48 million of Oxbow mine related costs through 2035.

If any of these costs are not recoverable or customer refunds are required, it could reduce future net income and cash flows and impact financial condition.

Pirkey Plant and Related Fuel Operations

In March 2023, the Pirkey Plant was retired. SWEPCo is recovering, or will seek recovery of, the remaining net book value of Pirkey Plant non-fuel costs. As of December 31, 2023, SWEPCo's share of the net investment in the Pirkey Plant was $182 million, including materials and supplies, net of cost of removal. See the "Regulated Generating Units that have been Retired" section above for additional information. Fuel costs are recovered through active fuel clauses and are subject to prudency determinations by the various commissions. As of March 31, 2023, SWEPCo fuel deliveries, including billings of all fixed costs, from Sabine ceased. Additionally, as of December 31, 2023, SWEPCo had a net under-recovered fuel balance of $77 million, inclusive of costs related to the Pirkey Plant billed by Sabine, but excluding impacts of the February 2021 severe winter weather event. Remaining operational, reclamation and other land-related costs incurred by Sabine will be billed to SWEPCo and included in existing fuel clauses.

In July 2023, the LPSC ordered that a separate proceeding be established to review the prudence of the decision to retire the Pirkey Plant, including the costs included in fuel for years starting in 2019 and after. In September 2023, the PUCT approved an unopposed settlement agreement that provides recovery of $33 million of Sabine related fuel costs through 2035.

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

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2023	December 31, 2022	Remaining Recovery Period
Regulatory Assets:	(in millions)		
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Unrecovered Winter Storm Fuel Costs (a)	$ 60.1	$ 84.6	
Pirkey Plant Accelerated Depreciation - Arkansas	35.2	—	
NOLC Carrying Charges	15.5	—	
Other Regulatory Assets Pending Final Regulatory Approval	26.0	34.5	
Total Regulatory Assets Currently Earning a Return	136.8	119.1	
Regulatory Assets Currently Not Earning a Return			
Storm-Related Costs - Louisiana, Texas	56.0	151.5	
Asset Retirement Obligation - Louisiana	—	11.8	
Other Regulatory Assets Pending Final Regulatory Approval	13.7	16.0	
Total Regulatory Assets Currently Not Earning a Return	69.7	179.3	
Total Regulatory Assets Pending Final Regulatory Approval	206.5	298.4	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Unrecovered Winter Storm Fuel Costs (a)	193.2	244.4	4 years
Storm-Related Costs - Louisiana	144.7	—	2 years
Under-recovered Fuel Costs (b)	76.9	257.2	1 year
Fuel Mine Closure Costs - Texas	74.3	—	12 years
Pirkey Plant Accelerated Depreciation - Louisiana	65.8	—	9 years
Plant Retirement Costs - Unrecovered Plant, Dolet Hills Power Station - Louisiana	40.8	—	9 years
Environmental Controls Projects	8.9	10.0	9 years
Other Regulatory Assets Approved for Recovery	5.0	6.9	various
Total Regulatory Assets Currently Earning a Return	609.6	518.5	
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets	285.9	267.1	(c)
Pension and OPEB Funded Status	99.9	88.7	12 years
Plant Retirement Costs - Unrecovered Plant, Texas	48.7	51.7	23 years
North Central Wind Rider	20.2	6.4	2 years
Plant Retirement Costs - Unrecovered Plant, Arkansas	17.3	21.1	4 years
Unrealized Loss on Forward Commitments	15.4	—	2 years
Other Regulatory Assets Approved for Recovery	26.1	30.2	various
Total Regulatory Assets Currently Not Earning a Return	513.5	465.2	
Total Regulatory Assets Approved for Recovery	1,123.1	983.7	
Total FERC Account 182.3 Regulatory Assets	$ 1,329.6	$ 1,282.1	

(a) See "February 2021 Severe Winter Weather Impacts in SPP" section of SWEPCo Rate Matters in Note 4 for additional information.
(b) Amounts include Arkansas and Texas jurisdictions.
(c) Recovered over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets.

	December 31, 2023	December 31, 2022	Remaining Refund Period
Regulatory Liabilities:	(in millions)		
Regulatory liabilities pending final regulatory determination:			
Regulatory Liabilities Currently Paying a Return			
NOLC Carrying Charges	$ 15.5	$ —	
Income Tax Liabilities (a)	7.0	7.0	
Total Regulatory Liabilities Pending Final Regulatory Determination	22.5	7.0	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Income Tax Liabilities (a)	578.3	594.8	(b)
Other Regulatory Liabilities Approved for Payment	7.7	3.7	various
Total Regulatory Liabilities Currently Paying a Return	586.0	598.5	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Approved for Payment	8.9	7.2	various
Total Regulatory Liabilities Currently Not Paying a Return	8.9	7.2	
Total Regulatory Liabilities Approved for Payment	594.9	605.7	
Total FERC 254 Account Regulatory Liabilities	$ 617.4	$ 612.7	

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

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

SWEPCo 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 SWEPCo'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)	$ 109.2	$ 48.1	$ —	$ —	$ 157.3
Energy and Capacity Purchase Contracts	16.4	26.2	2.2	—	44.8
Total	$ 125.6	$ 74.3	$ 2.2	$ —	$ 202.1

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

GUARANTEES

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

Indemnifications and Other Guarantees

Contracts

SWEPCo 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 PSO and SWEPCo, who are jointly and severally liable for activity conducted on their behalf.

Lease Obligations

SWEPCo leases equipment under master lease agreements. See "Master Lease Agreements" section of Note 13 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. SWEPCo 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, SWEPCo was named as a Potentially Responsible Party (PRP) for one site by the Federal EPA for which alleged liability is unresolved. There are three additional sites for which SWEPCo 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

SWEPCo maintains insurance coverage normal and customary for electric utilities, subject to various deductibles. SWEPCo 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 SWEPCo. 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. ACQUISITIONS AND IMPAIRMENTS

ACQUISITIONS

North Central Wind Energy Facilities

In 2020, PSO and SWEPCo received regulatory approvals to acquire the NCWF, comprised of three Oklahoma wind facilities totaling 1,484 MWs, on a fixed cost turn-key basis. PSO and SWEPCo own undivided interests of 45.5% and 54.5% of the NCWF, respectively. In total, the three wind facilities cost approximately $2 billion and consist of Traverse (998 MW), Maverick (287 MW) and Sundance (199 MW). Output from the NCWF serves retail load in PSO's Oklahoma service territory and both retail and FERC wholesale load in SWEPCo's service territories in Arkansas and Louisiana. The Louisiana portion of the NCWF revenue requirement, net of PTC benefit, is recoverable through authorized riders until the amounts are reflected in base rates. Recovery of the Arkansas portion of the NCWF revenue requirement through base rates was approved by the APSC in May 2022. The NCWF are subject to various regulatory performance requirements. If these performance requirements are not met, SWEPCo would recognize a regulatory liability to refund retail customers.

In April 2021, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Sundance during its development and construction for $270 million. Sundance was placed in-service in April 2021. In September 2021, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Maverick during its development and construction for $383 million. Maverick was placed in-service in September 2021. In March 2022, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Traverse during its development and construction for $1.2 billion. Traverse was placed in-service in March 2022. Immediately following the acquisitions, PSO and SWEPCo liquidated the entities and simultaneously distributed the assets in proportion to their undivided ownership interests. SWEPCo applies the joint plant accounting model to account for its respective undivided interests in the assets, liabilities, revenues and expenses of the NCWF projects.

IMPAIRMENTS

2012 Texas Base Rate Case

In December 2023, SWEPCo recorded a pretax, non-cash disallowance of $86 million in Other Deductions on the statements of income due to regulatory disallowance of recovery of AFUDC on Turk Plant in the 2012 Texas Base Rate case. See the "2012 Texas Base Rate Case" section of Note 4 for additional information.

2020 Texas Base Rate Case

In January 2022, the PUCT issued a final order which included a return of investment only for the recovery of the Dolet Hills Power Station. As a result of the final order, SWEPCo recorded a disallowance of $12 million associated with the lack of return on the Dolet Hills Power Station. In February 2022, SWEPCo filed a motion for rehearing with the PUCT challenging denial of a reasonable return or carrying costs on the Dolet Hills Power Station among other items. In April 2022, the PUCT denied the motion for rehearing. In May 2022, SWEPCo filed a petition for review with the Texas District Court seeking a judicial review of the several errors challenged in the PUCT's final order. See "2020 Texas Base Rate Case" section of Note 4 for additional information.

8. 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.

SWEPCo participates in an AEP sponsored qualified pension plan and two unfunded non-qualified pension plans. Substantially all employees are covered by the qualified plan or both the qualified and a non-qualified pension plan. SWEPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

SWEPCo recognizes the funded status associated with defined benefit pension and OPEB plans on the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. SWEPCo recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, 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. SWEPCo records a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for rate-making purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		OPEB	
	December 31,			
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	5.00 % (a)	5.00 % (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	5.00 %	5.00 %	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,	$ 250.7	$ 317.7	$ 55.1	$ 65.2
Service Cost	7.7	10.6	0.4	0.6
Interest Cost	13.9	9.1	2.9	1.8
Actuarial Loss	16.8	(57.9)	1.2	(6.6)
Benefit Payments	(27.9)	(28.8)	(8.8)	(8.8)
Participant Contributions	—	—	2.9	2.9
Medicare Subsidy	—	—	—	—
Benefit Obligation as of December 31,	$ 261.2	$ 250.7	$ 53.7	$ 55.1
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 231.3	$ 308.3	$ 103.0	$ 136.6
Actual Gain (Loss) on Plan Assets	23.9	(48.3)	14.0	(27.7)
Company Contributions	0.2	0.1	—	—
Participant Contributions	—	—	2.9	2.9
Benefit Payments	(27.9)	(28.8)	(8.8)	(8.8)
Fair Value of Plan Assets as of December 31,	$ 227.5	$ 231.3	$ 111.1	$ 103.0
Funded Status as of December 31,	$ (33.7)	$ (19.4)	$ 57.4	$ 47.9

	Pension Plans		OPEB	
	2023	**2022**	**2023**	**2022**
	(in millions)			
Special Funds – Prepaid Benefit Costs	$ —	$ —	$ 57.4	$ 47.9
Miscellaneous Current and Accrued Liabilities – Short-term Benefit Liability	(0.1)	(0.1)	—	—
Accumulated Provision for Pensions and Benefits – Long-term Benefit Liability	(33.6)	(19.3)	—	—
Funded (Underfunded) Status	$ (33.7)	$ (19.4)	$ 57.4	$ 47.9

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

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

	Pension Plans		OPEB	
	2023	**2022**	**2023**	**2022**
Components	(in millions)			
Net Actuarial Loss	$ 89.6	$ 77.6	$ 18.4	$ 25.0
Prior Service Credit	—	—	(2.1)	(7.0)
Recorded as				
Regulatory Assets	$ 89.7	$ 77.6	$ 10.2	$ 11.2
Deferred Income Taxes	—	—	1.3	1.5
Net of Tax AOCI	(0.1)	—	4.8	5.3

	Pension Plans		OPEB	
	2023	**2022**	**2023**	**2022**
Components	(in millions)			
Actuarial Gain (Loss) During the Year	$ 12.1	$ 5.0	$ (5.6)	$ 28.5
Amortization of Actuarial Loss	(0.1)	(3.8)	(1.0)	—
Amortization of Prior Service Credit	—	—	4.9	5.3
Change for the Year Ended December 31,	$ 12.0	$ 1.2	$ (1.7)	$ 33.8

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 SWEPCo using the percentages in the table below:

Pension Plan		OPEB	
December 31,			
2023	2022	2023	2022
5.5 %	5.6 %	6.6 %	6.6 %

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	December 31, 2022
	(in millions)	
Qualified Pension Plan	$ 241.9	$ 234.0
Nonqualified Pension Plans	1.0	1.1
Total	$ 242.9	$ 235.1

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	December 31, 2022
	(in millions)	
Projected Benefit Obligation	$ 261.2	$ 250.7
Fair Value of Plan Assets	227.5	231.3
Underfunded Projected Benefit Obligation	$ (33.7)	$ (19.4)

Accumulated Benefit Obligation

	December 31, 2023	December 31, 2022
	(in millions)	
Accumulated Benefit Obligation	$ 242.9	$ 235.1
Fair Value of Plan Assets	227.5	231.3
Underfunded Accumulated Benefit Obligation	$ (15.4)	$ (3.8)

Estimated Future Benefit Payments and Contributions

SWEPCo expects contributions and payments for the pension plans of $101 thousand during 2024. For the pension plans, this amount includes the payment of unfunded nonqualified benefits plus contributions to the qualified trust fund of at least the minimum amount required by the Employee Retirement Income Security Act. For the qualified pension plan, SWEPCo may also make additional discretionary contributions to maintain the funded status of the plan.

The table below reflects the total benefits expected to be paid from the plan or from SWEPCo'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:

	Estimated Payments	
Pension Plans	**Pension Plans**	**OPEB**
	(in millions)	
2024	$ 24.4	$ 7.8
2025	25.8	8.3
2026	26.1	8.3
2027	25.3	8.1
2028	23.7	8.2
Years 2029 to 2033, in Total	105.6	38.8

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	$ 7.7	$ 10.6	$ 0.4	$ 0.6
Interest Cost	13.9	9.1	2.9	1.8
Expected Return on Plan Assets	(19.4)	(14.6)	(7.2)	(7.3)
Amortization of Prior Service Credit	—	—	(4.9)	(5.3)
Amortization of Net Actuarial Loss	0.1	3.8	1.0	—
Net Periodic Benefit Cost (Credit)	2.3	8.9	(7.8)	(10.2)
Capitalized Portion	(3.0)	(4.0)	(0.2)	(0.2)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ (0.7)	$ 4.9	$ (8.0)	$ (10.4)

American Electric Power System Retirement Savings Plan

SWEPCo 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 plans for the years ended December 31, 2023 and 2022 were $7 million and $6 million, respectively.

9. BUSINESS SEGMENTS

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

10. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of SWEPCo.

SWEPCo 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 SWEPCo 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, SWEPCo 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.

SWEPCo 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. SWEPCo 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. SWEPCo 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, Energy Supply 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 the Registrants' outstanding derivative contracts:

Notional Volume of Derivative Instruments

Primary Risk Exposure	2023	2022	Unit of Measure
	(in millions)		
Commodity:			
Power	2.9	2.2	MWhs
Natural Gas	17.9	2.1	MMBtus
Heating Oil and Gasoline	0.9	1.0	Gallons

Cash Flow Hedging Strategies

SWEPCo 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. SWEPCo does not hedge all commodity price risk.

SWEPCo utilizes a variety of interest rate derivative transactions in order to manage interest rate risk exposure. SWEPCo also utilizes interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. SWEPCo 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, SWEPCo 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," SWEPCo 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, SWEPCo 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 SWEPCo 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 SWEPCo as of December 31, 2023 and 2022.
The following tables represent the gross fair value of SWEPCo'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	$ 12.5	$ (0.9)	$ 11.6
Long-Term Portion of Derivative Instrument Assets	0.5	(0.5)	—
Derivative Instrument Liabilities	16.6	(1.0)	15.6
Long-Term Portion of Derivative Instrument Liabilities	1.7	(0.5)	1.2

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	$ 16.8	$ (0.4)	$ 16.4
Long-Term Portion of Derivative Instrument Assets	—	—	—
Derivative Instrument Liabilities	2.0	(0.6)	1.4
Long-Term Portion of Derivative Instrument Liabilities	—	—	—

(a) Derivative instruments within these categories 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)	
Operation Expenses	$ —	$ 0.8
Maintenance Expenses	(0.2)	1.1
Other Regulatory Assets (a)	(15.5)	(2.1)
Other Regulatory Liabilities (a)	70.7	77.9
Total Gain on Risk Management Contracts	$ 55.0	$ 77.7

(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), SWEPCo 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, SWEPCo did not apply cash flow hedging to outstanding power derivatives.

SWEPCo 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 year ended 2023, SWEPCo applied cash flow hedging to outstanding interest rate derivatives. During the year ended 2022, SWEPCo did not apply cash flow hedging to outstanding interest rate derivatives.
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 AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	December 31, 2022 AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
Interest Rate			
	(in millions)		
$ 1.3	$ 0.3	$ 1.1	$ 0.2

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. SWEPCo has not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. SWEPCo 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 SWEPCo 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. SWEPCo'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 SWEPCo'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. SWEPCo had derivative contracts with cross-default provisions in a net liability position of $15 million and no cash collateral posted as of December 31, 2023. SWEPCo's derivative contracts with cross-default provisions outstanding as of December 31, 2022 were not material.

11. 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)			
$ 3,668.9	$ 3,209.7	$ 3,319.1	$ 2,778.1

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, SWEPCo'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)				
Derivative Instrument Assets					
Risk Management Commodity Contracts (a)	$ —	$ 0.5	$ 12.0	$ (0.9)	$ 11.6
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a)	$ —	$ 15.7	$ 0.9	$ (1.0)	$ 15.6

	December 31, 2022				
	Level 1	Level 2	Level 3	Other	Total
Assets:	(in millions)				
Derivative Instrument Assets					
Risk Management Commodity Contracts (a)	$ —	$ 2.2	$ 14.6	$ (0.4)	$ 16.4
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a)	$ —	$ 1.6	$ 0.4	$ (0.6)	$ 1.4

(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	$ 14.2
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	20.0
Settlements	(34.2)
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	11.1
Balance as of December 31, 2023	$ 11.1

Year Ended December 31, 2022	Derivative Instrument Assets (Liabilities)
	(in millions)
Balance as of December 31, 2021	$ 10.9
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	35.8
Settlements	(45.0)
Transfers out Level 3 (c)	6.9
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	5.6
Balance as of December 31, 2022	$ 14.2

(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) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(d) 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

Type of Input	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High	Weighted Average (c)
	(in millions)						
Natural Gas Contracts	$ —	$ 0.5	Discounted Cash Flow	Forward Market Price (b)	$ 3.11	$ 3.11	$ 3.11
FTRs	12.0	0.4	Discounted Cash Flow	Forward Market Price (a)	(25.45)	4.80	(4.33)
Total	$ 12.0	$ 0.9					

December 31, 2022

Type of Input	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Input/Range Low	Input/Range High	Weighted Average (c)
	(in millions)						
FTRs	$ 14.6	$ 0.4	Discounted Cash Flow	Forward Market Price	$ (36.45)	$ 3.40	$ (7.55)

(a) Represents market prices in dollars per MWh.
(b) Represents market prices in dollars per MMBtu.

(c) 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 Natural Gas Contracts and FTRs as of December 31, 2023 and 2022:

Uncertainty of Fair Value Measurements

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

12. INCOME TAXES

Income Tax Benefit

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

	Years Ended December 31,	
	2023	2022
	(in millions)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ (72.6)	$ (39.6)
Deferred	56.5	17.4
Total	(16.1)	(22.2)
Charged (Credited) to Non-Operating Income, Net:		
Current	(18.8)	(4.6)
Deferred	0.6	0.5
Total	(18.2)	(4.1)
Income Tax Benefit	$ (34.3)	$ (26.3)

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

	Years Ended December 31,	
	2023	2022
	(in millions)	
Net Income	$ 220.3	$ 290.1
Less: Equity Earnings – Dolet Hills	(1.5)	(1.4)
Income Tax Benefit	(34.3)	(26.3)
Pretax Income	$ 184.5	$ 262.4
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 38.7	$ 55.1
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Reversal of Origination Flow-Through	2.1	2.3
Depletion	—	(4.0)
State and Local Income Taxes, Net	(4.0)	(4.9)
AFUDC	(2.4)	—
Return to Provision Adjustment	1.0	—
Disallowance Cost	12.0	—
Tax Reform Excess ADIT Reversal	(12.6)	(14.8)
Production Tax Credits	(67.1)	(57.1)
Other	(2.0)	(2.9)
Income Tax Benefit	$ (34.3)	$ (26.3)
Effective Income Tax Rate	(18.6)%	(10.0)%

Net Deferred Tax Asset

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

	December 31,	
	2023	2022
	(in millions)	
Deferred Tax Assets	$ 412.9	$ 358.2
Deferred Tax Liabilities	(1,594.6)	(1,447.0)
Net Deferred Tax Assets	$ (1,181.7)	$ (1,088.8)
Property Related Temporary Differences	$ (1,087.2)	$ (1,053.8)
Amounts Due to Customers for Future Income Taxes	142.5	146.2
Deferred State Income Taxes	(238.6)	(208.7)
Regulatory Assets	(143.3)	(114.1)
Tax Credit Carryforward	68.6	66.0
Net Operating Loss Carryforward	47.5	42.7
All Other, Net	28.8	32.9
Net Deferred Tax Assets	$ (1,181.7)	$ (1,088.8)

Tax Credit Carryforward

As of December 31, 2023, SWEPCo has federal tax credit carryforwards in the amount of $69 million. If these credits are not utilized, federal general business tax credits will expire in the years 2036 through 2041. SWEPCo anticipates future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

Valuation Allowance

SWEPCo assesses the available positive and negative evidence to estimate whether sufficient future taxable income of the appropriate tax character will be generated to realize the benefits of existing deferred tax assets. When the evaluation of the evidence indicates that it is more-likely-than-not that SWEPCo will not be able to realize the benefits of existing deferred tax assets, a valuation allowance is recorded to reduce existing deferred tax assets to the net realizable amount. Objective evidence evaluated includes whether SWEPCo has a history of recognizing income, future reversals of existing temporary differences and tax planning strategies.

Federal and State Income Tax Audit Status

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

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

Net Income Tax Operating Loss Carryforward

SWEPCo has state net income tax operating loss carryforwards as of December 31, 2023 as indicated in the table below:

State/Municipality	State Net Income Tax Operating Loss Carryforward		Years of Expiration
	(in millions)		
Arkansas	$	258.9	2024 - 2033
Louisiana		619.1	N/A (a)

(a) NOL's generated beginning in 2001 can be carried forward indefinitely, effective January 1, 2022.

Federal Tax Legislation

In August 2022, President Biden signed H.R. 5376 into law, commonly known as the Inflation Reduction Act of 2022 or IRA. Most notably this budget reconciliation legislation creates a 15% minimum tax on adjusted financial statement income (Corporate Alternative Minimum Tax or CAMT), extends and increases the value of PTCs and ITCs, adds a nuclear and clean hydrogen PTC, an energy storage ITC and allows the sale or transfer of tax credits to third parties for cash. As further significant guidance from Treasury and the IRS is expected on the tax provisions in the IRA, SWEPCo 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 SWEPCo 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 SWEPCo and other AEP subsidiaries 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. SWEPCo and other AEP subsidiaries will continue to monitor and assess any additional guidance.

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

In June 2023, the IRS issued temporary regulations related to the transfer of tax credits. In the third and fourth quarter of 2023, SWEPCo and other AEP subsidiaries, on behalf of PSO, SWEPCo and Energy Supply, entered into transferability agreements with nonaffiliated parties to sell 2023 generated PTCs resulting in cash proceeds of approximately $102 million received in the fourth quarter of 2023 and an additional $76 million expected in early 2024. SWEPCo and other AEP subsidiaries expect to continue to explore the ability to efficiently monetize its tax credits through third party transferability agreements.

13. LEASES

SWEPCo 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. SWEPCo 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 SWEPCo 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, SWEPCo measures its lease obligation using its estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk-free rate and a secured credit spread relative to the lessee on a matched maturity basis.

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

	Years Ended December 31,			
	2023		2022	
	(in millions)			
Operating Lease Cost	$	17.2	$	15.0
Finance Lease Cost:				
Amortization of Right-of-Use Assets		6.5		5.7
Interest on Lease Liabilities		1.4		1.3
Total Lease Rental Costs (a)	$	25.1	$	22.0

(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	22.60	23.59
Finance Leases	4.78	4.89
Weighted-Average Discount Rate:		
Operating Leases	3.52 %	3.42 %
Finance Leases	5.22 %	4.63 %

	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	$	16.2	$	13.4
Operating Cash Flows from Finance Leases		7.1		7.0
Non-cash Acquisitions Under Operating Leases	$	14.3	$	53.6

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

	December 31,			
	2023		2022	
	(in millions)			
Property, Plant and Equipment Under Finance Leases:				
Utility Plant (a)	$	29.0	$	28.2
Obligations Under Finance Leases:				
Noncurrent		18.7		23.2
Current		11.3		5.3
Total Obligations Under Finance Leases	$	30.0	$	28.5

(a) Includes $28 million and $24 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)	$	125.6	$	122.8
Obligations Under Operating Leases:				
Noncurrent		122.2		120.2
Current		8.7		8.4
Total Obligations Under Operating Leases	$	130.9	$	128.6

(a) Includes $32 million and $29 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	$ 12.6	$ 15.8
2025	4.5	14.7
2026	3.9	12.9
2027	3.5	11.5
2028	3.0	9.5
After 2028	7.2	135.6
Total Future Minimum Lease Payments	34.7	200.0
Less: Imputed Interest	4.7	69.1
Estimated Present Value of Future Minimum Lease Payments	$ 30.0	$ 130.9

Master Lease Agreements

SWEPCo 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, SWEPCo 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 SWEPCo for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was $5 million.

Lessor Activity

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

14. 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	2022	Outstanding as of December 31, 2023	2022
Senior Unsecured Notes	2026-2051	3.73%	1.65%-6.20%	1.65%-6.20%	$ 3,675.0	$ 3,325.0
Unamortized Discount, Net					(6.1)	(5.9)
Total Long-term Debt Outstanding					$ 3,668.9	$ 3,319.1

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

	(in millions)
2024	$ —
2025	—
2026	900.0
2027	—
2028	575.0
After 2028	2,200.0
Principal Amount	3,675.0
Unamortized Discount, Net	(6.1)
Total Long-term Debt	$ 3,668.9

Dividend Restrictions

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

All of the dividends declared by SWEPCo 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.

SWEPCo 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 SWEPCo is through the credit agreements. As of December 31, 2023, the maximum amount of restricted net assets of SWEPCo that may not be distributed to the Parent in the form of a loan, advance or dividend was $1.8 billion.

The credit agreement covenant restrictions can limit the ability of SWEPCo to pay dividends out of retained earnings. As of December 31, 2023, the amount of any such restrictions was $337 million.

Corporate Borrowing Program

SWEPCo 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 SWEPCo's balance sheet. SWEPCo'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	$ 401.6	$ 25.8	$ 150.7	$ 16.5	$ 88.7	$ 750.0
2022	358.4	156.6	219.6	109.7	310.7	400.0

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	5.79 %	4.66 %	5.81 %	5.58 %	5.34 %	5.72 %
2022	5.28 %	0.69 %	0.94 %	0.10 %	2.80 %	0.55 %

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 $8 million and $5 million for the years ended December 31, 2023 and 2022, respectively. The interest income related to the corporate borrowing programs was immaterial for the years ended December 31, 2023 and 2022.

Securitized Accounts Receivables – AEP Credit

Under this sale of receivables arrangement, SWEPCo 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 SWEPCo's receivables. The costs of customer accounts receivable sold are reported in Other Deductions on SWEPCo's statements of income. SWEPCo manages and services its customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for SWEPCo 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 $168 million and $194 million, respectively.

The fees paid to AEP Credit for customer accounts receivable sold were $19 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 $1.9 billion and $1.9 billion for the years ended December 31, 2023 and 2022, respectively.

15. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Income Taxes and Investment and Production Tax Credits" section of Note 1 in addition to "Corporate Borrowing Program" and "Securitized Accounts Receivables – AEP Credit" sections of Note 14.

Intercompany Billings

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

Operating Agreement

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.

Sales and Purchases of Property

SWEPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions and the net book value of all sales and purchases for the years ended December 31, 2023 and 2022 were not material. These sales and purchases are recorded in 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, SWEPCo made a $9 million charitable contribution to the AEP Foundation recorded in Donations on the statements of income.

AEP Wind Holdings LLC PPA

Prior to acquisition, Flat Ridge 2 had a PPA with SWEPCo for a portion of their energy production. The SWEPCo portion totaled $14 million for the year ended December 31, 2022 of purchased electricity. AEP disposed of its 50% interest in Flat Ridge 2 in November 2022.

Transmission Service Charges

PSO, SWEPCo and AEPSC are parties to the TCA in connection with the operation of the transmission assets of PSO and SWEPCo. Under the TCA, AEPSC is responsible for monitoring the reliability of their transmission systems and administering the OATT. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to PSO and SWEPCo through the SPP OATT.
SWEPCo recorded the net transmission service charges discussed above of $49 million and $62 million, for the years ended December 31, 2023 and 2022, respectively, in Operation Expenses 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 West Affiliates	$ —	$ 1.3
Transmission Revenues	45.3	51.5
Other Revenues	1.5	1.1
Total Affiliated Revenues	$ 46.8	$ 53.9

16. PROPERTY, PLANT AND EQUIPMENT

Depreciation

SWEPCo 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	Steam	Other Generation	Transmission	Distribution	General
			(in percentages)		
2023	3.2 %	2.1 %	2.2 %	2.9 %	8.5 %
2022	2.8 %	2.4 %	2.3 %	2.9 %	9.0 %

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

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

- In March 2022, PSO and SWEPCo acquired respective undivided ownership interests in the entity that owned Traverse during its development and construction. Immediately following the acquisition, PSO and SWEPCo liquidated the entity and simultaneously distributed the Traverse assets in proportion to their undivided ownership interests. Traverse was placed in-service in March 2022. As a result SWEPCo incurred additional ARO liabilities of $15 million. See the "North Central Wind Energy Facilities" section of Note 7 for additional information.
- In March 2022, SWEPCo recorded a $13 million revision due to an increase in estimated ash pond closure costs at the Pirkey Plant and the Welsh Plant. In September 2022, SWEPCo recorded a $14 million revision due to an increase in estimated landfill closure costs at Pirkey Plant.
- In December 2023, SWEPCo settled $18 million of costs related to closure/reclamation work performed due to the recent retirements of the Pirkey Plant and Dolet Hills Power Station. See "Coal-Fired Generation Plants" section of Note 5 for additional information.

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	$ 159.0	$ 7.8	$ 1.5	$ (23.2)	$ 2.9	$ 148.0 (b)(c)(d)(e)
2022	128.3	6.8	15.4	(25.8)	34.3	159.0 (b)(c)(d)(e)

(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 DHLC.
(d) Includes ARO related to asbestos removal.
(e) Includes ARO related to wind farms.

Jointly-owned Electric Facilities

SWEPCo has electric facilities that are jointly-owned with affiliated and nonaffiliated companies. Using its own financing, SWEPCo is obligated to pay its share of the costs of these jointly-owned facilities in the same proportion as its ownership interest. SWEPCo's proportionate share of the operating costs associated with these facilities is included in its statements of income and the investments and accumulated depreciation are reflected in its balance sheets under Utility Plant as follows:

	Fuel Type	Percent of Ownership	Registrant's Share as of December 31, 2023 Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
Flint Creek Generating Station, Unit 1 (a)	Coal	50.0 %	$ 402.8	$ 1.6	$ 167.5
Pirkey Plant, Unit 1 (a)(d)	Lignite	85.9 %	—	—	—
Turk Generating Plant (a)(e)	Coal	73.3 %	1,504.0	10.1	323.3
North Central Wind Energy Facilities (b)(c)	Wind	54.5 %	1,086.3	2.9	67.9
Total			$ 2,993.1	$ 14.6	$ 558.7

	Fuel Type	Percent of Ownership	Registrant's Share as of December 31, 2022 Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
Flint Creek Generating Station, Unit 1 (a)	Coal	50.0 %	$ 382.9	$ 16.4	$ 149.4
Pirkey Plant, Unit 1 (a)	Lignite	85.9 %	632.0	—	632.0
Turk Generating Plant (a)	Coal	73.3 %	1,611.1	5.1	314.7
North Central Wind Energy Facilities (b)(c)	Wind	54.5 %	1,066.8	10.1	35.2
Total			$ 3,692.8	$ 31.6	$ 1,131.3

(a) Operated by SWEPCo.
(b) Operated by PSO.
(c) PSO and SWEPCo own undivided interests of 45.5% and 54.5% of the NCWF, respectively.
(d) Pirkey Plant was retired in March 2023. See "Coal-Fired Generation Plants" of Note 5 for additional information.
(e) Includes impact of regulatory disallowance of AFUDC. See "2012 Texas Base Rate Case" section of Note 4 for additional information.

17. 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 SWEPCo

	Years Ended December 31, 2023	2022
	(in millions)	
Retail Revenues:		
Residential Revenues	$ 746.0	$ 850.3
Commercial Revenues	558.9	643.7
Industrial Revenues	358.9	437.1
Other Retail Revenues	10.1	10.1
Total Retail Revenues	1,673.9	1,941.2
Wholesale Revenues:		
Generation Revenues (a)	191.0	319.0
Transmission Revenues (a)	150.8	148.7
Total Wholesale Revenues	341.8	467.7
Other Revenues from Contracts with Customers (a)	29.2	24.6
Total Revenues from Contracts with Customers	2,044.9	2,433.5
Other Revenues:		
Alternative Revenues	(9.4)	1.2
Other Revenues	(0.5)	0.4
Total Other Revenues	(9.9)	1.6
Total Operating Revenues	$ 2,035.0	$ 2,435.1

(a) Amounts include affiliated and nonaffiliated revenues.

Performance Obligations

SWEPCo 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. SWEPCo 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 SWEPCo are summarized as follows:

Retail Revenues

SWEPCo 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 SWEPCo 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

SWEPCo has performance obligations to sell electricity to wholesale customers from generation assets in SPP. 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.

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.

Wholesale Revenues - Transmission

SWEPCo has performance obligations to transmit electricity to wholesale customers through assets owned and operated. The performance obligation to provide transmission services in SPP 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 monthly for SPP.

SWEPCo 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.

PSO, SWEPCo and AEPSC are parties to the TCA by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. Affiliate revenues as a result of the TCA are reflected as Transmission Revenues in the disaggregated revenues table above.

Contract Assets and Liabilities

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

When SWEPCo 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. SWEPCo's contract liabilities typically arise from services provided under joint use agreements for utility poles. SWEPCo 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 SWEPCo's balance sheets within the Customer Accounts Receivable line item. SWEPCo'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 14 for additional information.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable from Associated Companies on SWEPCo's balance sheets were $27 million and $19 million, as of December 31, 2023 and 2022.

Contract Costs

Contract costs to obtain or fulfill a contract for SWEPCo 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. SWEPCo did not have material contract costs as of December 31, 2023 and 2022.

Name of Respondent: SWEPCO	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				5,357,106	1,396,397		6,753,503		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				(19,519,239)	126,487		(19,392,752)		
3	Preceding Quarter/Year to Date Changes in Fair Value				8,638,260	(210,979)		8,427,280		
4	Total (lines 2 and 3)				(10,880,979)	(84,492)		(10,965,472)	290,060,102	279,094,630
5	Balance of Account 219 at End of Preceding Quarter/Year				(5,523,873)	1,311,905		(4,211,969)		
6	Balance of Account 219 at Beginning of Current Year				(5,523,873)	1,311,905		(4,211,969)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				(6,841,691)	451,388		(6,390,304)		
8	Current Quarter/Year to Date Changes in Fair Value				7,449,215	(264,013)		7,185,202		
9	Total (lines 7 and 8)				607,523	187,375		794,898	220,288,485	221,083,383
10	Balance of Account 219 at End of Current Quarter/Year				(4,916,350)	1,499,279		(3,417,070)		

Name of Respondent: SWEPCO	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)	10,363,004,814	10,363,004,814					
4	Property Under Capital Leases	154,665,733	154,665,733					
5	Plant Purchased or Sold	64,005	64,005					
6	Completed Construction not Classified	600,082,550	600,082,550					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	11,117,817,102	11,117,817,102					
9	Leased to Others							
10	Held for Future Use	1,472,845	1,472,845					
11	Construction Work in Progress	560,906,375	560,906,375.00					
12	Acquisition Adjustments	18,043,976	18,043,976					
13	Total Utility Plant (8 thru 12)	11,698,240,298	11,698,240,298					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	3,036,989,283	3,036,989,283					
15	Net Utility Plant (13 less 14)	8,661,251,015	8,661,251,015					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	2,926,471,520	2,926,471,520					
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	92,474,216	92,474,216					
22	Total in Service (18 thru 21)	3,018,945,736	3,018,945,736					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation	(429)	(429)					
29	Amortization							
30	Total Held for Future Use (28 & 29)	(429)	(429)					
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	18,043,976	18,043,976					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	3,036,989,283	3,036,989,283					

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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: SWEPCO	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	12,202					12,202
3	(302) Franchise and Consents						
4	(303) Miscellaneous Intangible Plant	180,057,803	30,951,871	22,964,407			188,045,267
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	180,070,005	30,951,871	22,964,407			188,057,469
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	25,389,217		355,043		(5,843,028)	19,191,146
9	(311) Structures and Improvements	597,145,964	21,533,354	109,850,953			508,828,365
10	(312) Boiler Plant Equipment	2,486,275,961	8,945,211	390,896,862			2,104,324,310
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	694,529,331	13,503,478	59,160,499			648,872,310
13	(315) Accessory Electric Equipment	233,572,020	969,645	18,615,373			215,926,292
14	(316) Misc. Power Plant Equipment	204,263,819	1,256,787	20,337,730			185,182,876
15	(317) Asset Retirement Costs for Steam Production	94,664,917	1,967,616	41,736,705			54,895,828
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	4,335,841,229	48,176,091	640,953,165		(5,843,028)	3,737,221,127
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						
20	(322) Reactor Plant Equipment						
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights						
28	(331) Structures and Improvements						
29	(332) Reservoirs, Dams, and Waterways						
30	(333) Water Wheels, Turbines, and Generators						
31	(334) Accessory Electric Equipment						
32	(335) Misc. Power Plant Equipment						
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)						
36	D. Other Production Plant						
37	(340) Land and Land Rights	3,051,738	87,290	42,896			3,096,132
38	(341) Structures and Improvements	31,437,765	319,007	72,533			31,684,239
39	(342) Fuel Holders, Products, and Accessories						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
40	(343) Prime Movers						
41	(344) Generators	1,126,440,182	22,825,990	3,755,840			1,145,510,332
42	(345) Accessory Electric Equipment	9,121,090	4,239,542	1,858,367			11,502,265
43	(346) Misc. Power Plant Equipment	1,872,449	565,294	1			2,437,742
44	(347) Asset Retirement Costs for Other Production	24,544,414					24,544,414
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,196,467,638	28,037,123	5,729,637			1,218,775,124
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	5,532,308,867	76,213,214	646,682,802		(5,843,028)	4,955,996,251
47	3. Transmission Plant						
48	(350) Land and Land Rights	114,818,735	3,452,724			220,915	118,492,374
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	54,535,029	22,540,244	338,292			76,736,981
50	(353) Station Equipment	844,576,492	78,644,769	15,145,350			908,075,911
51	(354) Towers and Fixtures	36,359,565	388,904	676,118			36,072,351
52	(355) Poles and Fixtures	926,246,081	85,754,363	13,194,264			998,806,180
53	(356) Overhead Conductors and Devices	499,316,458	23,672,207	6,222,295			516,766,370
54	(357) Underground Conduit	11,497,974	3,064,618				14,562,592
55	(358) Underground Conductors and Devices	827,587	196,663				1,024,250
56	(359) Roads and Trails	131,947					131,947
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,488,309,868	217,714,492	35,576,319		220,915	2,670,668,956
59	4. Distribution Plant						
60	(360) Land and Land Rights	10,072,800	158,433				10,231,233
61	(361) Structures and Improvements	13,936,304	753,177	14,201		27,173	14,702,453
62	(362) Station Equipment	404,772,008	32,779,801	3,193,055		22,047	434,380,801
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	555,771,025	32,856,162	4,018,353			584,608,834
65	(365) Overhead Conductors and Devices	548,979,262	32,338,300	5,067,878			576,249,684
66	(366) Underground Conduit	84,804,717	6,581,450	36,244			91,349,923
67	(367) Underground Conductors and Devices	266,677,543	16,059,270	926,133			281,810,680
68	(368) Line Transformers	466,612,771	41,544,972	8,115,638			500,042,105
69	(369) Services	112,329,541	5,408,173	230,070			117,507,644
70	(370) Meters	106,861,945	24,294,693	15,041,738		(22,047)	116,092,853
71	(371) Installations on Customer Premises	49,412,214	5,101,652	2,718,734			51,795,132
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	51,308,846	6,637,007	2,424,428			55,521,425
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,671,538,976	204,513,090	41,786,472		27,173	2,834,292,767
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	23,416,750	489,593	369,879		(15,183,883)	8,352,581
87	(390) Structures and Improvements	111,625,191	8,182,462	1,582,313		(27,173)	118,198,167
88	(391) Office Furniture and Equipment	7,293,106	933,741	1,196,755			7,030,092
89	(392) Transportation Equipment	3,875,443					3,875,443
90	(393) Stores Equipment	3,361,104	203,439	13,282			3,551,261
91	(394) Tools, Shop and Garage Equipment	32,596,324	2,189,215	275,149			34,510,390
92	(395) Laboratory Equipment	5,197,160		79,615			5,117,545

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	698,227	41,936				740,163
94	(397) Communication Equipment	88,077,244	24,863,767	1,487,886			111,453,125
95	(398) Miscellaneous Equipment	3,493,438	627,109	33,298			4,087,249
96	SUBTOTAL (Enter Total of lines 86 thru 95)	279,633,987	37,531,262	5,038,177		(15,211,056)	296,916,016
97	(399) Other Tangible Property	80,514,545		24,505		(64,600,074)	15,889,966
98	(399.1) Asset Retirement Costs for General Plant	1,265,939					1,265,939
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	361,414,471	37,531,262	5,062,682		(79,811,130)	314,071,921
100	TOTAL (Accounts 101 and 106)	11,233,642,187	566,923,929	752,072,682		(85,406,070)	10,963,087,364
101	(102) Electric Plant Purchased (See Instr. 8)	64,005					64,005
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)	11,233,706,192	566,923,929	752,072,682		(85,406,070)	10,963,151,369

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ELECTRIC PLANT LEASED TO OTHERS (Account 104)

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

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ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Cardnell Road 138KV Substation (1062)	05/01/2009	12/31/2024	393,043.00
3	McCann Road 138/35kV Substation (1225)	06/01/2022	12/31/2024	649,660
4	Items under $250,000			430,142.00
21	Other Property:			
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47	TOTAL			1,472,845

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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	200MW SWEPCO Diversion Wind	3,303,479.00
2	598MW SWEPCo Wagon Wheel	5,594,665.00
3	ADMS Imp DSN DNEX-SWP D	5,732,305.00
4	AMI SWEPCO Arkansas	3,944,299.00
5	Arsenal Hill Non-TX CI	14,592,838.00
6	Arsenal Hill TX CI	7,497,342.00
7	Ashdown to 12th St Non-TX CI	5,339,010.00
8	Ashdown to 12th St TX CI	2,742,418.00
9	Bann - Texarkana Ops Non-TX CI	4,071,721.00
10	Bann to Texarkana Ops TX CI	2,091,381.00
11	Bentonville Non-TX CI	3,098,049.00
12	Bentonville Non-TX CI Shadow	1,591,454.00
13	Blanchard - N Market Non-TX CI	1,869,511.00
14	Bloomburg to Texark Non-TX CI	1,882,334.00
15	Booneville to Branch non-tx CI	9,272,147.00
16	Booneville to Branch TX CI	4,762,883.00
17	Bullock Non-TX Trans CI	1,723,710.00
18	Bullock Station D CI	4,238,502.00
19	CARDNELL RD - D-LINE	1,930,953.00
20	CARDNELL RD - D-Station Comp	10,897,098.00
21	CI 111 shadow for CI 194	1,571,201.00
22	CI 194	3,058,770.00
23	CI Eureka shadow	1,617,278.00
24	CIS-Common Deployment-SWP D	4,802,274.00
25	Corp Prgrm Billing-SWEPCO Tran	1,812,188.00
26	D/SW/Capital Blanket - SWEPCo	3,024,310.00
27	DA Distribution Station - Ark	3,945,960.00
28	DA Distribution Station - TX	2,725,253.00
29	Daingerfield-MtPleas non-tx CI	1,563,012.00
30	Diana to Lone Star S Non-TX CI	1,913,263.00
31	Dierks to Mena 111 CI	3,027,385.00
32	Dierks to Mena 194 CI	5,893,578.00
33	distr work	1,811,012.00
34	Ed-Ci-Sepco-D Ast Imp	13,077,598.00
35	Ed-Ci-Sepco-D Cust Serv	5,044,669.00
36	Ed-Ci-Sepcotx-D Ast Imp	4,391,903.00
37	Ed-Ci-Sepcotx-D Cust Serv	1,185,305.00
38	Eureka Springs - D-station	1,041,601.00
39	Eureka Springs 3 Terminal	3,153,124.00
40	Gilmer to Pittsburg Non-TX CI	3,169,233.00
41	Gilmer to Pittsburg TX CI	1,627,690.00
42	Jefferson - Superior non-TX CI	1,772,547.00
43	Knox Lee - Rock Hill Non TX CI	5,734,215.00
44	Knox Lee to Rock Hill TX CI	2,945,739.00
45	KXL U5 Control Sys Replacement	1,594,239.00
46	Lake Paul - W Child non-TX CI	12,772,653.00
47	Lake Pauline-Red Riv Non-TX CI	1,224,163.00

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
48	Lake Paul-W Child TX CI	6,561,260.00
49	Longview T 2023 TTMP CI	1,152,980.00
50	Longwood-ElDorado Non-TX CI	23,296,671.00
51	Longwood-ElDorado TX CI	11,969,334.00
52	N Magaz to W Boonev Non-TX CI	5,832,778.00
53	N Magazine to W Boonev TX CI	2,996,436.00
54	Natchitoches Land Purchase	2,047,253.00
55	NCEF-CI-SWEPCo-G-PPB	1,899,713.00
56	NGUCS/Radio SWEPCO Valley Impr	10,068,269.00
57	Pirkey Solar Land Purchase	3,910,284.00
58	Pirkey to Scotsville non-tx CI	1,885,724.00
59	Red Point Non-TX CI	5,656,320.00
60	Red Point TX CI	2,906,038.00
61	Sabine - D-Station	8,000,975.00
62	SABINE - T-Station-	1,178,265.00
63	Scottsville Station D CI	3,596,961.00
64	SCR Catalyst Layer 1 Replace	1,740,340.00
65	SEP-D Telecom	4,050,618.00
66	SEPT-D Telecom	2,160,041.00
67	SHADOW CI	2,487,403.00
68	Shreveport Service Center(New)	6,830,966.00
69	SHREVEPORT TOC	63,081,901.00
70	Shreveport TOC - GL 111	32,409,931.00
71	Ss-Ci-Sepco-D Gen Plt	2,585,938.00
72	Ss-Ci-SepcoTx-D Gen Plt	1,343,685.00
73	SW-D BlnktProj Under $3M	2,083,873.00
74	SWEPCo Distr Pre Eng Parent	2,139,341.00
75	SWEPCo Distr Pre Eng Parent	5,985,397.00
76	SWEPCo Major Eq/Spares-Distr	2,666,719.00
77	SWEPCo Trans Pre Eng Parent	3,955,861.00
78	SWEPCO Transmission	4,832,809.00
79	SWEPCo TX-D Serv Restoratn Blk	8,944,268.00
80	SWEPCO: Clarendon-NW Memphis	1,086,485.00
81	SWEPCo-D Servc Restoration Bl	12,470,606.00
82	SWEPCo-D Spare/Major Equip CI	3,856,170.00
83	SWEPCo-D-Tx Spare/Mjr Equip CI	2,345,563.00
84	SW-T BlnktProj Under $3M	10,495,545.00
85	SW-T BlnktProj Under$3M-Shadow	5,578,911.00
86	T Sep T Anda	1,233,664.00
87	T/SW/Capital Blanket - SWEPCo	1,582,146.00
88	Trans Station Failures- SWEPCo	2,128,360.00
89	Transmission Work	3,764,533.00
90	Transmission Work	1,924,504.00
91	TRK OVATION CONTROLS REPLACE	3,665,344.00
92	Turk Rail Replacement 2023-25	1,753,749.00
93	Wallace L-IPC Mansf Non-TX CI	2,731,302.00
94	Wallace L-IPC Mansf TX CI	1,403,096.00
95	WS Spare Generator Winding Kit	3,940,928.00
96	WS-CI-SEPCo-G PPB	14,901,022.00
97	WSH U1 BAG REPL BAGHOUSE	2,699,191.00
98	Other Minor Projects Which is under 5% or $1,000,000	51,410,642.00
43	Total	560,906,375.00

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

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

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

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	3,318,101,929	3,318,102,358	(429)	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	302,157,503	302,157,503		
4	(403.1) Depreciation Expense for Asset Retirement Costs	2,162,759	2,162,759		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts	3,910,495	3,910,495		
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	1,980,736	[(a)] 1,980,736		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	310,211,493	310,211,493		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(725,457,565)	(725,457,565)		
13	Cost of Removal	(36,694,506)	[(b)] (36,694,506)		
14	Salvage (Credit)	6,853,691	[(c)] 6,853,691		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(755,298,380)	(755,298,380)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	53,456,049	53,456,049		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,926,471,091	2,926,471,520	(429)	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,188,424,534	1,188,424,534		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	110,470,773	110,470,773		
25	Transmission	650,125,941	650,125,941		
26	Distribution	857,957,527	857,957,956	(429)	
27	Regional Transmission and Market Operation				
28	General	119,492,316	119,492,316		
29	TOTAL (Enter Total of lines 20 thru 28)	2,926,471,091	2,926,471,520	(429)	

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FOOTNOTE DATA

(a) Concept: OtherAccounts

Depr Exp classified to acct 1510001	$ 833,920
Ash Pond Exp account 1823099	$ (5,093)
Louisiana ARO asbestos depr exp	$ 590,684
Louisiana ARO ash pond depr exp	$ 561,225
Total	$ 1,980,736

(b) Concept: CostOfRemovalOfPlant

Includes $10,104,243 of removal cost in retirement work in progress (RWIP).

(c) Concept: SalvageValueOfRetiredPlant

Includes ($4,421,710) of salvage in retirement work in progress (RWIP).

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

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1	Southwest Arkansas Utilities Corp. 100 shares, $100 par value							
2	common stock	03/24/2028		10,000			10,000	
3	Dolet Hills Lignite Company (1)	06/01/2001						
4	Investment - Dolet Hills			8,087,121			8,087,121	
5	Dividends - Dolet Hills			(20,215,155)			(20,215,155)	
6	Equity in Undistributed Earnings - Dolet Hills			20,138,053	1,388,307	(1,325,210)	20,201,149	
7	Oxbow Lignite Company, LLC (2)	12/29/2009						
8	Investment - Oxbow Lignite			12,872,791			12,872,791	
9	Additional Investments (2016 Cash Infusion)			5,473,685			5,473,685	
10	Dividends - Oxbow Lignite			(16,274,183)		(171,021)	(16,445,204)	
11	Capital Contributions to Subs							
12	Mutual Energy SWEPCO, LLC	08/21/2015		1,429		1,599	3,028	
13	Investment - Mutual Energy			1,943,764			1,943,764	
14	Equity in Undistributed Earnings - Mutual Energy			162,374	95,726		258,101	
42	Total Cost of Account 123.1 $		Total	12,199,879	1,484,033	(1,494,632)	12,189,280	

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

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	64,682,162	[(a)]110,249,718	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	2,463,830	3,582,634	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	39,070,797	49,525,860	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	43,956,593	33,190,144	Electric
8	Transmission Plant (Estimated)	159,522	37,721	Electric
9	Distribution Plant (Estimated)	1,267,460	1,200,921	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	678,397	[(b)]217,606	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	85,132,769	[(c)]84,172,252	
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)	1,700	1,700	
17				
18				
19				
20	TOTAL Materials and Supplies	152,280,461	198,004,604	

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FOOTNOTE DATA

(a) Concept: FuelStock
Formula Rate uses 13 month average.
(b) Concept: PlantMaterialsAndOperatingSuppliesOther
Assigned to - Other: Includes Customer Accounts and Administrative and General Expenses (applies to both beginning and ending balances).
(c) Concept: PlantMaterialsAndOperatingSupplies
Formula Rate uses 13 month average. Production materials and supplies are identified by a query of the general ledger system.

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Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	758,209.00		72,752.00		72,752.00		72,752.00		1,875,024.00		2,851,489.00	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	93,930.00		28,406.00						64,489.00		186,825.00	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9	Unknown												
10	Other												
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	20,389.00										20,389.00	
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Surrenders												
23	Consent Decree Surrenders												
24	Unknown												
25	Other												
26													
27													
28	Total												
29	Balance-End of Year	831,750.00		101,158.00		72,752.00		72,752.00		1,939,513.00		3,017,925.00	
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains		49										49
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.	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												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

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Name of Respondent: SWEPCO	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		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	5,862.00	2,725,867	3,646.00								9,508.00	2,725,867
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	1,433.00		632.00								2,065.00	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9	Fathom Energy LLC	(322.00)	(1,850,620)									(322.00)	(1,850,620)
10	Other												
11	Total Purchases	(322.00)	(1,850,620)									(322.00)	(1,850,620)
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	4,388.00	509,682									4,388.00	509,682
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Luminant Generation Company LLC												
23	Surrenders												
24	Birchwood Power Partners, L.P.												
25	Wolverine Power Supply Cooperative, Inc.												
26	Allegheny Energy Supply Company, LLC												
27	Consent Decree Surrenders												
28	Total												
29	Balance-End of Year												
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)	2,585.00	365,565	4,278.00								6,863.00	365,565
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												
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Name of Respondent: SWEPCO	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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

Name of Respondent: SWEPCO	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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent: SWEPCO	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**				
20	Total				
21	**Generation Studies**				
22	STALL UPRATE APPLICATION	50,000	183		
23	STALL UPRATE DEPOSIT	184,000	183		
39	Total	234,000			
40	Grand Total	234,000			

Name of Respondent: SWEPCO	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	Estimated fuel disallowance.		12,025,320	182, 431	23,025,320	(11,000,000)
2	2021 Winter Storm carrying costs on unrecovered fuel costs related to the Arkansas portion of SWEPCO 2021 Winter Storm, Order 21 in APSC Docket 19-008-U	1,914,068	859,382	182, 431	2,773,450	
3	Advanced Metering System (AMS) Deployment Plan for SWEPCO TX - O/U and Carry Charges, Docket No. 52389	4,641,561	16,397,962	182, 254, 403, 407, 431	17,710,497	3,329,026
4	Amortize approved Arkansas COVID Expenses per over a 5 year period, APSC Docket No. 21-070-U, Amortization Period: 07/2022 - 2027	1,669,151		426	370,922	1,298,229
5	Arkansas retail share of the Dolet Hills Net Book Value regulatory asset, APSC Docket No. 21-070-U	22,499,714	571,899	182, 407	4,899,563	18,172,050
6	Asset Retirement Obligation - Ash Ponds - SFAS 143	12,229,839	240,612	175, 244, 254	12,076,115	394,336
7	COVID-19 Deferred Expense	4,316,257	1,609,420	407, 426	1,489,166	4,436,511
8	Defer TX Line Inspection Costs	1,574,571	343,983	182	8,503	1,910,051
9	Deferral of Fuel Underrecovery - Arkansas	65,833,246	22,333,035	182, 254, 440, 442, 444, 557	53,914,341	34,251,940
10	Deferral of Fuel Underrecovery - Texas	191,403,604	9,827,747	182, 254, 440, 442, 444, 557	165,117,977	36,113,374
11	Deferred Arkansas Environmental Chemical Costs, Docket No. 14-080-U 2	1,486,598		502	743,299	743,299
12	Deferred O&M Expenses related to City of Shreveport Sewer Work for recovery over 15 months, LPSC Docket No. U-32220 Approved Feb 2016, LPSC Docket No. U-34200, Amortization Period: 05/2017-2018	1,791,238	65,963	593	373,175	1,484,026
13	Deferred Storm Expense	151,467,969	2,297,605	571	3,442,856	150,322,718
14	Disallowance of the Arkansas portion of the Dolet Hills Plant, APSC Docket No. 21-070-U	(1,349,333)	520,488			(828,845)
15	Disallowance of the Texas portion of the Dolet Hills Plant, PUCT Docket 51415	(10,767,874)	800,129			(9,967,745)
16	Dolet Hills Fuel-Deferred AR	8,867,644		182	4,092,759	4,774,885
17	Dolet Hills Fuel-Deferred LA	32,049,844	3,365,561			35,415,405
18	Environmental CWIP	7,805,101	(1)	182, 512	540,514	7,264,586
19	Louisiana 2013 Formula Rate Plan (FRP) Excess Refunds	936,507				936,507
20	Reg Asset-Mattison	2,204,984	113,980	182, 407	780,540	1,538,424
21	NOLC Reg Asset-Equity Carrying	(23,868,521)	15,543,152	182	14,060,760	(22,386,129)
22	NOLC Regulatory Assets	23,868,521	14,060,760			37,929,281
23	North Central Wind.over/under recovery of the WFA Rider	6,362,484	35,261,507	403	21,402,845	20,221,146
24	SFAS 106 Medicare Subsidy, Amortization Period: 01/2013 - 12/2024	1,066,618		926	533,310	533,308
25	SFAS 109 Deferred FIT	58,419,948	64,678,602	282	75,759,139	47,339,411
26	SFAS 109 Deferred SIT	208,710,103	74,453,749	283	44,583,914	238,579,938
27	SFAS No. 158 - Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans	88,716,119	103,961,604	129, 190, 219, 228	92,757,890	99,919,833
28	Surcharge for the excess winter storm expenses for Arkansas, Louisiana, and Texas	132,403,876	2,085,427	182, 440, 442, 444, 557	32,611,475	101,877,828
29	SWEPCO Arkansas bad debt expense under base rates, Docket No. 21-070-U	4,193,622	2,318,722			6,512,344
30	Texas retail share of the Dolet Hills Net Book Value regulatory asset, PUCT Docket 51415	43,912,891	277,408	182, 407	2,313,372	41,876,927
31	Texas retail share of the retired gas units: Lieberman U2, Lone Star U1, and Knox Lee U2-4 net book value regulatory asset, PUCT Docket 51415	3,599,963		407	1,222,368	2,377,595
32	Transmission Base Plan Funding FERC Formula Rates Under Recovery	907,418		456	907,420	(2)
33	Underrecovered Environmental Adjustment Clause - Louisiana	268,056	573,619	509	841,675	
34	Underrecovery of Energy Efficiency Program Expenses - Texas	3,727,630	2,874,148	440, 442, 444, 907, 908	5,822,063	779,715
35	Unrealized Loss on Forward Commitments		15,736,092	244	348,102	15,387,990
36	Unrecov Fuel Cost 2021 Weather	194,675,259	14,924,159	182, 440, 442, 444, 557	58,235,793	151,363,625

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
37	Various Rate Case Expenses and amortizations approved from State Commission Authorities	9,168,869	2,618,153	928	2,020,844.00	9,766,178
38	Welsh Power Plant Unit 2 Asbestos ARO Texas Portion - to be amortized over 24 years, PUCT Docket No. 46449	459,237		407	33,704.00	425,533
39	Welsh Power Plant Unit 2 Texas Portion - Recovery of Retired Undepreciated Balance, PUCT Docket No. 46449	14,982,073	(1)	407	564,554.00	14,417,518
40	Welsh/Flint Creek Power Plants - Environmental Deferral - Amortized over 15 Years, LPSC Docket No. U-34200, Amortization Period: 05/2017 - 2032	9,973,521	574,819	182, 403, 408, 431	1,643,410.00	8,904,930
41	Incremental Storm Cost Related to the 2023 Thunder Storm to the Catastrophe Reserve		134,764,542	228, 560, 566, 570, 571, 583, 588, 593	81,388,213	53,376,329
42	Dolet LA Share Undeprec Bal		45,721,486	182, 407	4,912,275	40,809,211
43	Pirkey LA Share Undeprec Bal		68,705,099	182, 407	2,897,337	65,807,762
44	Pirkey AR Share Undeprec Bal		35,285,687	108, 154	53,744	35,231,943
45	LA Storm Carrying Charges		15,623,801	431	18,570,197	(2,946,396)
46	SWEPCO TX Fuel Mine Costs		82,498,333	182, 419	1,647,423	80,850,910
47	Trans BPF		933,108		933,108	
48	Louisiana AMS Und Recov Asset		19,564	182	19,564	
49	Louisiana AMS Regulatory Asset		444,286	407	444,286	
50	LA AMS Def Equity Asset		9,938			9,938
44	TOTAL	1,282,122,376	805,320,849		757,887,782	1,329,555,443

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MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS
				Credits Account Charged (d)
1	Agency Fees - Factored Accounts Receivable	3,879,567	38,517,835	142/184/234/426
2	Associated Business Development Billings and Deferred Projects	2,375,170	59,952,660	107/108/143/151/154/163/183/184/186/232/234/236/242/502/506/510/511/512/514/553/921/928
3	Unamortized Credit Line Fees Amortization	661,530	516,717	146/243/431
4	Sabine Mine Preparation - Rusk County, TX - Amortization based on tons mined	32,814	42,833	108/151
5	Deferred Expenses - Disposition of Fuel	245,131	4,047,909	151/152/154/183/501/547
6	Deferred Expense - Underrecovery of Transsource Missouri	124,564	358,356	146/184/236/242/408/506/565/588/921
7	Deferred Rate Case Expense	88,984	1,089,187	107/108/146/154/163/165/181/184/186/232/234/236/241/242/408/421/570/588/593/903/928/930
8	Deferred Leased Assets	69,878	1,233,474	107/108/142/146/154/184/186/232/234/235/236/237/426/580/583/586/588/593/901/907/921/923/925/928/935
9	Dolet Hills and Sabine Reclamation Advance	54,797,984	771,105,751	107/108/143/151/152/154/163/183/184/186/232/234/236/242/500/501/502/506/510/511/512/513/514/925
10	Deferred Lignite Lease			
11	Minor Items < $100,000	26,375	674,192	107/108/131/142/146/163/184/185/186/232/234/235/236/242/253/408/426/566/580/582/583/584/585/586/587/588/593/594/596/597/598/901/902/903/90
12	Provision for refund related to overcollection of 2022 SPP revenue	7,347,651	29,269,762	456/565
47	Miscellaneous Work in Progress			
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)			
49	TOTAL	69,649,648		

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ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Nol-State C/F-Def Tax Asset-L/T - La	65,062,625	63,543,068
3	Accrd Book Aro Expense - Sfas 143	54,023,608	60,107,886
4	Disallowed Costs-Turk Plant	31,930,824	29,706,999
5	Tax Credit C/F - Def Tax Asset	30,077,210	31,284,917
6	Nol-State C/F-Def Tax Asset-L/T - Ar	25,820,162	26,269,825
7	Other	(41,092,872)	(4,081,890)
8	TOTAL Electric (Enter Total of lines 2 thru 7)	165,821,557	206,830,805
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	192,397,009	206,055,079
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	[a]358,218,566	412,885,884

Notes

Name of Respondent: SWEPCO	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

Formula Rate uses 13 month average.

Line 17 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Acc Def Income Taxes - Federal - Hdg-CF-Int Rate	0	-
Non Utility Items - 190.2	626557	-6486
SFAS 109-Regulatory Assets - 190.3, 190.4 & 190.6	190302081	204754688
SFAS 133	-	-
Accu Def Income Taxes Pension-OCI	1468371	1306877
Total	192397009	206055079

Line 18

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

Balance at Beginning of Year	358218566
(Less) Amounts Debited to:	
(a) Account 410.1	-36069739
(b) Account 410.2	-3161348
(c) 1823/254/219/129/427	-17369657
(Plus) Amounts Credited to:	
(a) Account 411.1	77078987
(b) Account 411.2	2528305
(c) 1823/254/219/129/427	31660769
Balance at End of Year	412885883

Name of Respondent: SWEPCO	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	Common Stock (Account 201)	7,600,000	18.00		3,680	66,240				
7	Total	7,600,000			3,680	66,240				
8	Preferred Stock (Account 204)									
9										
10										
11										
12	Total									
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: SWEPCO	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	630,000,000
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	50,000,000
4	Ending Balance Amount	680,000,000
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	2,106,937
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	2,106,937
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	810,038,473
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	1,599
16	Ending Balance Amount	810,040,072
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	1,492,147,009

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CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	437

Name of Respondent: SWEPCO	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											
3											
4											
5	Subtotal										
6	Reacquired Bonds (Account 222)										
7											
8											
9											
10	Subtotal										
11	Advances from Associated Companies (Account 223)										
12											
13											
14											
15	Subtotal										
16	Other Long Term Debt (Account 224)										
17	Senior Unsecured Notes Series H, 6.20%		350,000,000		3,509,108		147,000	03/15/2010	03/15/2040	03/15/2010	03/15/2040
18	[(a)] Senior Unsecured - Series P, 5.30%		350,000,000		2,889,534		458,500	03/30/2023	04/01/2033	03/30/2023	04/01/2033
19	Senior Unsecured Notes Series J, 3.90%		400,000,000		3,980,775		3,568,000	03/26/2015	04/01/2045	03/26/2015	04/01/2045
20	Senior Unsecured Notes Series K, 2.75%		400,000,000		2,925,034		416,000	09/29/2016	10/01/2026	09/29/2016	10/01/2026
21	Senior Unsecured Notes Series L, 3.85% FERC Authority ES17-43-000		450,000,000		4,656,209		958,500	01/22/2018	02/01/2048	01/22/2018	02/01/2048
22	Senior Unsecured Notes Series M, 4.10% FERC Authority ES18-32-000		575,000,000		4,369,257			09/13/2018	09/15/2028	09/13/2018	09/15/2028
23	Senior Unsecured - Series N, 1.65%		500,000,000		3,903,793		50,000	03/15/2021	03/15/2026	03/15/2021	03/15/2026
24	Senior Unsecured - Series O, 3.25%		650,000,000		6,790,998		2,346,500	11/01/2021	11/01/2051	11/01/2021	11/01/2051
25	Senior Unsecured Notes - Financial Hedges										
26	Subtotal										
33	TOTAL		3,675,000,000								

Line No.	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17	350,000,000	21,700,000
18	350,000,000	13,964,028
19	400,000,000	15,600,000
20	400,000,000	11,000,000
21	450,000,000	17,325,000
22	575,000,000	23,575,000
23	500,000,000	8,250,000
24	650,000,000	21,125,000
25		(334,194)
26	3,675,000,000	
33	3,675,000,000	132,204,834

Name of Respondent: SWEPCO	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: ClassAndSeriesOfObligationCouponRateDescription
In March 2023, new Issuance for SWEPCO Series P Unsecured Notes 5.30% for $350,000,000 with maturity date April 2033.

Name of Respondent: SWEPCO	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)	220,288,485
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](151,380,943)
28	Show Computation of Tax:	
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Name of Respondent: SWEPCO	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

	In (000's)
Net Income for the Year per Page 117	220,288
Federal Income Taxes	(29,261)
State Income Taxes	(5,079)
Pre-Tax Book Income	185,948
Allowance for Funds Used During Construction and Other Differences:	
Between Items Capitalized for Books and Expensed for Tax	(8,765)
Accrued Company-wide Incentive Plan	(10,534)
Book / Tax Unit of Property Adj	(126,600)
Capitalized Relocation Costs	(1,236)
Capitalized Software	11,570
Deferred Fuel Costs (Net)	186,872
Disallowed Costs - Turk Plan	84,143
Disallowed Costs - PUCT	(2,169)
Equity in Earnings of Subsidiary Companies	(1,484)
Excess Tax Vs Book Depreciation	(131,152)
Depletion	(31,185)
Mark to Market	(116)
Mine Reclamation	(209)
Pension Expenses (Net)	12,396
Premium / Loss on Reacquired Debt (Net)	600
Provision for Revenue Refund	190
Regulatory Assets	(222,587)
Removal Costs	(33,261)
SFAS 106 - Post Retirement Benefit Expense Accrued / Funded (Net)	(5,498)
SFAS 112 - Post Employment Benefit Expense Accrued / Funded (Net)	(1,401)
Unbilled Revenue	—
Others	(56,446)
Taxable Income before State Taxes	(150,924)
State & Local Current Tax	456
Federal Taxable Income	(151,380)
Computation of Tax:	
FIT on Current Year Taxable Income @ 21%	(31,790)
Other	—
NOL Deferred Tax Asset	—
Tax Credits	267
Parent Savings	67,053
Alt Min	(4,170)
R and D Credit	248
Estimated Tax Currently Payable (a)	(95,188)
Adjustments of Prior Year's Accruals	
Tax Expense for R/C of Net Operating Loss (Prior Yr)	
Estimated Current Federal Income Taxes	(95,188)

a) Represents the allocation of 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 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: SWEPCO	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 Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR	
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)
1	Federal Tax	Federal Tax			(12,870,355)	0	(51,065,735)	(42,524,661)	0	(21,411,429)	0
2	**Subtotal Federal Tax**				(12,870,355)	0	(51,065,735)	(42,524,661)	0	(21,411,429)	0
3	State Tax	State Tax	AR	2015	436	0	0	0	0	436	0
4	State Tax	State Tax	AR	2017	188,896	0	0	0	0	188,896	0
5	State Tax	State Tax	AR	2018	(72,598)	0	0	0	0	(72,598)	0
6	State Tax	State Tax	AR	2019	37,628	0	0	0	0	37,628	0
7	State Tax	State Tax	AR	2020	(3,112,111)	0	0	0	0	(3,112,111)	0
8	State Tax	State Tax	AR	2021	2,989,572		1,562,475	0		4,552,047	
9	State Tax	State Tax	AR	2022	(702,583)		0			(702,583)	
10	State Tax	State Tax	AR	2023			(765,229)			(765,229)	
11	State Tax	State Tax	LA	2015	(12,756)	0	0	0	0	(12,756)	0
12	State Tax	State Tax	LA	2017	1,332,321	0	0	0	0	1,332,321	0
13	State Tax	State Tax	LA	2018	637,467	0	0	0	0	637,467	0
14	State Tax	State Tax	LA	2019	2,769,914	0	0	0	0	2,769,914	0
15	State Tax	State Tax	LA	2020	(9,946,085)	0			0	(9,946,085)	0
16	State Tax	State Tax	LA	2021	4,473,171	0		0	0	4,473,171	0
17	State Tax	State Tax	LA	2022	(1,693,083)		0	0		(1,693,083)	
18	State Tax	State Tax	LA	2023			(246,230)			(246,230)	
19	State Tax	State Tax	MULTI	2019	899,200	0		0	0	899,200	0
20	State Tax	State Tax	MULTI	2020	(2,594)	0		0	0	(2,594)	0
21	State Tax	State Tax	MULTI	2021	(1,115,667)	0		0	0	(1,115,667)	0
22	State Tax	State Tax	NE	2017	0	0	0	0	0	0	0
23	State Tax	State Tax	NE	2018	(8,708)	0	0	0	0	(8,708)	0
24	State Tax	State Tax	NE	2019	(8,353)	0	0	0	0	(8,353)	0
25	State Tax	State Tax	NE	2020	(2,081)	0		0	0	(2,081)	0
26	State Tax	State Tax	NE	2021	6,000	0		0	0	6,000	0
27	State Tax	State Tax	NE	2022	(115,500)			0		(115,500)	
28	State Tax	State Tax	NE	2023				127,000		(127,000)	
29	State Tax	State Tax	OH	2020	3,071	0	1	0		3,072	0
30	State Tax	State Tax	OK	2017	8,947	0	0	0	0	8,947	0
31	State Tax	State Tax	OK	2018	(574)	0	0	0	0	(574)	0
32	State Tax	State Tax	OK	2019	17,768	0	0	0	0	17,768	0
33	State Tax	State Tax	OK	2020	(9,419)	0			0	(9,419)	0
34	State Tax	State Tax	OK	2021	(19,282)	0		0	0	(19,282)	0
35	State Tax	State Tax	OK	2022	2,687		0			2,687	
36	State Tax	State Tax	OK	2023			(3,436)			(3,436)	
37	State Tax	State Tax	TX	2011	(5,972)	0	0	0	0	(5,972)	0
38	State Tax	State Tax	TX	2017	0	0	0	0	0	0	0
39	State Tax	State Tax	TX	2018	12,274	0	0	0	0	12,274	0
40	State Tax	State Tax	TX	2019	821,601	0	0	0	0	821,601	0
41	State Tax	State Tax	TX	2020	(298,938)	0	0	0	0	(298,938)	0
42	State Tax	State Tax	TX	2021	302,317	0		0	0	302,317	0
43	State Tax	State Tax	TX	2022	(152,132)					(152,132)	
44	State Tax	State Tax	TX	2023			457,312			457,312	
45	**Subtotal State Tax**				(2,775,166)	0	1,004,893	127,000	0	(1,897,273)	0
46	Local Tax	Local Tax	LA				0	0		0	
47	Local Tax	Local Tax	LA	2022	2,357,112	23,367	23,367	2,357,112		0	
48	Local Tax	Local Tax	LA	2023			9,898,092	7,681,920		2,226,858	10,685
49	City Tax	Local Tax	MULTI	2019	(902,128)	0				(902,128)	0
50	City Tax	Local Tax	OH	2018	(37)	0	0	0	0	(37)	0
51	Local Tax	Local Tax	TX	2020	0	0				0	0
52	Local Tax	Local Tax	TX	2022	1,764,161	0		1,764,161		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)	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)
53	Local Tax	Local Tax	TX	2023			8,929,732	7,214,754		1,714,978	
54	**Subtotal Local Tax**				3,219,108	23,367	18,851,191	19,017,947	0	3,039,671	10,685
55	**Subtotal Other Tax**				0	0	0	0	0	0	0
56	Property Tax	Property Tax	AR	2022	18,141,210	0	(80,409)	18,060,801	0	0	0
57	Property Tax	Property Tax	AR	2023	0	0	18,244,999	293	0	18,244,706	0
58	Property Tax	Property Tax	CO	2020	0	0	0	0	0	0	0
59	Property Tax	Property Tax	CO	2021	0	0	0	0	0	0	0
60	Property Tax	Property Tax	LA	2017	0	0	0	0	0	0	0
61	Property Tax	Property Tax	LA	2022	542,215	0	568	542,783	0	0	0
62	Property Tax	Property Tax	LA	2023	0	0	44,158,744	44,158,744	0	0	0
63	Property Tax	Property Tax	MO	2022	790	0	(790)	0		0	0
64	Property Tax	Property Tax	MO	2023			28,641	28,641		0	
65	Property Tax	Property Tax	NE	2019	0	0				0	0
66					0	0	0	0	0	0	0
67	Property Tax	Property Tax	OK	2022	2,228,185	0	(14,885)	2,213,300	0	0	0
68	Property Tax	Property Tax	OK	2023			9,586,736	4,823,434		4,763,302	
69	Property Tax	Property Tax	TX	2022	21,193,562		(160)	21,193,401		1	
70	Property Tax	Property Tax	TX	2023			24,917,924	3,975,942	0	20,941,982	
71	Property Tax	Property Tax	WV	2022	0	0	168	168		0	0
72	Property Tax	Property Tax	WY	2021	297	0	(297)			0	0
73	Property Tax	Property Tax	WY	2022			3,048	3,048		0	
74	Property Tax	Property Tax	MS	2020			0	0		0	
75	Property Tax	Property Tax	AZ	2020	0	0	0	0		0	0
76	**Subtotal Property Tax**				42,106,258	0	96,844,288	95,000,555	0	43,949,991	0
77	UNEMPLOYMENT 2023	Unemployment Tax			4,466		74,939	62,998		16,407	
78	STATE UNEMPLOYMENT 2023	Unemployment Tax	AR		17,771		8,165	23,884		2,052	
79	STATE UNEMPLOYMENT 2023	Unemployment Tax	LA		605		4,200	3,959		845	
80	STATE UNEMPLOYMENT 2023	Unemployment Tax	NE								
81	STATE UNEMPLOYMENT 2023	Unemployment Tax	OK								
82	STATE UNEMPLOYMENT 2023	Unemployment Tax	TX		6,735		34,566	33,270		8,031	
83	**Subtotal Unemployment Tax**				29,577	0	121,870	124,111	0	27,336	0
84	Sales & Use Tax	Sales And Use Tax	AR	2019			(71,711)	(71,711)		0	0
85	Sales & Use Tax	Sales And Use Tax	AR	2022	1,992,915	915,800	(690,127)	386,988		0	
86	Sales & Use Tax	Sales And Use Tax	AR	2023			9,429,600	9,457,783		932,017	960,200
87	Sales & Use Tax	Sales And Use Tax	LA	2022	1,202,198	0	8,918	1,211,116	0	0	0
88	Sales & Use Tax	Sales And Use Tax	LA	2023			7,136,067	6,591,465		544,602	
89	Sales & Use Tax	Sales And Use Tax								0	0
90	Sales & Use Tax	Sales And Use Tax	OK	2022	9,286	3,586	(5,735)	1,029	0	0	1,064
91	Sales & Use Tax	Sales And Use Tax	OK	2023	0	0	89,377	88,246	0	9,614	8,483
92	Sales & Use Tax	Sales And Use Tax	TX	0	1,040,400		(1,040,400)	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 Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR	
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)
93	Sales & Use Tax	Sales And Use Tax	TX	2017	(361,124)	0	361,124			0	0
94	Sales & Use Tax	Sales And Use Tax	TX	2018	(459,443)	0	459,443			0	0
95	Sales & Use Tax	Sales And Use Tax	TX	2020	0	0	(4,010,699)	(4,010,699)		0	0
96	Sales & Use Tax	Sales And Use Tax	TX	2022	711,077	0	47,710	758,786		1	0
97	Sales & Use Tax	Sales And Use Tax	TX	2023			22,389,504	22,056,277		333,227	
98	**Subtotal Sales And Use Tax**				4,135,309	919,386	34,103,071	36,469,280	0	1,819,461	969,747
99	**Subtotal Income Tax**				0	0	0	0	0	0	0
100	Excise Tax	Excise Tax		2023	0	0	5,060	5,060	0	0	0
101	**Subtotal Excise Tax**				0	0	5,060	5,060	0	0	0
102	**Subtotal Fuel Tax**				0	0	0	0	0	0	0
103	FICA 2023	Federal Insurance Tax			1,202,515		11,664,367	12,233,841		633,040	
104	**Subtotal Federal Insurance Tax**				1,202,515	0	11,664,367	12,233,841	0	633,041	0
105	Franchise Tax	Franchise Tax	AR	2021	0	0	0			0	0
106	Franchise Tax	Franchise Tax	DE	2017	15,100	0	0	0	0	15,100	0
107	Franchise Tax	Franchise Tax	DE	2019	(17,565)	0	0	0	0	(17,565)	0
108	Franchise Tax	Franchise Tax	DE	2020	17,415	0	0	0	0	17,415	0
109	Franchise Tax	Franchise Tax	DE	2021	0	0	0	0	0	0	0
110	Franchise Tax	Franchise Tax	LA	2005	0	0	0	0	0	0	0
111	Franchise Tax	Franchise Tax	LA	2017	(378,956)	0	0	0	0	(378,956)	0
112	Franchise Tax	Franchise Tax	LA	2018	(1,176,415)	0	0	0	0	(1,176,415)	0
113	Franchise Tax	Franchise Tax	LA	2019	(3,469,591)	0		0	0	(3,469,591)	0
114	Franchise Tax	Franchise Tax	LA	2020	(309,946)	0	0		0	(309,946)	0
115	Franchise Tax	Franchise Tax	LA	2021	623,871	0		0	0	623,871	0
116	Franchise Tax	Franchise Tax	LA	2022	4,242,592		0	3,340,000		902,592	
117	Franchise Tax	Franchise Tax	LA	2023			4,922,787			4,922,787	
118	Franchise Tax	Franchise Tax	OH	2005	0	0				0	0
119	Franchise Tax	Franchise Tax	OK	2023	0	0	20,100	20,100		0	0
120	Franchise Tax	Franchise Tax	TX	2005	0	0				0	0
121	**Subtotal Franchise Tax**				(453,495)	0	4,942,887	3,360,100	0	1,129,292	0
122	Other State Tax	Other State Tax	OH	2022	0	0	2	2		0	0
123	Other State Tax	Other State Tax	OH	2023	0	0	7	7		0	0
124	**Subtotal Other State Tax**				0	0	9	9	0	0	0
125	Other Property Tax	Other Property Tax			0	0	0	0		0	
126	**Subtotal Other Property Tax**				0	0	0	0	0	0	0
127	PUC Fees	Other Use Tax	AR	2022	522,000	0	(522,000)			0	
128	Gross Receipts Tax	Other Use Tax	TX	2022	509,000		(509,000)				
129	Gross Receipts Tax	Other Use Tax	TX	2023	0	0	8,001,769	8,001,769		0	
130	**Subtotal Other Use Tax**				1,031,000	0	6,970,769	8,001,769	0	0	0
131	**Subtotal Other Advalorem Tax**				0	0	0	0	0	0	0
132	LA Occup Lic Fees	Other License And Fees Tax	LA	2023	0	0	91,625	91,625	0	0	0
133	State License Registration	Other License And Fees Tax	LA	2019	(12)		35	23		0	
134	State License Registration	Other License And Fees Tax	OK	2020	(10)	0	10			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 Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR	
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)
135	**Subtotal Other License And Fees Tax**				(22)	0	91,670	91,648	0	0	0
136	**Subtotal Payroll Tax**				0	0	0	0	0	0	0
137	Public Serv Comm	Ad Valorem Tax	LA	2021	(521,490)	0	149,966	(371,524)		0	
138	Public Serv Comm	Ad Valorem Tax	LA	2022	600,000	0		600,000		0	
139	**Subtotal Advalorem Tax**				78,510	0	149,966	228,476	0	0	0
140	**Subtotal Other Allocated Tax**				0	0	0	0	0	0	0
141	**Subtotal Severance Tax**				0	0	0	0	0	0	0
142	**Subtotal Penalty Tax**				0	0	0	0	0	0	0
143	Other Taxes & Fees	Other Taxes and Fees	AR	2021	0	0	0	0	0	0	
144	Other Taxes & Fees	Other Taxes and Fees	AR	2022		0	0		0	0	0
145	Other Taxes & Fees	Other Taxes and Fees	LA	2022	0	0	0		0	0	0
146	Other Taxes & Fees	Other Taxes and Fees	LA	2021	0	0		0	0	0	0
147	Other Taxes & Fees	Other Taxes and Fees	TX	2021	0	0	0	0		0	0
148	Other Taxes & Fees	Other Taxes and Fees	TX	2022		0	0	0		0	0
149	**Subtotal Other Taxes And Fees**				0	0	0	0	0	0	0
40	TOTAL				35,703,239	942,753	123,684,306	132,135,135	0	27,290,089	980,432

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	(75,819,535)		0	24,753,801
2	(75,819,535)	0	0	24,753,801
3	0		0	0
4	0		0	0
5	0		0	0
6	0		0	0
7	0		0	
8	1,562,475			
9	0			0
10	(55,322)			(709,907)
11	0		0	0
12	0		0	0
13	0		0	0
14	0		0	0
15	0		0	
16			0	0
17	0			0
18	1,447,349			(1,693,579)
19	0	0	0	
20	0	0	0	
21			0	0
22	0	0	0	0
23	0	0	0	0
24	0	0	0	0
25	0	0	0	
26			0	
27				
28				
29	(1)		0	0
30	0	0	0	0
31	0	0	0	0
32	0	0	0	0
33	0	0	0	
34			0	0
35	0			0
36	21,708			(25,144)
37	0	0	0	0
38	0	0	0	0
39	0	0	0	0
40	0	0	0	0
41	0	0	0	
42			0	
43				
44	280,870			176,443
45	3,257,079	0	0	(2,252,187)
46			0	
47			0	23,367
48	9,921,459			(23,367)
49				
50	0	0	0	0
51	0		0	0
52			0	0
53	8,929,732			

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	18,851,191	0	0	0
55	0	0	0	0
56	(87,774)		0	7,364
57	17,182,259		0	1,062,740
58			0	
59			0	0
60	125,516			(125,516)
61	568		0	0
62	43,125,311		0	1,033,433
63				(790)
64				28,641
65				
66	0	0	0	0
67	(32,450)		0	17,566
68	13,273,114			(3,686,378)
69	(218)			58
70	24,117,198			800,726
71	0	0	0	168
72	0	0	0	(297)
73				3,048
74				0
75	0	0	0	0
76	97,703,524	0	0	(859,236)
77	47,565			27,374
78	(13,320)			21,484
79	2,560			1,640
80				
81	1,706			(1,706)
82	20,314			14,253
83	58,825	0	0	63,045
84	(51,326)			(20,385)
85	(315)			(689,812)
86	(43,911)			9,473,511
87				8,918
88	637			7,135,430
89		0	0	
90	0		0	(5,735)
91	17,158		0	72,221
92	(440,000)			(600,400)
93	0	0	0	361,124
94	0	0	0	459,443
95	(881,292)	0	0	(3,129,407)
96	(200)		0	47,910
97	13,720			22,375,782
98	(1,385,529)	0	0	35,488,600
99	0	0	0	0
100	5,060		0	0
101	5,060	0	0	0
102	0	0	0	0
103	6,847,044			4,817,323
104	6,847,044	0	0	4,817,323
105	0		0	0
106	0		0	0

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	0		0	0
108			0	0
109	0		0	0
110	0	0	0	0
111	0	0	0	0
112	0	0	0	0
113	0	0	0	
114	0	0	0	
115			0	
116	0			
117	4,922,788			
118	0			
119	20,100			
120				
121	4,942,888	0	0	0
122	2	0	0	0
123	7	0	0	0
124	9	0	0	0
125	0			
126	0	0	0	0
127				(522,000)
128				(509,000)
129	8,001,769			
130	8,001,769	0	0	(1,031,000)
131	0	0	0	0
132	91,625		0	0
133	35		0	
134	10	0	0	0
135	91,670	0	0	0
136	0	0	0	0
137				149,966
138				
139	0	0	0	149,966
140	0	0	0	0
141	0	0	0	0
142	0	0	0	0
143			0	0
144	0		0	0
145	0		0	0
146	0		0	
147	0		0	0
148	0		0	0
149	0	0	0	0
40	62,553,995	0	0	61,130,312

Name of Respondent:	This report is:	Date of Report:	Year/Period of Report
SWEPCO	(1) ☑ An Original (2) ☐ A Resubmission	04/09/2024	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%				411.4					
3	4%				411.4					
4	7%				411.4					
5	10%	434,367	411.1		411.4	247,752		186,615	43 Years	
6	State DITC		411.1		411.4					
7	30%				411.4					
8	TOTAL Electric (Enter Total of lines 2 thru 7)	434,367				247,752		186,615		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL	434,367						186,614		

Name of Respondent: SWEPCO	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
1	Insurance Liability - BREMCO	(5,644)	
2	[(a)] Turk Power Plant Joint Ownership Deferred Credits	8,151,571	
3	[(b)] Current Portion of Turk Power Plant Joint Ownership Deferred Credits	54,920	
4	Pole Attachments	1,699,042	
5	Customer Advance Receipts	5,959,422	
6	Contribution in Aid of Construction	2,741,347	
7	Pirkey Land Lease Obligations		
8	Qaulity of Service/Notice of Violation Penalty	689,561	
9	F.J. Doyle Salvage - Federal Super Fund Site	350,000	
10	Dolet Hills Def Lignite Lease Obligation	11,053,425	
11	Provision for refund related to overcollection of 2022 SPP revenue	5,625,976	
12	Minor Items	5,136,971	
47	TOTAL	41,456,591	

Line No.	DEBITS
	Contra Account (c)
1	107/108/142/146/151/152/154/163/165/184/186/232/234/235/236/242/253/440/442/444/426/500/501/505/506/510/511/512/513/514/583/588/592/593/908/921/935
2	253/419
3	253
4	172/173/454/589
5	142
6	107/108
7	107/108/143/146/151/154/163/165/183/184/186/232/234/500/501/502/505/506/510/511/512/513/514/566/903/921/923/928/935/2360/253
8	242/426
9	
10	142/143/151/234/243/253
11	229/234/242/449
12	131/142/146/181/184/186/232/234/235/242/565
47	

Line No.	DEBITS		
	Amount (d)	Credits (e)	Balance at End of Year (f)
1	15,669	40,193	18,880
2	45,503	650,189	8,756,257
3	9,416		45,504
4	3,782,360	3,913,813	1,830,495
5	5,959,423	7,491,779	7,491,778
6	2,741,347	1,536,862	1,536,862
7	127,806	2,249,877	2,122,071
8	82,780		606,781
9			350,000
10	3,452,007	1,478,765	9,080,183
11	6,029,992	30,326,167	29,922,151
12	5,019,327	1,783,986	1,901,630
47	27,265,630	49,471,631	63,662,592

Name of Respondent: SWEPCO	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: DescriptionOfOtherDeferredCredits

Formula Rate Uses:
SPP Independent Power Producers System Upgrade Credits By Function
YEAR 2023

Description	Balance at Beg of Year	Transmission Debit	Transmission Credit	Generation Debit	Generation Credit	Balance at End of Year
GENERATION						
Generation IPP Prepayment	24,412,547				(170,633)	24,241,914
Joint Owner IPP Credits	(8,151,571)			45,503	(650,189)	(8,756,257)
Current Portion of Joint Owner Credits	(54,920)			9,417		(45,503)
SWEPCO Share Generation IPP Prepayment	16,206,056	—	—	54,919	(820,821)	15,440,154
Transmission IPP Credits	(24,412,547)	—	170,633			(24,241,914)
TOTAL SWEPCo Company						
Total Line 3 & Line 6	(8,206,491)	—	170,633	54,919	(650,189)	(8,631,128)

(b) Concept: DescriptionOfOtherDeferredCredits

See Line 3 Footnote.

Name of Respondent: SWEPCO	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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities	74,315,964	2,424,514	5,024,027							71,716,451
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	74,315,964	2,424,514	5,024,027							71,716,451
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)](25,411,805)					254	16,339	254	415,074	(25,013,070)
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	48,904,159	2,424,514	5,024,027				16,339		415,074	46,703,381
18	Classification of TOTAL										
19	Federal Income Tax	48,904,159	2,424,514	5,024,026				16,339		415,074	46,703,381
20	State Income Tax										
21	Local Income Tax										

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Name of Respondent: SWEPCO	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

Formula Rate uses 13 month average.

Description Page 272-273 Line 16	Balance at Beginning of The year	Balance End of Year
SFAS 109	(25,411,805)	(25,013,070)
Total Line 16	(25,411,805)	(25,013,070)

Name of Respondent: SWEPCO	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.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	1,432,685,215	145,262,395	105,128,174					190		1,472,819,436
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	1,432,685,215	145,262,395	105,128,174							1,472,819,436
6	Other	[(a)](383,229,530)					1823/254	3,726,833	1823/254	16,417,014	(370,539,349)
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,049,455,685	145,262,395	105,128,174				3,726,833		16,417,014	1,102,280,087
10	Classification of TOTAL										
11	Federal Income Tax	1,049,455,685	145,262,394	105,128,174				3,726,833		16,417,015	1,102,280,087
12	State Income Tax										
13	Local Income Tax										

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Name of Respondent: SWEPCO	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: AccumulatedDeferredIncomeTaxesOtherProperty

Formula Rate uses 13 month average.

Line 6 Footnote

	Beg Bal	End Bal
Non-Utility	—	—
SFAS 109	(383,229,530)	(370,539,349)
Total Other - Line 6	(383,229,530)	(370,539,349)

Name of Respondent: SWEPCO	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 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 283										
2	Electric										
3	DEFD STORM DAMAGE	31,808,270	482,497	723,000							31,567,767
4	REG ASSET-SFAS 158 - PENSIONS	14,649,368	4,061,532								18,710,900
5	REG ASSET-SWEPCo TX Fuel Mine Costs		16,978,691								16,978,691
6	ACCRD SFAS 106 PST RETIRE EXP	15,088,127	1,470,068	22,913							16,535,282
7	REG ASSET-Pirkey LA Share Undeprec Bal		14,151,021	331,391							13,819,630
8	Other	22,479,972	57,141,897	32,978,865					283		46,643,004
9	TOTAL Electric (Total of lines 3 thru 8)	84,025,737	94,285,706	34,056,169							144,255,274
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	[(a)]264,648,642					1823/254	89,744,710	1823/254	126,459,602	301,363,534
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	[(b)]348,674,379	94,285,706	34,056,169				89,744,710		126,459,602	445,618,808
20	Classification of TOTAL										
21	Federal Income Tax	139,964,276	94,285,706	34,056,169				16,349,400		31,303,284	215,147,697
22	State Income Tax	208,710,103						73,395,310		95,156,318	230,471,111
23	Local Income Tax										

NOTES

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Line 18 Other - Detail	Balance at Beginning of Year	Balance at End of Year
SFAS 109	264,299,907	291,161,669
Hedge - Cash Flow	348,735	398,543
Provision Optimization	—	9,803,322
Total	$ 264,648,642	$ 301,363,534

(b) Concept: AccumulatedDeferredIncomeTaxesOther

Formula Rate uses 13 month average.

Name of Respondent: SWEPCO	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		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Arkansas Southwest Power Pool Transmission Cost Rider Over Recovery	2,562,502	254, 565	2,594,403	3,115,730	3,083,829
2	Deferred Overrecovery Fuel Costs - Louisiana	1,426,300	182, 557	1,426,300	3,260,055	3,260,055
3	Louisiana EAC Over/Under Recovery and Interest				138,906	138,906
4	Earnings Subject to Refund under State of Texas Restructuring Legislation - Public Utility Commission of Texas, PUCT Dockets No. 29938, 22276, and 37364, Amortization of 44 years beginning in May 2010	2,255,476	407	72,000		2,183,476
5	FAS 109 Deferred Federal Income Tax	601,773,550	182, 190, 236, 254, 255, 282, 283, 409, 410, 411, 281	21,362,474	4,850,378	585,261,454
6	Overrecovery of Energy Efficiency Program Expense Louisiana	3,575,173	182, 908	3,490,481	5,157,999	5,242,691
7	Unrealized Gain/Loss on Forward Commitments	1,072,723	182	1,403,203	330,480	
8	Vegetation Management - Texas PUCT, Docket No.40443		593	2,353,977	2,969,105	615,128
9	Advanced Metering System (AMS) deployment plan for SWEPCO LA in Docket No. U36169.		182, 254, 403	4,602	2,119,815	2,115,213
10	NOLC regulatory asset and regulatory liability consistent with the Order issued in U-35441 addressing the NOLC treatment per Regulatory Accounting.				15,543,152	15,543,152
41	TOTAL	612,665,725		32,707,441	37,485,620	617,443,904

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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	750,738,125	852,716,194	6,137,956	6,538,269	469,470	467,453
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	561,973,101	643,596,906	5,538,280	5,731,850	75,290	74,778
5	Large (or Ind.) (See Instr. 4)	361,585,769	437,560,153	5,147,435	5,174,144	6,723	6,824
6	(444) Public Street and Highway Lighting	9,646,884	10,505,487	70,983	74,572	576	596
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	1,683,943,879	1,944,378,740	16,894,653	17,518,835	552,060	549,651
11	(447) Sales for Resale	190,968,179	318,982,799	5,867,390	6,951,551		
12	TOTAL Sales of Electricity	1,874,912,058	2,263,361,540	22,762,043	24,470,386	552,060	549,651
13	(Less) (449.1) Provision for Rate Refunds	55,838,133	11,905,582				
14	TOTAL Revenues Before Prov. for Refunds	1,819,073,924	2,251,455,958	22,762,043	24,470,386	552,060	549,651
15	Other Operating Revenues						
16	(450) Forfeited Discounts	5,251,770	5,322,335				
17	(451) Miscellaneous Service Revenues	1,440,961	1,055,598				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	10,019,634	9,337,226				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	13,599,410	9,670,136				
22	(456.1) Revenues from Transmission of Electricity of Others	185,447,953	158,248,618				
23	(457.1) Regional Control Service Revenues	145,200					
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	215,904,928	183,633,914				
27	TOTAL Electric Operating Revenues	2,034,978,853	2,435,089,872				

Line12, column (b) includes $ (6,013,818) of unbilled revenues.
Line12, column (d) includes (154,800) MWH relating to unbilled revenues

Name of Respondent: SWEPCO	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					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
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37					
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39					
40					
41					
42					
43					
44					
45					
46	TOTAL				145,200

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Name of Respondent: SWEPCO	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	[(a)] Residential Service RS ARK	1,013,147	132,223,952	97,759	10,364	0.1305
2	Residential-Electric heating appliance ARK	127,423	15,645,850	9,100	14,003	0.1228
3	Master Metered Apartments ARK	962	100,138	8	120,250	0.1041
4	Lighting PL/AL/OL ARK	4,276	832,706	7,027	609	0.1947
5	Residential Service RS LA	2,872,483	360,226,763	207,176	13,865	0.1254
6	Residential Service RWH LA	1,214	144,848	77	15,766	0.1193
7	Master Metered Apartments LA	19,993	2,011,881	28	714,036	0.1006
8	Lighting PL/AL/OL	16,220	5,799,955	29,103	557	0.3576
9	Residential Service RS TX	2,137,904	286,794,193	155,297	13,767	0.1341
10	Deferred Fuel		(53,091,114)			
11	Duplicate Customers			(54,952)		
12	Master Metered Apartments TX	10,535	1,018,531	25	421,400	0.0967
13	Lighting PL/AL TX	12,547	2,422,150	18,822	667	0.1930
41	TOTAL Billed Residential Sales	6,216,704	754,129,853	469,470	13,242	0.1213
42	TOTAL Unbilled Rev. (See Instr. 6)	(78,748)	(3,391,728)			
43	TOTAL	6,137,956	750,738,125	469,470	13,074	0.1223

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Name of Respondent: SWEPCO	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: DescriptionOfNumberAndTitleOfRateSchedule

The estimated additional revenue billed pursuant to the fuel adjustment clause is as follows:

	Arkansas	Louisiana	Texas
Residential	52,404,966.39	145,093,046.34	75,838,344.78
Commercial	57,124,555.09	107,917,784.77	68,676,883.11
Industrial	49,157,575.27	54,654,895.41	85,377,488.28
Public Street & Highway Lighting	423,836.85	1,818,839.44	874,516.03

Name of Respondent: SWEPCO	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	General Service GS	353,674	41,870,032	16,440	21,513	0.1184
2	Recreational Lighting ARK	3,939	369,724	94	41,904	0.0939
3	Lighting & Power Service LP LA	1,613,671	158,108,599	2,362	683,180	0.0980
4	Irrigation SVC LA					
5	Municipal Pumping MPS LA	80,201	7,001,930	605	132,564	0.0873
6	Municipal Service MS LA	20,075	2,969,787	1,032	19,453	0.1479
7	Lighting PL/AL/OL LA	19,113	4,650,075	12,101	1,579	0.2433
8	Lighting & Power Service LP ARK	810,720	81,048,626	1,422	570,127	0.1000
9	Large Lighting and Power Service LLP ARK	73,965	6,604,930	1	73,965,000	0.0893
10	Municipal Pumping Service MPS ARK	11,329	1,224,280	262	43,240	0.1081
11	Municipal Service MS ARK	4,820	581,337	450	10,711	0.1206
12	Lighting PL/AL/OL ARK	14,353	2,125,059	8,972	1,600	0.1481
13	Electric Sign Service ESS LA	548	91,344	311	1,762	0.1667
14	General Service GS LA	284,281	45,845,296	16,623	17,102	0.1613
15	General Lighting & Power GLP LA	197,372	26,324,709	4,407	44,786	0.1334
16	General Service GS TX	284,585	42,363,673	21,286	13,370	0.1489
17	Recreational Lighting Comm TX	6,151	675,803	156	39,429	0.1099
18	Lighting PL/AL TX	27,700	4,318,779	15,897	1,742	0.1559
19	Cotton Gin CG TX	3,760	445,046	7	537,143	0.1184
20	Lighting & Power Service LP TX	1,635,630	174,383,977	7,585	215,640	0.1066
21	Lighting & Power Service LLP TX	55,123	4,081,217	1	55,123,000	0.0740
22	Municipal Pumping MPS TX	62,558	5,552,573	607	103,061	0.0888
23	Municipal Service MS TX	26,075	2,827,888	1,568	16,629	0.1085
24	Deferred Fuel		(49,676,322)			
25	Duplicate Customers			(36,970)		
26	Lighting CSL TX	1,077	128,155	71	15,169	0.1190
41	TOTAL Billed Small or Commercial	5,590,720	563,916,517	75,290	74,256	0.1009
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	(52,440)	(1,943,417)			
43	TOTAL Small or Commercial	5,538,280	561,973,101	75,290	73,559	0.1015

Name of Respondent: SWEPCO	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)
1	General Service GS Ark	10,917	1,320,427	340	32,109	0.1210
2	Lighting & Power Service LP Ark	760,516	70,067,807	260	2,925,062	0.0921
3	Large Lighting & Power LLP Ark	166,530	10,791,366	1	166,530,000	0.0648
4	Pulp & Paper Mill P&PM Ark	209,207	12,803,015	1	209,207,000	0.0612
5	Lighting PL/AL/OL Ark	2,043	267,709	824	2,479	0.1310
6	General Power Service GPS LA	10,978	1,942,247	980	11,202	0.1769
7	General Lighting & Power GLP LA	34,744	4,509,381	675	51,473	0.1298
8	Lighting & Power Service LP LA	859,854	71,615,533	351	2,449,726	0.0833
9	Large Lighting & Power LLP LA	252,585	18,683,840	2	126,292,500	0.0740
10	Lighting PL/AL/OL	1,206	279,761	612	1,971	0.2320
11	General Service GS TX	12,949	2,028,766	1,403	9,230	0.1567
12	Lighting & Power Service LP TX	1,071,754	106,437,661	1,235	867,817	0.0993
13	Duplicate Customers			(2,674)		
14	Interruptible Power Service TX	46,664	3,086,286	3	15,554,667	0.0661
15	Large Lighting & Power Service LLP TX	1,123,547	65,915,666	5	224,709,400	0.0587
16	Large Lighting & Power Service LLP w/Bkup,Maint,AAS TX	163,120	12,483,255	2	81,560,000	0.0765
17	Metal Melting Service MMS TX	38,929	3,631,174	9	4,325,444	0.0933
18	Metal Melting Svc MMS Transmission TX	18,344	1,462,346	1	18,344,000	0.0797
19	Oilfield-Large Industrial OLI TX	377,129	29,099,426	1,455	259,195	0.0772
20	Lighting PL/AL TX	3,132	469,742	1,238	2,530	0.1500
21	Deferred Fuel		(54,663,543)			
41	TOTAL Billed Large (or Ind.) Sales	5,164,148	362,231,865	6,723	768,131	0.0701
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(16,713)	(646,096)			
43	TOTAL Large (or Ind.)	5,147,435	361,585,769	6,723	765,646	0.0702

Name of Respondent: SWEPCO	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	Municipal Lighting ML ARK	8,553	1,912,781	211	40,536	0.2236
2	Municipal Lighting ML LA	36,731	4,335,535	177	207,520	0.1180
3	Deferred Fuel		(523,284)			
4	Municipal Lighting ML TX	26,346	3,954,430	188	140,138	0.1501
41	TOTAL Billed Public Street and Highway Lighting	71,630	9,679,462	576	124,358	0.1351
42	TOTAL Unbilled Rev. (See Instr. 6)	(647)	(32,578)			
43	TOTAL	70,983	9,646,884	576	123,234	0.1359

Name of Respondent: SWEPCO	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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3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
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41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		55,838,133			

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

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	17,043,202	1,689,957,697	552,059	979,987	
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(148,548)	(6,013,819)			
43	TOTAL - All Accounts	16,894,654	1,683,943,878	552,059	979,987	

Name of Respondent: SWEPCO	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	Requirements Service (RQ)										
2	[(a)] City of Bentonville, Arkansas (1)	RQ	126	141.5	125.1	122.7	703,418	18,929,730	25,519,231		44,448,961
3	City of Hope, Arkansas (1)	RQ	125	51.0	38.4	36.9	229,678	6,642,564	8,413,549		15,056,113
4	City of Minden, Louisiana (1)	RQ	128	31.9	27.7	26.6	134,572	4,175,526	4,593,000		8,768,526
5	City of Prescott, Arkansas (1)	RQ	127	13.4	12.8	10.1	68,173	1,723,085	2,260,313		3,983,398
6	Northeast Texas Electric	RQ	113	0.0	0.0	0.0	0				
7	Cooperative, Inc (NTEC) (1)		119	120.0	0.0	0.0	0	15,677,579	19,650,962		35,328,541
8	ETEC/ NTEC (1)	RQ	129	131.7	204.7	198.9	3,462,031	11,532,756	21,805,263		33,338,019
9	Rayburn Country Electric Coop, Inc(1,2)	RQ	111								
10	Tex-La Electric Reliability Council of Texas (ERCOT)	RQ	110								
11	Tex-La of Texas Elec. Coop. of Texas, Inc	RQ	120								
12	Corporation (AEPSC) (3)	OS	228								
13	AEPSC (3,8)	OS	228								
14	AEPSC (3,4)	OS	228							(222,646)	(222,646)
15	Electric Reliability Council of Texas										
16	(ERCOT) (6,8)	OS	NA								

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
17	Oklahoma Gas & Electric	OS	NA								
18	Southwest Power Pool (SPP) (7)	OS	NA				845,070		26,243,384	9,240,214	35,483,598
19	SPP Merchant Sales (5)	SF	NA				424,448		14,783,669		14,783,669
15	Subtotal - RQ						4,597,872	43,003,661	62,591,356		105,595,017
16	Subtotal-Non-RQ						1,269,518	15,677,579	60,678,015	9,017,568	85,373,162
17	Total						5,867,390	58,681,240	123,269,371	9,017,568	190,968,179
Page 310-311											

Name of Respondent: SWEPCO	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

Includes customer charge

(2) Wholesale transmission

(3) Respondent is an affiliated company of American Electric Power Service Corporation

(4) Bookout margins, net

(5) Merchant sale

(6) Net trading purchases & sales within the Electric Reliability Council of Texas (ERCOT)

(7) Net trading purchases & sales within the Southwest Power Pool (SPP)

(8) Realization System Integration Agreement Sharing

Name of Respondent: SWEPCO	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	16,770,733	20,700,248
5	(501) Fuel	382,292,673	617,230,019
6	(502) Steam Expenses	20,989,507	22,553,517
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	9,973,816	9,350,725
10	(506) Miscellaneous Steam Power Expenses	10,551,927	15,658,489
11	(507) Rents	503	
12	(509) Allowances	916,642	4,478,442
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	441,495,801	689,971,440
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,287,601	3,871,364
16	(511) Maintenance of Structures	5,554,603	5,587,787
17	(512) Maintenance of Boiler Plant	27,944,948	25,549,381
18	(513) Maintenance of Electric Plant	15,303,795	7,341,705
19	(514) Maintenance of Miscellaneous Steam Plant	5,727,915	6,715,651
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	56,818,862	49,065,888
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	498,314,662	739,037,328
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	(5,675)	

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	(5,675)	
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	(5,675)	
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,199,937	1,683,158
63	(547) Fuel	9,416,233	21,068,588
64	(548) Generation Expenses	258,761	260,749
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	1,083,229	953,766
66	(550) Rents	5,640,579	4,823,059
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	17,598,739	28,789,320
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	80,724	107,244
71	(553) Maintenance of Generating and Electric Plant	9,096,447	7,654,205
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	49,727	138,440
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	9,226,899	7,899,889
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	26,825,638	36,689,209
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	221,555,627	353,323,157
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	1,185,783	1,249,092
78	(557) Other Expenses	49,313,894	49,202,352
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	272,055,304	403,774,601
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	797,189,930	1,179,501,138
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	12,092,288	12,848,170
85	(561.1) Load Dispatch-Reliability		125
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	712,609	607,956
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,516	369
88	(561.4) Scheduling, System Control and Dispatch Services	5,795,334	5,137,717
89	(561.5) Reliability, Planning and Standards Development	228,411	231,133
90	(561.6) Transmission Service Studies	(13)	
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	1,147,621	946,226
93	(562) Station Expenses	1,042,278	1,071,674
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	65,311	141,589
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	102,223,406	126,984,644
97	(566) Miscellaneous Transmission Expenses	2,610,810	2,843,585
98	(567) Rents	37,062	55,551
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	125,956,632	150,868,739
100	Maintenance		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
101	(568) Maintenance Supervision and Engineering	16,232	5,292
102	(569) Maintenance of Structures	53,640	56,867
103	(569.1) Maintenance of Computer Hardware	8,084	8,487
104	(569.2) Maintenance of Computer Software	833,143	637,697
105	(569.3) Maintenance of Communication Equipment	76,207	97,270
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,408,309	3,228,207
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	21,863,711	15,771,832
109	(572) Maintenance of Underground Lines	157	349
110	(573) Maintenance of Miscellaneous Transmission Plant	1,850	2,238
111	TOTAL Maintenance (Total of Lines 101 thru 110)	25,261,334	19,808,239
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	151,217,966	170,676,978
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	1,927,022	1,799,650
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,927,022	1,799,650
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	1,927,022	1,799,650
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,951,988	2,669,139
135	(581) Load Dispatching	89,709	65,381
136	(582) Station Expenses	1,237,425	1,422,024
137	(583) Overhead Line Expenses	1,313,333	705,194
138	(584) Underground Line Expenses	2,159,193	1,941,154
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	30,220	245,356
140	(586) Meter Expenses	3,528,872	4,135,070
141	(587) Customer Installations Expenses	780,877	484,464
142	(588) Miscellaneous Expenses	19,599,925	20,264,368
143	(589) Rents	1,029,116	913,687
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	31,720,658	32,845,837
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	134,960	108,073
147	(591) Maintenance of Structures	15,279	54,172
148	(592) Maintenance of Station Equipment	1,919,357	1,354,609
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	58,187,799	61,354,854
150	(594) Maintenance of Underground Lines	718,317	710,492
151	(595) Maintenance of Line Transformers	151,917	133,220
152	(596) Maintenance of Street Lighting and Signal Systems	86,150	110,145

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
153	(597) Maintenance of Meters	358,201	440,759
154	(598) Maintenance of Miscellaneous Distribution Plant	158,076	306,759
155	TOTAL Maintenance (Total of Lines 146 thru 154)	61,730,056	64,573,083
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	93,450,714	97,418,920
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	344,198	667,424
160	(902) Meter Reading Expenses	2,576,082	2,502,598
161	(903) Customer Records and Collection Expenses	17,802,775	17,364,270
162	(904) Uncollectible Accounts	(6,220)	591,316
163	(905) Miscellaneous Customer Accounts Expenses	83,774	64,586
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	20,800,610	21,190,194
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	10,024,487	10,686,247
168	(908) Customer Assistance Expenses	14,834,769	13,083,971
169	(909) Informational and Instructional Expenses	1	252
170	(910) Miscellaneous Customer Service and Informational Expenses	16,993	39,889
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	24,876,251	23,810,359
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	109,706	185,684
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	109,706	185,684
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	35,068,331	35,195,053
182	(921) Office Supplies and Expenses	3,169,865	2,352,276
183	(Less) (922) Administrative Expenses Transferred-Credit	7,175,093	4,535,722
184	(923) Outside Services Employed	4,004,437	10,615,639
185	(924) Property Insurance	7,653,598	3,852,216
186	(925) Injuries and Damages	4,423,839	4,313,559
187	(926) Employee Pensions and Benefits	1,774,157	5,506,516
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	8,165,441	10,323,175
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	411,315	130,664
192	(930.2) Miscellaneous General Expenses	1,818,497	1,908,731
193	(931) Rents	702,944	830,618
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	60,017,330	70,492,725
195	Maintenance		
196	(935) Maintenance of General Plant	6,644,237	7,435,532
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	66,661,567	77,928,257
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,156,233,765	1,572,511,180

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Name of Respondent: SWEPCO	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	[(a)] Cajun Electric Cooperative, Inc. (1)	OS	NA							
2	Exelon Green Country	OS	NA							
3	CALP	OS	NA							
4	INVE2	OS	NA							
5	KIOWA	OS	NA							
6	Canadian Wind (3)	OS	NA				472,966			
7	ERCOT (5)	OS	NA							
8	Flat Ridge Wind Farm (3)	OS	NA				305,256			
9	Majestic Wind Farm (3)	OS	NA				634,086			
10	Southwest Power Pool (4)	OS	NA				6,757,219			
11	Snider Industries (2)	OS	NA				9,519			
12	VAISALA MONTHLY FORECASTING F	OS	NA							
13	North Central Wind Facility	OS	NA							
14	VAISALA - MAVERICK - 54.5 SWE	OS	NA							
15	VAISALA - SUNDANCE - 54.5 SWE	OS	NA							
15	TOTAL						8,179,046	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	4,200,000			4,200,000
2	1,541,243			1,541,243
3	(555,015)			(555,015)
4	1,762,463			1,762,463
5	1,215,008			1,215,008
6		14,065,966		14,065,966
7				
8		9,654,614		9,654,614
9		27,153,633		27,153,633
10		136,409,750	25,773,784	162,183,534
11		317,373		317,373
12		5,603		5,603
13				
14		5,603		5,603
15		5,603		5,603
15	8,163,699	187,618,145	25,773,784	221,555,628

Name of Respondent: SWEPCO	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
C apacity (3) Cogeneration (4) Wind Energy (5) Net Trading Purchases & Sales within Southwest Power Pool (SPP) (6) Net Trading Purchases & Sales within ERCOT

Name of Respondent: SWEPCO	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)	Megawatt Hours Delivered (j)
1	American Electric Power Service	Various	Various	OS	N/A	Various	Various			
2	[(a)] Corporation (1, 2, 3)									
3	Corporation (1, 2, 3, 6)									
4	Snider Industries Inc (5)	Various	Various	OS	N/A	Various	Various			
5	Southwest Power Pool (2, 3, 6, 7)	Various	Various	OS	196	Various	Various			
6	Southwest Power Pool (2, 3, 7)	Various	Various	OS	196	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				
2			53,783,929	53,783,929
3			(3,814,648)	(3,814,648)
4			840	840
5			20,987,989	20,987,989
6			114,489,843	114,489,843
35				

Name of Respondent: SWEPCO	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: PaymentByCompanyOrPublicAuthority

Respondent is an affiliated company of American Electric Power Service Corporation

(2) Facility charge

(3) Southwest Power Pool base plan funding

(4) Southwest Power Pool ancillary service schedule 1

(5) Network Integrated Transmission Service (NITS)

(6) Prior Year

(7) Transmission service charge

Name of Respondent: SWEPCO	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					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					

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

Name of Respondent: SWEPCO	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	American Electric Power Service Corporation (AEPSC) (1, 2, 3, 4, 5)	OS					57,360,726	57,360,726
2	Southwest Power Pool (3, 7)	OS					44,862,680	44,862,680
	TOTAL						102,223,406	102,223,406

Name of Respondent: SWEPCO	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	378,988
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	113,607
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Associated Business Development	568,883
7	AEP Service Corporation and Other Affiliated	
8	Companies Billed to or from Respondent	708,106
9	Chamber of Commerce	34,289
10	Miscellaneous Minor items less than $5,000	14,624
46	TOTAL	1,818,497

Name of Respondent: SWEPCO	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			32,294,926		32,294,926
2	Steam Production Plant	118,678,515	1,598,603			120,277,118
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	25,022,209	530,199			25,552,408
7	Transmission Plant	58,134,157				58,134,157
8	Distribution Plant	83,784,938				83,784,938
9	Regional Transmission and Market Operation					
10	General Plant	8,141,720	33,957			8,175,677
11	Common Plant-Electric					
12	TOTAL	293,761,539	2,162,759	32,294,926		328,219,224

B. Basis for Amortization Charges

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

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM -- COAL/LIGNITE						
13	311 - Flint Creek	44,497	50 years	9%	3.59%		
14	311- Turk	302,455	50 years	2%	2.16%		
15	311 - Welsh	73,465	50 years	9%	3.47%		
16	312 - Flint Creek	300,620	50 years	9%	5.28%		
17	312 - Turk	992,682	55 years	2%	2.14%		
18	312 - Welsh	587,359	50 years	9%	4.36%		
19	314 - Flint Creek	17,947	50 years	9%	4.02%		
20	314 - Turk	239,616	50 years	2%	2.13%		
21	314 - Welsh	144,456	50 years	9%	3.84%		
22	315 - Flint Creek	11,891	50 years	9%	4.08%		
23	315 - Turk	90,868	55 years	2%	2.13%		
24	315 - Welsh	48,234	50 years	9%	4.7%		
25	316 - Flint Creek	7,367	50 years	9%	3.96%		
26	316 - Turk	48,721	55 years	2%	2.19%		
27	316 - Welsh	22,607	50 years	9%	3.85%		
28	TOTAL COAL/LIGNITE	2,932,785					
29	STEAM -- GAS/OIL						
30	311.3-ArsenalHillStall	54,110	35 years	6%	3.05%		
31	311.3-Arsenal Hill	7,321	65 years	31%	4.28%		
32	311.3 - Knox Lee	10,104	65 years	63%	3.79%		
33	311.3 - Lieberman	5,797	65 years	35%	7%		
34	311.3 - Wilkes	9,064	65 years	31%	3.19%		
35	312.3-ArsenalHillStall	88,025	35 years	6%	3.25%		
36	312.3 - Arsenal Hill	8,047	65 years	31%	4.47%		
37	312.3 - Knox Lee	31,883	65 years	63%	4.15%		
38	312.3 - Lieberman	19,781	65 years	35%	6.13%		
39	312.3 - Wilkes	58,071	65 years	31%	4.24%		
40	314.3-ArsenalHillStall	172,983	35 years	6%	3.69%		
41	314.3 - ArsenalHill	5,311	65 years	31%	4.18%		
42	314.3 - Knox Lee	15,715	65 years	63%	4.05%		
43	314.3 - Lieberman	10,800	65 years	35%	5.08%		
44	314.3 - Wilkes	41,988	65 years	31%	3.65%		
45	315.3-ArsenalHillStall	39,805	35 years	6%	3.03%		
46	315.3 - Arsenal Hill	1,281	65 years	31%	5.59%		
47	315.3 - Knox Lee	4,910	65 years	63%	4.59%		
48	315.3 - Lieberman	3,494	65 years	35%	7.22%		
49	315.3 - Wilkes	15,131	65 years	31%	4.83%		
50	316.3-ArsenalHillStall	84,025	35 years	6%	3.05%		
51	316.3 - Arsenal Hill	7,833	65 years	31%	7.45%		
52	316.3 - Knox Lee	2,242	65 years	63%	4.86%		
53	316.3 - Lieberman	2,320	65 years	35%	9.2%		
54	316.3 - Wilkes	10,024	65 years	31%	5.46%		
55	TOTAL GAS/OIL	710,065					
56	OTHER GENERATION						
57	341 - Mattison	31,438	45 years	7%	2.58%		
58	341 - Maverick	242	0 years		3.34%		
59	344 - Mattison	84,608	45 years	7%	2.56%		
60	344 - Maverick	218,073	30 years		3.34%		
61	344 - Sundance	156,793	30 years		3.36%		
62	344 - Traverse	685,523	30 years		3.37%		
63	345 - Mattison	11,021	45 years	7%	2.84%		
64	346 - Mattison	1,882	45 years	7%	2.89%		

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	346 - Maverick	63	0 years		3.34%		
66	346 - Sundance	258	0 years		3.36%		
67	346 - Traverse	58	0 years		3.37%		
68	TOTAL OTHER	1,189,959					
69	TRANSMISSION						
70	350 (Rights)	109,984	70 years		1.36%	R5	
71	352	69,309	70 years	7%	1.44%	R3.5	
72	353	860,542	68 years	9%	1.51%	S0	
73	353.16	24,357	68 years	9%	1.52%	S0	
74	354	36,238	65 years	18%	1.33%	L3	
75	355	959,318	46 years	64%	3.33%	S0.5	
76	356	444,401	70 years	53%	2.09%	R2	
77	356.16	57,169	70 years	53%	2.01%	R2	
78	357	12,832	50 years		2%	R1.5	
79	358.16	863	50 years		1.99%	R1.5	
80	359	132	65 years		1.07%	R4	
81	TOTAL TRANSMISSION	2,575,145					
82	DISTRIBUTION						
83	360 (Rights)	3,624	60 years		1.44%	R4	
84	361	14,517	75 years	11%	1.43%	R3	
85	362	420,637	57 years	16%	1.95%	S0.5	
86	362.16	6,686	57 years	16%	1.89%	S0.5	
87	364	582,637	55 years	64%	2.82%	S0.5	
88	365	572,899	44 years	40%	3.07%	R1	
89	366	90,768	70 years		1.35%	R4	
90	367	280,850	46 years	17%	2.41%	R3	
91	368	496,802	44 years	10%	2.42%	L0	
92	369	117,096	59 years	74%	2.81%	R3	
93	370	67,426	15 years	26%	8.06%	L0	
94	370.16 - TX AMI	28,364	15 years	26%	14.29%	L0	
95	370.16 AR EurekaSpringsAMI	1,102	15 years	26%	8.06%	L0	
96	370.16 - LA AMI	16	15 years	26%	8.06%	L0	
97	370.16 - LA AMI Initial	15,392	7 years	26%	14.29%	L0	
98	370.16 Shreveport LA AMI	553	7 years	26%	14.29%	L0	
99	370.16 Valley LA AMI	3	7 years	26%	14.29%	L0	
100	371	51,561	25 years	31%	4.9%	L0	
101	373	55,162	40 years	34%	3.13%	L0	
102	TOTAL DISTRIBUTION	2,806,095					
103	GENERAL PLANT						
104	390	118,003	58 years	5%	1.55%	L0	
105	391	6,909	30 years		2.84%	SQ	
106	391 Computer	18	7 years		12.92%	SQ	
107	391 Wind	15	30 years		2.94%	SQ	
108	392	3,875	20 years	(3)%	2.45%	SQ	
109	393	3,551	30 years	2%	2.38%	SQ	
110	394	34,456	35 years	1%	2.24%	SQ	
111	394 - Wind	7	0 years		3.36%	SQ	
112	395	5,118	35 years	2%	1.8%	SQ	
113	396	740	20 years	(2)%	5.1%	SQ	
114	397	94,313	20 years		3.99%	SQ	
115	397.16	3,938	20 years		3.99%	SQ	
116	397.16 AMI	3,920	7 years		14.29%	SQ	
117	398	3,974	20 years		3.56%	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)
118	TOTAL GENERAL PLANT	278,837					
119	DEPRECIABLE SUM	[a]10,492,886					

Name of Respondent: SWEPCO	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: SWEPCO	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.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	EXPENSES INCURRED DURING YEAR CURRENTLY CHARGED TO Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)
1	Federal Energy Regulatory Commission Annual Assessment	1		1		Electic	928		
2	Rate Case Expenses Approved for Recovery in Final Orders:		1,804,232	1,804,232	909,981	Electic	928		
3	Expenses incrred related to SWEPCO's 2017 Fuel Reconciliation Filing - PUCT Docket 47553		(129,346)	(129,346)		Electic	928	(129,346)	
4	Expenses incrred related to Louisiana Public Service Commission Audit of SWEPCO		22,711	22,711		Electic	928	22,711	
5	Expense incured relate to managin Formula Rates for AEP's WEST Operating Companies and Transco's		193,847	193,847		Electic	928	193,847	
6	Other Miscellaneous expense related to Regulatory and Legislative Actions in the State of Louisiana		17,709	17,709		Electic	928	17,709	
7	Expense incuured relate to 2018 Louisiana IRP Filing					Electic	928		
8	Expense incurred relate to Texas Tax Filing					Electic	928		
9	Expense incured relate to Distribution Cost Recovery Factor Filing		9,702	9,702		Electric	928	9,702	
10	Expenses incrred relate to Transmission Cost Recovery Factor Filings and other Regulatory/Legislative Activies relating to Transmission		51,316	51,316		Electric	928	51,316	
11	Expense incurred relate to SWEPCO's 2019 Arkansas Base Rate Case					Electric	928		
12	Expenses incurred relate to SWEPCO's 2016 Texas Base Rate Case					Electric	928		
13	Miscellaneous Minor Items		239,744	239,744		Electric	928	239,744	
14	Expenses incurred relate to SWEPCO's 2020 Texas Base Rate Case					Electric	928		
15	2020 SWEPCO Texas Fuel Reconciliation		5,892	5,892		Electric	928	5,892	
16	Expense incurred relate to SWEPCO's 2020 Arkansas Base Rate Case		7,192	7,192		Electric	928	7,192	
17				0					
18	2019 SWEPCO LA Base Case Filng		8,732	8,732		Electric	928	8,732	
19	2020 Generation Cost Recovery Factor (GCRF) filing					Electric	928		
20	Hurricane Laura Storm Recovery		40,723	40,723		Electric	928	40,723	
21	2021 SWEPCO Arkansas IRP filing		18,389	18,389		Electric	928	18,389	
22	2021 SWEPCO Louisiana IRP filing		26,907	26,907		Electric	928	26,907	
23	Arkansas 2021 Winter Storm		6,181	6,181		Electric	928	6,181	
24	Louisiana 2021 Winter Storm Inquiry		15,042	15,042		Electric	928	15,042	
25	Louisiana Winter Restoration Costs		11,355	11,355		Electric	928	11,355	
26	Louisiana Winter Storm Fuel Recovery		5,802	5,802		Electric	928	5,802	
27	Maverick Wind Facility		63,363	63,363		Electric	928	63,363	
28	Sunchase PPA Filing		(5,115)	(5,115)		Electric	928	(5,115)	
29	Sundance Wind Facility		43,924	43,924		Electric	928	43,924	
30	SWEPCO Arkansasa PPA Filing		(45)	(45)		Electric	928	(45)	
31	SWEPCO Louisiana AMI meter deployment		(30,161)	(30,161)		Electric	928	(30,161)	
32	SWEPCO Texas AMI meter deployment		(5,000)	(5,000)		Electric	928	(5,000)	
33	Texas 2021 Winter Storm Fuel Recovery		(266,549)	(266,549)		Electric	928	(266,549)	
34	Regulatory Fees	2,602,659		2,602,659		Electric	928	2,602,659	
35	2022 SWEPCO AR Turk Filing		299,495	299,495		Electric	928	299,495	
36	2022 SWEPCO TX Fuel Recncltn		272,063	272,063		Electric	928	272,063	
37	2023 SWEPCO DCRF Filing		54,688	54,688		Electric	928	54,688	
38	2023 SWEPCO LA IRP		890,784	890,784		Electric	928	890,784	
39	2023 SWEPCO TX TCRF Filing		148,376	148,376		Electric	928	148,376	
40	23 ARSWEP Formula Rate Review		326,749	326,749		Electric	928	326,749	
41	23 LASWEP Storm Securitization		442,875	442,875		Electric	928	442,875	
42	23SWEPTX Fuel Surcharge Filing		44,051	44,051		Electric	928	44,051	

						EXPENSES INCURRED 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)
43	AR 22 Renewable Gen from RFP		213,517	213,517		Electric	928	213,517	
44	EECRF Filing - SWEPCO		28,055	28,055		Electric	928	28,055	
45	LA 22 Renewable Gen from RFP		72,227	72,227		Electric	928	72,227	
46	Other Miscellaneous expense related to Regulatory and Legislative Actions in the State of Arkansas		31,868	31,868		Electric	928	31,868	
47	TX 22 Renewable Gen from RFP		46,113	46,113		Electric	928	46,113	
48	Traverse Wind Facility		220,506	220,506		Electric	928	220,506	
49	2022-23 APSC GEN PLANT EVAL		39,160	39,160		Electric	928	39,160	
50	2024 SWEPCO Arkansas IRP		2,001	2,001		Electric	928	2,001	
51	2023 ARSWEP Formula Rate Review		145,546	145,546		Electric	928	145,546	
52	2023 ARSWEPCO AMI Deployment		16,636	16,636		Electric	928	16,636	
53	2023 Audit 2021 AR Winter Storm		100,687	100,687		Electric	928	100,687	
54	2023 LASWEP Environmental Clause Audit		10,510	10,510		Electric	928	10,510	
55	2024 SWEPCO AR Formula Rate Review		324	324		Electric	928	324	
56	16 - Various Rate Case Epxenses Pending Future Approval for Collection from State Commission Authorities				8,258,886	Electric	928		2,401,542
46	TOTAL	2,602,660	5,562,778	8,165,438	9,168,867			6,361,205	2,401,542

	AMORTIZED DURING YEAR		
Line No.	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1			
2		1,804,232	(894,251)
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	AMORTIZED DURING YEAR		
Line No.	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
54			
55			
56			10,660,428
46		1,804,232	9,766,177

Name of Respondent: SWEPCO	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	A. (2) Transmission	RD&D Program Management	6,240		566	6,240	
2		2 Items < $50,000	65		566	65	
3		EPRI Research Portfolio		218,982	566	218,982	
4	A. (3) Distribution	1 Item < $50,000	7,277		588	7,277	
5				529,533	506	529,533	
6				84,081	588	84,081	
7	A. (5) Environmental (other than equipment)	Environmental Science & Controls Program Management					
8		2 Items < $50,000	475		506	475	
9		IT - EPRI Annual Research Portfolio		34,079	588	34,079	
10		Low Carbon Resource Initiative		59,985	506	59,985	
11	A. (6) Other	2 Items < $50,000	72		506	72	
12			79		566, 588	79	
13		26 Items < $50,000		59,950	506	59,950	
14	A. (1) Generation						
15	A. (6)(a) Solar	Solar Field Panel Testing			0.00		
16				34,111	566	34,111	
17				32,645	588	32,645	
18	A. (6)(f) Metering	Advanced Metering Equipment (AMI) Test Bed Development	1,159		588	1,159	
19	B. (4) Research Support to Others	3 Items < $50,000		1,505	506	1,505	
20	A. (6)(g) Research General	DTC Walnut Test Facility	1,243		566, 588	1,243	
21				1,639	566	1,639	
22	B. (5) Total Cost Incurred Externally			1,639,882		1,639,882	
23		1 Items < $50,000					
24	A. (7) Total Cost Incurred Internally		109,061			109,061	
25		Total	136,044	1,639,882		1,775,926	
26	(b) Fossil-fuel Steam	Generation Asset Management					

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: Amount (f)	Unamortized Accumulation (g)
27	B. Electric R&D External	5 Items < $50,000		2,509	506	2,509	
28	B. Electric R&D External	5 Items < $50,000		45,861	506, 566, 588	45,861	
29	B. (1) Electric Power Research Institute	EPRI Environmental Controls					
30		EPRI Environmental Science		625,971	506	625,971	
31		EPRI Research Portfolio		276,139	566	276,139	
32		IT - EPRI Annual Research Portfolio		31,121	588	31,121	
33		Low Carbon Resource Initiative		314,082	506	314,082	
34		26 Items < $50,000		841,107	506, 566, 588	841,107	
35	B. (4) Research Support to Others	3 Items < $50,000		189	506, 566	189	
36	B. (5) Total Cost Incurred Externally			2,134,470		2,134,470	
37		Total	109,061	2,134,470		2,243,531	
38				17,272	566	17,272	
39		Program Management					
40		3 Items < $50,000	92,063		506	92,063	
41				26,697	588	26,697	
42	(e) Unconventional Generation	Center for Energy Advancement Through Technological Membership	387		506	387	
43	B. (1) Electric Power Research Institute	EPRI Environmental Controls		78,973	506	78,973	
44		EPRI Environmental Science		457,921	506	457,921	

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Name of Respondent: SWEPCO	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	29,088,654		
4	Transmission	2,682,019		
5	Regional Market			
6	Distribution	11,959,287		
7	Customer Accounts	3,676,824		
8	Customer Service and Informational	3,466,064		
9	Sales			
10	Administrative and General	2,189,267		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	53,062,115		
12	Maintenance			
13	Production	11,847,121		
14	Transmission	2,183,743		
15	Regional Market			
16	Distribution	18,923,071		
17	Administrative and General	1,395,585		
18	TOTAL Maintenance (Total of lines 13 thru 17)	34,349,520		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	40,935,775		
21	Transmission (Enter Total of lines 4 and 14)	4,865,762		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	30,882,358		
24	Customer Accounts (Transcribe from line 7)	3,676,824		
25	Customer Service and Informational (Transcribe from line 8)	3,466,064		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	3,584,852		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	87,411,635	4,245,102	91,656,737
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)	87,411,635	4,245,102	91,656,737
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	47,068,457	2,285,855	49,354,312
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	47,068,457	2,285,855	49,354,312
72	Plant Removal (By Utility Departments)			
73	Electric Plant	9,391,149	456,076	9,847,225
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	9,391,149	456,076	9,847,225
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	151 - Fuel Stock	298,403		298,403
80	152 - Fuel Stock Undistributed	4,241,515		4,241,515
81	154 - Materials and Supplies			
82	163 - Stores Expense Undistributed	3,993,925	(3,993,925)	
83	165 - Other Prepayments			
84	182 - Other Regulatory Assets			
85	183 - Prelim Survey	7,365	(7,365)	
86	184 - Clearing Accounts	2,985,743	(2,985,743)	
87	185 - ODD Temporary Facilities	261,048		261,048
88	186 - Misc Deferred Debits	216,574		216,574
89	242 - Misc Current & Accrued Liab	28,669		28,669
90	254 - Ohio Reliability			
91	401 - Operation Expense - Nonassociated			
92	402 - Maintenance Exp			
93	421 - Misc Nonoperating Income			
94	426 - Political Activities	198,709		198,709
95	456 - Other Electric Revenue	(34,167)		(34,167)
95	TOTAL Other Accounts	12,197,784	(6,987,033)	5,210,751
96	TOTAL SALARIES AND WAGES	156,069,025		156,069,025

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Name of Respondent: SWEPCO	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.

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

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	21,074,276	55,382,112	94,152,362	134,249,073
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(11,697,473)	(23,605,146)	(35,832,608)	(40,994,256)
4	Transmission Rights				
5	Ancillary Services	3,432,877	5,778,501	8,682,893	11,657,350
6	Other Items (list separately)				
7	Congestion	19,716,227	31,469,052	46,808,235	64,118,782
8	Operating Reserves	1,911,610	1,224,880	1,489,381	1,438,780
9	Transmission Congestion Revenue	(13,285,253)	(46,521,108)	(59,078,081)	(71,724,396)
10	Transmission Losses	1,978,794	2,750,004	4,805,282	6,825,757
46	TOTAL	23,131,058	26,478,295	61,027,464	105,571,090

Name of Respondent: SWEPCO	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						
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: SWEPCO	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	[(b)]0

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Name of Respondent: SWEPCO	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
Southwestern Electric Power Company's transmission service is administered through a Regional Transmission Organization (RTO) and requested information is not available on an individual company basis.
(b) Concept: OtherService
Southwestern Electric Power Company's transmission service is administered through a Regional Transmission Organization (RTO) and requested information is not available on an individual company basis.

Name of Respondent: SWEPCO	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: SWEPCO	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)	16,894,653
3	Steam	13,131,629	23	Requirements Sales for Resale (See instruction 4, page 311.)	4,597,872
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,269,518
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	33,671
7	Other	2,769,529	27	Total Energy Losses	1,284,490
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	15,901,158	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	24,080,204
10	Purchases (other than for Energy Storage)	8,179,046			
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)	24,080,204			

Name of Respondent: SWEPCO	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	2,002,545	165,803	3,655	31	19
30	February	1,745,554	89,169	3,659	1	10
31	March	1,764,273	141,098	3,481	20	8
32	April	1,738,191	152,813	3,117	3	18
33	May	2,000,153	87,580	3,559	31	17
34	June	2,174,299	109,819	4,498	29	17
35	July	2,795,276	399,182	4,552	18	17
36	August	2,738,354	133,670	4,886	24	16
37	September	1,762,555	(201,582)	4,589	7	17
38	October	1,800,212	130,511	3,525	2	17
39	November	1,688,816	17,002	3,307	27	8
40	December	1,869,976	66,198	3,427	29	8
41	Total	24,080,204	1,291,263			

Name of Respondent: SWEPCO	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: [a] *Dolet Hills (3)	Plant Name: [b] *Flint Creek (1)	Plant Name: [c] *Pirkey (2)	Plant Name: [d] Arsenal Hill	Plant Name: Harry D Mattison	Plant Name: [e] Knox Lee	Plant Name: [f] Lieberman	Plant Name: North Central Wind	Plant Name: [g] Turk (4)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Steam	Steam	Steam	Gas Turbine	Steam	Steam	Wind	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler	Outdoor Boiler	Outdoor Boiler	Outdoor Boiler	No Boiler	Outdoor Boiler	Outdoor Boiler	Wind Generator	Outdoor Boiler
3	Year Originally Constructed	1986	1978	1985	1960	2007	1950	1947	2021	2012
4	Year Last Unit was Installed	1986	1978	1985	2010	2007	1974	1959	2022	2012
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	289.97	279.00	619.34	741.00	349.00	351.00	228.00	816.55	523.58
6	Net Peak Demand on Plant - MW (60 minutes)		274	563	685	306	349	207	722	482
7	Plant Hours Connected to Load		7,669	2,865	7,653	792	3,732	1,837	8,250	7,045
8	Net Continuous Plant Capability (Megawatts)		259	580	622	283	335	219		477
9	When Not Limited by Condenser Water									0
10	When Limited by Condenser Water		259	580	622	283	335	219		477
11	Average Number of Employees		89	33	26	5	25	23	31	110
12	Net Generation, Exclusive of Plant Use - kWh		1,062,190,000	742,138,000	3,714,173,000	177,190,000	476,641,000	139,249,000	2,646,904,432	2,302,392,000
13	Cost of Plant: Land and Land Rights		3,086,010		370,798	1,408,956	102,781	24,026	356,544	13,355,616
14	Structures and Improvements		45,169,957		61,431,062	31,365,232	10,104,043	5,797,165	319,007	302,455,895
15	Equipment Costs		342,201,836		407,425,898	98,283,144	54,885,664	36,395,725	1,061,167,195	1,371,887,826
16	Asset Retirement Costs		12,402,374		507,714		1,350,801	2,963,517	24,544,414	3,669,588
17	Total cost (total 13 thru 20)		402,860,177		469,735,472	131,057,332	66,443,289	45,180,433	1,086,387,160	1,691,368,925
18	Cost per KW of Installed Capacity (line 17/5) Including		1,444		634	376	189	198	1,330	3,230
19	Production Expenses: Oper, Supv, & Engr		1,623,853.0000	1,531,684.0000	3,282,022	101,574.0000	828,075	241,262	997,537	3,105,803.0000
20	Fuel	1,690,133	29,461,669	47,416,608	81,352,792	9,469,122	14,383,721	4,505,720		60,621,675
21	Coolants and Water (Nuclear Plants Only)									
22	Steam Expenses		1,105,385	3,093,059	1,216,238	14,585	1,799,545	3,189,924	4,615	4,943,941
23	Steam From Other Sources									
24	Steam Transferred (Cr)									
25	Electric Expenses		1,258,555	785,955	2,609,585	255,656	(391)	3,716	936,498	404,951
26	Misc Steam (or Nuclear) Power Expenses	949,753	819,516	943,358	1,083,564	736	321,035	93,626	94,714	1,438,632
27	Rents									
28	Allowances		85,088	24,777	134,858	69,999	40,494	9,818		76,869
29	Maintenance Supervision and Engineering		511,676	33,537	114,234	6,220	15,511	4,629	1,913	1,146,744
30	Maintenance of Structures	(13,181)	819,742	35,546	512,377	80,724	869,747	313,994		1,631,468
31	Maintenance of Boiler (or reactor) Plant	8,118	2,926,162	1,043,990	3,337,185	554	2,061,200	1,550,288		4,031,193
32	Maintenance of Electric Plant	507	386,663	165,098	6,284,776	1,222,635	242,904	520,536	3,758,433	912,553
33	Maintenance of Misc Steam (or Nuclear) Plant	134,421	1,255,625	741,318	874,561	285	5,505	739		1,230,892
34	Total Production Expenses	2,769,751	40,253,934	55,814,930	100,802,192	11,222,090	20,567,346	10,434,252	5,793,709	79,544,721
35	Expenses per Net kWh		0.0379	0.0752	0.0271	0.0633	0.0432	0.0749	0.0022	0.0345

Line No.	Item (a)	Plant Name: Welsh	Plant Name: [h] Wilkes
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler	Outdoor Boiler
3	Year Originally Constructed	1977	1964
4	Year Last Unit was Installed	1982	1971
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	558.00	882.00
6	Net Peak Demand on Plant - MW (60 minutes)	1,056	817
7	Plant Hours Connected to Load	6,189	4,606
8	Net Continuous Plant Capability (Megawatts)	1,053	864
9	When Not Limited by Condenser Water		
10	When Limited by Condenser Water	1,053	864
11	Average Number of Employees	120	34
12	Net Generation, Exclusive of Plant Use - kWh	3,579,705,000	1,115,141,000
13	Cost of Plant: Land and Land Rights	1,895,474	443,729
14	Structures and Improvements	74,806,738	9,063,507
15	Equipment Costs	816,120,510	125,388,329
16	Asset Retirement Costs	29,104,815	4,897,017
17	Total cost (total 13 thru 20)	921,927,537	139,792,582
18	Cost per KW of Installed Capacity (line 17/5) Including	1,652	158
19	Production Expenses: Oper, Supv, & Engr	3,612,761.0000	1,381,003
20	Fuel	105,882,304	36,928,786
21	Coolants and Water (Nuclear Plants Only)		
22	Steam Expenses	5,285,228	347,260
23	Steam From Other Sources		
24	Steam Transferred (Cr)		
25	Electric Expenses	2,539,255	2,361,166
26	Misc Steam (or Nuclear) Power Expenses	4,697,471	794,004
27	Rents		
28	Allowances	435,196	109,542
29	Maintenance Supervision and Engineering	132,946	317,919
30	Maintenance of Structures	759,350	625,559
31	Maintenance of Boiler (or reactor) Plant	7,879,782	5,107,013
32	Maintenance of Electric Plant	5,283,041	1,489,178
33	Maintenance of Misc Steam (or Nuclear) Plant	1,070,393	414,120
34	Total Production Expenses	137,577,727	49,875,550
35	Expenses per Net kWh	0.0384	0.0447

35	**Plant Name**	*Dolet Hills (3)	*Dolet Hills (3)	*Dolet Hills (3)	*Flint Creek (1)	*Flint Creek (1)	*Flint Creek (1)	*Pirkey (2)	*Pirkey (2)	*Pirkey (2)	Arsenal Hill	Arsenal Hill	Harry D Mattison
36	Fuel Kind	COMPOSITE	GAS	LIGNITE	COAL	COMPOSIT	OIL	COMPOSITE	GAS	LIGNITE	GAS	OIL	GAS
37	Fuel Unit				t		bbl		Mcf	t	Mcf	bbl	Mcf
38	Quantity (Units) of Fuel Burned				673,182		5,610		14,228	652,463	26,629,159		2,037,495
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)				8,910		187,800		1,000	6,241.000	1,033		1,025
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year				37.290		130.570		1.240	70.030	3.030		4.620
41	Average Cost of Fuel per Unit Burned				37.000		130.570		1.240	67.470	3.030		4.620
42	Average Cost of Fuel Burned per Million BTU				2.080		16.550		1.240	5.410	2.930		4.510
43	Average Cost of Fuel Burned per kWh Net Gen				0.020		0.190		0.010	0.060	0.020		0.050
44	Average BTU per kWh Net Generation				11,334.000	11,335.000	11,455	10,993.000	10,970.000	10,993.000	7,408.000		11,785.000

35	**Plant Name**	Knox Lee	Knox Lee	Knox Lee	Lieberman	Lieberman	Lieberman	North Central Wind	Turk (4)	Turk (4)	Turk (4)	Welsh	Welsh
36	Fuel Kind	COMPOSITE	GAS	OIL	COMPOSIT	GAS	OIL	Wind	COAL	COMPOSIT	GAS	COAL	COMPOSIT
37	Fuel Unit		Mcf	bbl		Mcf	bbl		t		Mcf	t	
38	Quantity (Units) of Fuel Burned		5,318,473			1,695,043			1,210,688		89,189	2,237,139	
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)		1,009.000			1,029			8,916		1,034	9,240	
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year		2.680			2.630			45.780		3.200	44.700	
41	Average Cost of Fuel per Unit Burned		2.680			2.630			45.580		3.200	44.980	
42	Average Cost of Fuel Burned per Million BTU		2.660			2.560			2.560		3.090	2.430	
43	Average Cost of Fuel Burned per kWh Net Gen		0.030			0.030			0.020		0.030	0.030	
44	Average BTU per kWh Net Generation	11,254.000	11,254.000		12,524.0000	12,524.000			9,415.000	9,417.000	9,862.000	11,575.000	11,575.000

35	**Plant Name**	Welsh	Wilkes	Wilkes	Wilkes
36	Fuel Kind	OIL	COMPOSITE	GAS	OIL
37	Fuel Unit	bbl		Mcf	bbl
38	Quantity (Units) of Fuel Burned	15,916		12,227,964	74
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	143,736		1,028	140,000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	127.110		2.990	70.320
41	Average Cost of Fuel per Unit Burned	127.110		2.990	70.320
42	Average Cost of Fuel Burned per Million BTU	21.060		2.910	11.960
43	Average Cost of Fuel Burned per kWh Net Gen	0.250		0.030	0.150
44	Average BTU per kWh Net Generation	11,679.00	11,270.000	11,270.000	12,135.000

Name of Respondent: SWEPCO	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: PlantName

(3) Dolet Hills Power Station is jointly owned in the percentages shown below:

Southwestern Electric Power Company	40.234 %
Central Louisiana Electric Company	50.000 %
Northeast Texas Electric Cooperative	5.860 %
Oklahoma Municipal Power Authority	3.906 %
Total	100.000 %

(b) Concept: PlantName

(1) Flint Creek Power Station is jointly owned in the percentages shown below:

Southwestern Electric Power Company	50 %
Arkansas Electric Cooperative Corporation	50 %
Total	100 %

(c) Concept: PlantName

(2) Pirkey Power Station is jointly owned in the percentages shown below:

Southwestern Electric Power Company	85.936 %
Northeast Texas Electric Cooperative	11.720 %
Oklahoma Municipal Power Authority	2.344 %
Total	100.000 %

(d) Concept: PlantName

Arsenal Hill Unit 6 (J. Lamar Stall Unit), a natural gas-fired combustion turbine combined cycle generating unit, became operational in June 2010. Unit 6 consists of 2 combustion turbines feeding one steam turbine.

(e) Concept: PlantName

Knox Lee Plant - Units 2 and 3 were retired during May 2020 business.

(f) Concept: PlantName

Lieberman Plant - Unit 2 was retired during May 2020 business.

(g) Concept: PlantName

Turk Plant, a 600MW Ultra-supercritical coal unit, became operational in December 2012.

(4) Turk Power Station is jointly owned in the percentages shown below:

Southwestern Electric Power Company	73.33 %
Arkansas Electric Cooperative Corporation	11.67 %
East Texas Electric Cooperative	8.33 %
Oklahoma Municipal Power Authority	6.67 %
Total	100.000 %

In April 2021, SWEPCo acquired a 54.5% ownership share of Sundance wind facility (199 MW total nameplate capacity) which was placed in-service in April 2021.

In September 2021, SWEPCo acquired a 54.5% ownership share of Maverick wind facility (287 MW total nameplate capacity) which was placed in-service in September 2021.

(h) Concept: PlantName

Lone Star Plant was retired during May 2020 business.

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Hydroelectric Generating Plant Statistics

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

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

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Pumped Storage Generating Plant Statistics

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	0
6	Plant Hours Connect to Load While Generating	0
7	Net Plant Capability (in megawatts)	0
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	0
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	**Cost of Plant**	
13	Land and Land Rights	
14	Structures and Improvements	0
15	Reservoirs, Dams, and Waterways	0
16	Water Wheels, Turbines, and Generators	0
17	Accessory Electric Equipment	0
18	Miscellaneous Powerplant Equipment	0
19	Roads, Railroads, and Bridges	0
20	Asset Retirement Costs	0
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	**Production Expenses**	
24	Operation Supervision and Engineering	0
25	Water for Power	0
26	Pumped Storage Expenses	0
27	Electric Expenses	0
28	Misc Pumped Storage Power generation Expenses	0
29	Rents	0
30	Maintenance Supervision and Engineering	0
31	Maintenance of Structures	0
32	Maintenance of Reservoirs, Dams, and Waterways	0
33	Maintenance of Electric Plant	0
34	Maintenance of Misc Pumped Storage Plant	0
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

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Name of Respondent: SWEPCO	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)
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Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
42													
43													
44													
45													
46													

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Name of Respondent: SWEPCO	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 generator's own load requirements or used for the provision of 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 how the cost of the power was determined. In columns (n) 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, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	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)
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35	TOTAL			0	0	0	0	0	0	0	0	0

Line No.	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)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Account for Project Costs (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
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32							
33							
34							
35	0	0	0		0	0	0

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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)
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3									
4									
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32									
33									
34									
35									
36	TOTAL								

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TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	TL367 Layfield Extension		500.00	500.00	1	0.08	0	1	3-1272 ACSR
2	345 kV in AR	345 kV in AR	0	0		0.00	0	0	
3	TL149 Flint Creek	GRDA GRDA 1 (Interconnect)	345	345	2	3.04	0	1	2x1431.0 ACSR
4	TL149 Flint Creek	CUS Brookline (Interconnect	345	345	3	17.92	0	1	2156.0 ACSR
5	TL175 Chamber Springs	Clarksville 345	345	345	1	6.85	0	1	2x795.0 ACSR
6	TL288 Chambers Spring	Tontitown	345.00	345.00	1	11.53	0	1	2x795.0 ACSR
7	TL327 Turk (AR)	NW Texarkana	345.00	345.00	2	22.15	0	1	954.0 ACSR
8	TL344 Flint Creek	Shipe Road	345.00	345.00	1	14.40	0	1	2x954.0 ACSR
9	345 kV in LA	345 kV in LA	0.00	0.00		0.00	0	0	
10	TL133 Southwest Shreveport	CLECO Dolet Hills	345.00	345.00	3	34.60	0	1	2156.0 ACSR
11	TL134 Diana	Southwest Shreveport	345.00	345.00	3	3.30	8	1	2156.0 ACSR
12	TL134 Diana	Southwest Shreveport	0.00	0.00		0.00	0	0	2x795.0 ACSR
13	TL134 Longwood	Southwest Shreveport	345.00	345.00	1	19.02	0	1	2x795.0 ACSR
14	TL135 Longwood	Entergy El Dorado	345.00	345.00	2	37.72	0	1	2x1024.0 ACAR
15	TL135 Longwood	Wilkes	345.00	345.00	3	3.06	0.00	1	2x1024.0 ACAR
16	345 kV in OK	345 kV in OK	0.00	0.00		0.00	0.00	0	
17	TL251 Chamber Springs	Clarksville 345	345.00	345.00	1	61.57	0.00	1	2x795.0 ACSR
18	345 kV in TX	345 kV in TX	0.00	0.00		0.00	0.00	0	
19	TL199 Welsh	Monticello	345.00	345.00	3	16.00	0.00	1	2156 ACSR
20	TL199 Welsh	Welsh DC	345.00	345.00	3	0.48	0.00	0	2156.0 ACSR
21	TL270 Lydia	NW Texarkana	345.00	345.00	1	0.14	0.00	1	2156.0 ACSR
22	TL270 Lydia	NW Texarkana	345.00	345.00	3	31.20	0.00	1	2156.0 ACSR
23	TL271 Longwood	Wilkes	345.00	345.00	2	0.23	0.00	1	2x1024.0 ACAR
24	TL271 Longwood	Wilkes	345.00	345.00	3	35.11	0.00	0	2x1024.0 ACAR
25	TL271 Lydia	Valliant	345.00	345.00	1	0.16	0.00	1	2x795 ACSR
26	TL271 Lydia	Valliant	345.00	345.00	3	22.45	0.00	0	2x795 ACSR
27	TL271 Welsh	Wilkes	345.00	345.00	3	30.61	0.00	1	2x795 ACSR
28	TL271 Welsh	Lydia	345.00	345.00	1	0.16	0.00	1	2x795 ACSR
29	TL271 Welsh	Lydia	345.00	345.00	3	23.74	0.00	0	2156.0 ACSR
30	TL272 Diana	Southwest Shreveport	345.00	345.00	3	46.45	0.00	1	2156.0 ACSR
31	TL273 Crockett	Entergy Grimes	345.00	345.00	3	26.40	0.00	1	2x1024.0 ACAR
32	TL273 Crockett	Tenaska Rusk County	345.00	345.00	3	65.61	0.00	1	2x1024.0 ACAR
33	TL273 Crockett	Tenaska Rusk County	345.00	345.00	2	1.53	0.00	1	2x1024.0 ACAR
34	TL273 Diana	Pirkey	345.00	345.00	3	24.70	0.00	1	2x1024.0 ACAR
35	TL273 Lebrock	Tenaska Rusk County	345.00	345.00	3	29.31	0.00	0	2x1024.0 ACAR
36	TL273 Lebrock	Tenaska Rusk County	345.00	345.00	3	8.70	0.00	0	2x1272.0 ACSR
37	TL274 Northwest Texarkana	Welsh	345.00	345.00	3	51.68	12.00	1	2156.0 ACSR
38	TL274 Northwest Texarkana	Welsh	0.00	0.00	2	0.31	0.00	0	2156.0 ACSR
39	TL274 Northwest Texarkana	Welsh	0.00	0.00	1	1.31	0.00	0	2156.0 ACSR
40	TL275 Diana	Welsh Ckt 1	345.00	345.00	3	23.69	0.00	1	2156.0 ACSR
41	TL275 Diana	Welsh Ckt 2	345.00	345.00	3	23.60	0.00	1	2156.0 ACSR
42	TL281 Lebrock	Pirkey	345.00	345.00	1	5.21	0.00	1	2x1272.0 ACSR
43	TL281 Lebrock	Pirkey	0.00	0.00	2	0.90	0.00	0	
44	TL328 Turk (TX)	NW Texarkana	345.00	345.00	2	7.43	0.00	1	954.0 ACSR
45	TL90928 Valliant	NW Texarkana (TX Portion)	345.00	345.00	1	43.48	0.00	1	2-954 ACSR
46	161 kV in AR	161 kV in AR	0.00	0.00		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)
47	TL154 VBI	Rogers/Loop Thru Springdale (TLN194:0154G)	161.00	161.00	1	4.40	0.00	1	1590.0 ACSR
48	TL162 Midland	Huntington - REA - Boonevil	161.00	161.00	1	12.70	0.00	1	397.0 ACSR
49	TL162 Midland	Huntington - REA - Boonevil	161.00	161.00	1	6.80	0.00	2	477.0 ACSR & 397.
50	TL162 Midland	Huntington - REA - Boonevil	161.00	161.00	1	13.96	0.00	1	397.0 ACSR
51	TL172 Siloam Springs	West Siloam Springs (GRDA)	161.00	161.00	1	2.06	0.00	1	1272.0 ACSR
52	TL176 OG&E	Fort Smith - Bonanza - Nort	161.00	161.00	2	13.10	0.00	1	397.0 ACSR
53	TL176 OG&E	Fort Smith - Bonanza - Nort	161.00	161.00	2	0.24	0.00	1	1590.0 ACSR
54	TL177 Flint Creek	Dyess Substation	161.00	161.00	1	5.63	0.00	2	2x397.0 ACSR
55	TL177 Flint Creek	Dyess Substation	161.00	161.00	2	10.59	0.00	1	2x397.0 ACSR
56	TL177 Flint Creek	Dyess Substation	161.00	161.00	1	5.46	0.00	1	2156 ACSR
57	TL177 Flint Creek	Dyess Substation	161.00	161.00	1	1.60	0.00	1	1590 ACSR
58	TL177 Flint Creek	Dyess Substation	161.00	161.00	1	5.63	0.00	2	1020 ACCC
59	TL178 Flint Creek	Siloam Springs Substation	161.00	161.00	1	5.44	0.00	1	2x397.0 ACSR
60	TL178 Flint Creek	Siloam Springs Substation	161.00	161.00	2	1.68	0.00	1	2x397.0 ACSR
61	TL179 Chambers Spring	South Fayetteville	161.00	161.00	1	10.36	0.00	1	2156 ACSR
62	TL179 Chambers Spring	South Fayetteville	0.00	0.00	2	5.70	0.00	0	2x397.0 ACSR
63	TL179 Flint Creek	South Fayetteville Substati	161.00	161.00	1	0.22	0.00	1	1272.0 ACSR
64	TL179 Flint Creek	South Fayetteville Substati	161.00	161.00	2	2.24	0.00	2	2x397.0 ACSR
65	TL179 Flint Creek	South Fayetteville Substati	161.00	161.00	1	3.45	0.00	1	2x397.0 ACSR
66	TL179 Flint Creek	South Fayetteville Substati	161.00	161.00	2	7.74	0.00	1	2x397.0 ACSR
67	TL180 Flint Creek	East Centerton	161.00	161.00	1	7.99	0.00	1	1272.0 ACSR
68	TL180 Flint Creek	East Centerton	161.00	161.00	1	1.87	0.00	1	1590.0 ACSR
69	TL180 Flint Creek	East Centerton	161.00	161.00	1	10.40	0.00	1	2156.0 ACSR
70	TL180 Flint Creek	East Centerton	161.00	161.00	1	8.63	0.00	1	1590.0 ACSR
71	TL180 Flint Creek	East Centerton	161.00	161.00	1	0.40	0.00	1	1020 ACCC
72	TL187 SPA	Eureka Springs Double Circu	161.00	161.00	2	1.25	0.00	1	795.0 ACSR
73	TL187 SPA Eur Spr	Eureka Springs Double Circu	161.00	161.00	2	1.25	0.00	1	795.0 ACSR
74	TL188 Eureka Springs	AP&L Interconnection	161.00	161.00	1	0.94	0.00	1	666.0 ACSR
75	TL188 Eureka Springs	AP&L Interconnection	161.00	161.00	2	4.40	0.00	1	666.0 ACSR
76	TL189 Dyess	Beaver Dam	161.00	161.00	1	6.84	0.00	1	2156.0 ACSR
77	TL189 Dyess	Beaver Dam	0.00	0.00	2	30.23	0.00	1	666.0 ACSR
78	TL189 Dyess	Beaver Dam	0.00	0.00	2	11.70	0.00	1	1020.0 ACCC/TW
79	TL189 Dyess	Beaver Dam	0.00	0.00	2	0.66	0.00	2	2156.0 ACSR
80	TL190 South Fayetteville	South Springdale - Dyess	161.00	161.00	1	5.50	0.00	1	1272.0 AAC
81	TL190 South Fayetteville	South Springdale - Dyess	161.00	161.00	1	0.02	0.00	1	1272.0 ACSR
82	TL190 South Fayetteville	South Springdale - Dyess	161.00	161.00	2	8.83	0.00	1	2x397.0 ACSR
83	TL190 South Fayetteville	South Springdale - Dyess	161.00	161.00	1	0.78	0.00	2	2x397.0 ACSR
84	TL190 South Fayetteville	South Springdale - Dyess	161.00	161.00	1	2.11	0.00	1	2x397.0 ACSR
85	TL190 South Fayetteville	South Springdale - Dyess	161.00	161.00	1	2.96	0.00	1	2x397.0 ACSR
86	TL282 East Rogers	Rogers	161.00	161.00	1	1.25	0.00	1	1272.0 ACSR
87	TL282 East Rogers	Rogers	161.00	161.00	1	3.92	0.00	1	1590 ACSR
88	TL283 Tontitown	Lowell	161.00	161.00	1	11.59	0.00	1	1590.0 ACSR
89	TL283 Tontitown	Lowell	161.00	161.00	1	0.40	0.00	2	1590.0 ACSR
90	TL283 Tontitown	Lowell	161.00	161.00	1	0.40	0.00	2	2156 ACSR
91	TL285 Siloam Springs	Chambers Spring	161.00	161.00	1	7.56	0.00	1	1590.0 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)
92	TL337 North Magazine	Danville (Entergy)	161.00	161.00	1	25.95	0.00	1	1272.0 ACSR
93	TL340 Van Asche	Dyess	161.00	161.00	1	5.97	0.00	1	1590.0 ACSR
94	TL341 Fayetteville	S Fayetteville	161.00	161.00	1	1.98	0.00	1	1590.0 ACSR
95	TL342 Fayetteville	Van Asche	161.00	161.00	1	4.18	0.00	1	1590.0 ACSR
96	TL343 East Centerton	Shipe Road	161.00	161.00	1	6.79	0.00	1	2156 ACSR
97	TL360 Osburn Tap		161.00	161.00	1	1.61	0.00	2	1272.0 ACSR
98	TL389 Greenland	VBI	69.00	161.00	1	40.70	0.00	1	1272 ACSR
99	TL425 Branch	North Magazine	161.00	161.00	2	9.01	0.00	1	250.0 CW
100	138 kV in AR	138 kV in AR	0.00	0.00		0.00	0.00	0	
101	TL159 DeQueen	Craig Junction	138.00	138.00	1	8.21	0.00	1	1272 ACSR
102	TL181 Northwest Texarkana	Patterson	138.00	138.00	2	8.26	0.00	1	1024.0 ACAR
103	TL181 Northwest Texarkana	Patterson (TLN194:00181)	138.00	138.00	1	0.40	0.00	2	1590 ACSR
104	TL181 Northwest Texarkana	Patterson (TLN194:00181A)	138.00	138.00	1	1.71	0.00	2	1272.0 ACSR
105	TL181 Northwest Texarkana	Patterson (TLN194:00181A)	138.00	138.00	1	23.41	0.00	1	1272.0 ACSR
106	TL181 Northwest Texarkana	Patterson (TLN194:00181A)	138.00	138.00	1	0.24	0.00	2	1590 ACSR
107	TL181 Northwest Texarkana	Patterson (TLN194:00181A)	138.00	138.00	1	0.07	0.00	1	1590 ACSR
108	TL181 Northwest Texarkana	Patterson (TLN194:00181B)	138.00	138.00	1	0.04	0.00	1	1272 ACSR
109	TL181 Northwest Texarkana	Patterson (TLN194:00181B)	138.00	138.00	2	18.01	0.00	1	4/0 CU
110	TL182 Patterson	Craig Junction	138.00	138.00	1	26.47	0.00	1	1272.0 ACSR
111	TL182 Patterson	Craig Junction	138.00	138.00	2	0.48	0.00	1	1272.0 ACSR
112	TL182 Patterson	Craig Junction	138.00	138.00	1	0.18	0.00	2	1590.0 ACSR
113	TL183 North New Boston	Patterson	138.00	138.00	2	0.10	0.00	1	2x203.2 ACSR
114	TL183 North New Boston	Patterson	138.00	138.00	2	17.09	0.00	1	666.0 ACSR
115	TL184 South Dierks	Patterson	138.00	138.00	1	2.28	0.00	1	2x397.0 ACSR
116	TL184 South Dierks	Patterson	138.00	138.00	2	19.09	0.00	1	2x397.0 ACSR
117	TL184 South Dierks	Patterson	138.00	138.00	2	10.90	0.00	1	397.0 ACSR
118	TL184 South Dierks	Patterson	138.00	138.00	1	0.07	0.00	1	1590 ACSR
119	TL227 Bann	Southeast Texarkana	138.00	138.00	1	0.20	0.00	2	1272.0 ACSR
120	TL227 Bann	Southeast Texarkana	138.00	138.00	1	0.18	0.00	1	1272.0 ACSR
121	TL235 Northwest Texarkana	Northeast Texarkana (Sugarhill)	138.00	138.00	1	0.50	0.00	2	1272.0 ACSR
122	TL280 Mena	Craig Jct.	138.00	138.00	1	28.22	0.00	1	795.0 ACSR
123	TL325 Turk	Sugar Hill	138.00	138.00	1	21.70	0.00	1	1590 ACSR
124	TL330 Turk	Southeast Texarkana	138.00	138.00	1	24.95	0.00	1	1590 ACSR/AW
125	TL330 Turk	Southeast Texarkana	138.00	138.00	1	1.84	0.00	2	1590 ACSR/AW
126	TL330 Turk	Southeast Texarkana	138.00	138.00	1	1.84	0.00	2	T2-397.5 ACSR
127	TL345 Turk	Hope	115.00	138.00	1	1.04	0.00	2	1590 ACSR
128	TL345 Turk	Hope	115.00	138.00	1	5.04	0.00	1	1590 ACSR
129	TL403 Wilkes 138kV Bus Tie		138.00	138.00	1	0.06	0.00	1	2x795 ACSS
130	138 kV in LA	138 kV in LA	0.00	0.00		0.00	0.00	0	
131	TL107 Western Electric Tee	Texas Station	138.00	138.00	1	9.74	0.00	1	1272.0 ACSR
132	TL107 Western Electric Tee	Texas Station	138.00	138.00	1	12.80	0.00	1	795.0 ACSR
133	TL107 Western Electric Tee	Texas Station (TLN194:0107A)	138.00	138.00	1	8.00	0.00	1	1272.0 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)
134	TL109 SW Shreveport - Powel	Linwood Substation	138.00	138.00	1	2.27	0.00	1	1272.0 AAC
135	TL109 SW Shreveport - Powel	Linwood Substation	138.00	138.00	2	0.26	0.00	1	1272.0 ACSR
136	TL109 SW Shreveport - Powel	Linwood Substation	138.00	138.00	1	6.80	0.00	1	1703.0 ACAR
137	TL110 Shreveport 138kV Loop	(TLN194:00110)	138.00	138.00	1	2.72	0.00	1	2156 ACSR
138	TL110 Shreveport 138kV Loop	(TLN194:00110)	138.00	138.00	1	0.62	0.00	2	2156 ACSR
139	TL110 Shreveport 138kV Loop	(TLN194:00110)	138.00	138.00	1	0.62	0.00	2	666.6 ACSR
140	TL110 Shreveport 138kV Loop	(TLN194:0110A)	138.00	138.00	1	2.91	0.00	1	1272.0 AAC
141	TL110 Shreveport 138kV Loop	(TLN194:0110A)	138.00	138.00	1	2.12	0.00	0	1272.0 ACSR
142	TL110 Shreveport 138kV Loop	(TLN194:0110B)	138.00	138.00	1	8.90	0.00	1	1272.0 AAC
143	TL110 Shreveport 138kV Loop	(TLN194:0110B)	138.00	138.00	1	1.50	0.00	2	1272.0 AAC & 666.6 ACSR
144	TL110 Shreveport 138kV Loop	(TLN194:0110C)	138.00	138.00	1	2.45	0.00	1	1533.3 ACSR/TW
145	TL112 Center	Logansport	138.00	138.00	1	0.60	0.00	1	755.0 ACAR
146	TL119 Minden Road Tee - Whi	Bodcau - Red Point (TLN194:00119)	138.00	138.00	1	6.86	0.00	1	2x397.0 ACSR
147	TL119 Minden Road Tee - Whi	Bodcau - Red Point (TLN194:0119A)	138.00	138.00	1	4.51	0.00	1	2x397.0 ACSR
148	TL122 Logansport	Rock Hill (LA)	138.00	138.00	2	4.35	0.00	1	755.0 ACAR
149	TL127 Arsenal Hill	Longwood	138.00	138.00	1	15.06	0.00	1	1272 ACSR
150	TL127 Arsenal Hill	Longwood	138.00	138.00	1	1.41	0.00	1	1233.6 ACSR
151	TL127 Arsenal Hill	Longwood	138.00	138.00	3	0.65	0.00	2	1024 ACAR
152	TL127 Marshall - Longwood - Arsenal Hill	Longwood - Lieberman (TLN194:0127A)	138.00	138.00	1	1.83	0.00	1	2156.0 ACSR
153	TL127 Marshall - Longwood - Arsenal Hill	Longwood - Lieberman (TLN194:0127A)	138.00	138.00	2	7.80	0.00	0	2x266.8 ACSR
154	TL128 Arsenal Hill	Lieberman	138.00	138.00	1	0.12	0.00	1	1272 ACSR
155	TL128 Arsenal Hill	Lieberman	138.00	138.00	2	10.93	0.00	1	666.6 ACSR
156	TL128 Arsenal Hill	Lieberman	138.00	138.00	1	1.94	0.00	1	959.6 ACSR/TW
157	TL128 Arsenal Hill	Lieberman	138.00	138.00	1	2.00	0.00	1	666.6 ACSR
158	TL128 Arsenal Hill	Lieberman	138.00	138.00	2	6.43	0.00	1	2-266 ACSR
159	TL128 Arsenal Hill	Lieberman	138.00	138.00	3	0.00	0.00	1	666.6 ACSR
160	TL129 Knox Lee - Rock Hill	South Shreveport/Tap - SW Shreveport (TLN194:00129)	138.00	138.00	1	6.90	0.00	1	1590.0 ACSR
161	TL129 Knox Lee - Rock Hill	South Shreveport/Tap - SW Shreveport (TLN194:0129A)	138.00	138.00	1	2.30	0.00	2	2-1590.0 ACSR
162	TL129 Knox Lee - Rock Hill	South Shreveport/Tap - SW Shreveport (TLN194:00129)	138.00	138.00	1	10.78	0.00	1	1272.0 ACSR
163	TL129 Knox Lee - Rock Hill	South Shreveport/Tap - SW Shreveport (TLN194:00129)	138.00	138.00	2	0.02	0.00	1	2x397.0 ACSR
164	TL129 Knox Lee - Rock Hill	South Shreveport/Tap - SW Shreveport (TLN194:00129)	138.00	138.00	1	4.25	0.00	1	1926.9 ACSR
165	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:00130)	138.00	138.00	1	0.58	0.00	1	666.0 ACSR
166	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:00130)	138.00	138.00	2	0.98	0.00	0	795.0 ACSR
167	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:0130A)	138.00	138.00	2	12.22	0.00	1	666.0 ACSR
168	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:0130B)	138.00	138.00	1	1.28	0.00	1	666.0 ACSR
169	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:0130B)	138.00	138.00	2	3.06	0.00	0	795.0 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)
170	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:0130C)	138.00	138.00	1	1.40	0.00	1	2x397.0 ACSR
171	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:0130C)	138.00	138.00	2	4.91	0.00	1	2x397.0 ACSR
172	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:0130D)	138.00	138.00	1	1.48	0.00	1	2x795.0 ACSR
173	TL130 South Shreveport - We	Flournoy - Longwood (TLN194:0130D)	138.00	138.00	2	3.40	0.00	1	2x795.0 ACSR
174	TL131 South Shreveport	Frierson (Cleco Interconnection) (TLN194:00131)	138.00	138.00	2	11.18	0.00	1	666.0 ACSR
175	TL131 South Shreveport	Frierson (Cleco Interconnection) (TLN194:0131A)	138.00	138.00	2	6.86	0.00	1	666.0 ACSR
176	TL132 Dixie Tee - North Benton	Red Point	138.00	138.00	1	9.16	0.00	1	2x397.0 ACSR
177	TL132 Dixie Tee - North Benton	Red Point	138.00	138.00	2	23.80	0.00	1	2x397.0 ACSR
178	TL132 Dixie Tee - North Benton	Red Point	138.00	138.00	1	0.58	0.00	2	1272 ACSR
179	TL132 Dixie Tee - North Benton	Red Point	138.00	138.00	1	0.04	0.00	1	1590 ACSR
180	TL132 Dixie Tee - North Benton	Red Point	138.00	138.00	3	0.80	0.00	1	1272 ACSR
181	TL242 Jefferson Switching S	Lieberman (TLN194:00126)	138.00	138.00	1	0.72	0.00	1	2156.0 ACSR
182	TL242 Jefferson Switching S	Lieberman (TLN194:00126)	138.00	138.00	2	6.48	0.00	0	336.4 ACSR
183	TL292 Finney Tap	Port Robson	138.00	138.00	1	3.25	0.00	1	1590.0 ACSR
184	TL331 Caplis	McDade	138.00	138.00	2	7.87	0.00	0	
185	TL332 Wallace Lake	Finney Tap	138.00	138.00	1	2.63	0.00	2	397.5 ACSR & 1590
186	TL333 Caplis	Port Robson	138.00	138.00	1	1.29	0.00	1	1590.0 ACSR
187	TL333 Caplis	Port Robson	138.00	138.00	1	2.92	0.00	1	1590.0 ACSR
188	TL334 Haughton	McDade	138.00	138.00	2	11.30	0.00	1	4/0 ACSR
189	TL335 Haughton	Red Point	138.00	138.00	2	2.95	0.00	1	1590.0 ACSR
190	TL336 Longwood	Scottsville	138.00	138.00	1	3.88	0.00	1	1590 ACSR
191	TL339 Bean 138kV Loop		138.00	138.00	1	0.72	0.00	2	1590 ACSR
192	TL364 Port Robson	Benteler 1	138.00	138.00	1	4.10	0.00	1	1533 ACSR
193	TL365 Port Robson	Benteler 2	138.00	138.00	1	3.17	0.00	1	1533 ACSR
194	TL374 Ellerbe Road	Lucas	69.00	138.00	1	3.18	0.00	1	1272.0 ACSR
195	TL384 Mount Pleasant New Bos	New Boston	69.00	138.00	1	19.50	0.00	1	1272 ACSR
196	TL428 Flournoy	Pines Road-Hardy St	69.00	138.00	1	4.90	0.00	1	795 ACSR
197	138 kV in OK	138 kV in OK	0.00	0.00		0.00	0.00	0	
198	TL256 Patterson	Craig Junction	138.00	138.00	1	9.41	0.00	1	1272.0 ACSR
199	TL257 DeQueen	Craig Junction	138.00	138.00	1	9.98	0.00	1	1272.0 ACSR
200	TL280 Mena	Craig Junction (TLN194:0280A)	138.00	138.00	1	17.82	0.00	1	2x397.0 ACSR
201	138 kV in TX	138 kV in TX	0.00	0.00		0.00	0.00	0	
202	TL181 Northwest Texarkana	Patterson	138.00	138.00	1	0.19	0.00	1	1024.0 ACAR
203	TL181 Northwest Texarkana	Patterson	138.00	138.00	2	6.55	0.00	0	1272.0 SD
204	TL181 Northwest Texarkana	Patterson	138.00	138.00	3	0.90	0.00	0	2156.0 ACSR
205	TL198 North Mineola	Morton Tap (WCEC)	138.00	138.00	1	7.26	0.00	1	1272.0 ACSR
206	TL198 North Mineola	Morton Tap (WCEC)	138.00	138.00	1	7.26	0.00	2	1272.0&759 ACSR
207	TL200 Center	Carthage Tee	138.00	138.00	1	0.50	0.00	1	795.0 ACSR
208	TL200 Center	Carthage Tee	138.00	138.00	1	1.36	0.00	1	1272 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)
209	TL200 Center	Carthage Tee	138.00	138.00	1	17.85	0.00	1	1272 ACSR
210	TL200 Center	Carthage Tee	138.00	138.00	1	10.60	0.00	1	397 ACSR
211	TL204 Center	Logansport	138.00	138.00	1	16.38	0.00	1	755.0 ACAR
212	TL215 Turnertown-Overton-Po	Beckville-Marshall (TLN194:00215E)	138.00	138.00	1	7.22	0.00	1	2x397.0 ACSR
213	TL215 Turnertown-Overton-Po	Beckville-Marshall (TLN194:00215E)	138.00	138.00	2	5.96	0.00	1	2x397.0 ACSR
214	TL218 Mt Pleasant-Pittsburg	Henderson Manufacturing Company (TLN194:0218B)	138.00	138.00	1	9.07	0.00	1	1272.0 ACSR
215	TL220 Lone Star South	Pittsburg	138.00	138.00	1	17.67	0.00	1	1590.0 ACSR
216	TL221 Carthage	Rock Hill	69.00	138.00	1	11.40	0.00	1	1533 ACSR/TW
217	TL227 Bann	Southeast Texarkana	138.00	138.00	1	11.34	0.00	1	1272.0 ACSR
218	TL228 Bann	North New Boston	138.00	138.00	1	1.50	0.00	2	1272.0 ACSR
219	TL228 Bann	North New Boston	138.00	138.00	1	2.20	0.00	1	2x477.0 ACSR
220	TL228 Bann	North New Boston	138.00	138.00	1	14.80	0.00	1	477.0 ACSR
221	TL228 Bann	North New Boston	138.00	138.00	1	0.07	0.00	1	1272.0 ACSR
222	TL228 Bann	North New Boston	138.00	138.00	1	0.04	0.00	1	2156.0 ACSR
223	TL230 Logansport	Rock Hill (TX)	138.00	138.00	1	4.21	0.00	1	1272.0 ACSR
224	TL230 Logansport	Rock Hill (TX)	138.00	138.00	2	17.78	0.00	1	755.0 ACAR
225	TL235 Northwest Texarkana	Northeast Texarkana (Sugarhill)	138.00	138.00	1	10.34	0.00	1	1272.0 ACSR
226	TL236 North Mineola	Perdue	138.00	138.00	2	16.88	0.00	1	2x397.0 ACSR
227	TL236 North Mineola	Perdue	138.00	138.00	1	0.37	0.00	0	1272.0 ACSR
228	TL236 North Mineola	Perdue	138.00	138.00	1	2.13	0.00	0	2x397.0 ACSR
229	TL236 North Mineola	Perdue	138.00	138.00	1	0.36	0.00	1	1272.0 ACSR
230	TL236 North Mineola	Perdue	138.00	138.00	1	1.62	0.00	0	2x397.0 ACSR
231	TL236 North Mineola	Perdue	138.00	138.00	2	10.31	0.00	0	2x397.0 ACSR
232	TL237 Knox Lee	Perdue (TLN194:00237)	138.00	138.00	2	12.87	3.00	1	1272.0 ACSR
233	TL237 Knox Lee	Perdue (TLN194:00237)	0.00	0.00		0.00	0.00	0	2x397.0 ACSR
234	TL237 Knox Lee	Perdue (TLN194:00237A)	138.00	138.00	1	2.76	0.00	1	1272.0 ACSR
235	TL237 Knox Lee	Perdue (TLN194:00237A)	0.00	0.00	2	22.08	0.00	0	2x397.0 ACSR
236	TL237 Knox Lee	Perdue (TLN194:00237A)	0.00	0.00		0.00	0.00	0	397.0 ACSR
237	TL238 Diana	Perdue	138.00	138.00	2	21.85	0.00	1	2x397.0 ACSR
238	TL239 Knox Lee	North Henderson	138.00	138.00	1	7.10	0.00	1	1272.0 ACSR
239	TL239 Knox Lee	North Henderson	138.00	138.00	2	10.78	0.00	0	2x397.0 ACSR
240	TL240 Wilkes Plant	Jefferson Switching Station	138.00	138.00	2	11.10	0.00	1	1024.0 ACAR
241	TL241 AP&L-Patterson-Jeffer	Marshall-Knox Lee-Overton (TLN194:0241A)	138.00	138.00	1	11.31	0.00	1	1590 ACSR
242	TL241 AP&L-Patterson-Jeffer	Marshall-Knox Lee-Overton (TLN194:0241B)	138.00	138.00	2	0.20	0.00	1	2156.0 ACSR
243	TL241 AP&L-Patterson-Jeffer	Marshall-Knox Lee-Overton (TLN194:0241B)	138.00	138.00	1	3.14	0.00	1	1590 ACSR
244	TL241 AP&L-Patterson-Jeffer	West Atlanta w/tap to IPC (TLN194:0241D)	138.00	138.00	1	2.40	0.00	1	795 ACAR
245	TL241 AP&L-Patterson-Jeffer	Marshall-Knox Lee-Overton (TLN194:0241,C,D)	138.00	138.00	2	5.96	0.00	0	397.0 ACSR
246	TL241 AP&L-Patterson-Jeffer	West Atlanta w/tap to IPC (TLN194:0241D)	138.00	138.00	1	16.80	0.00	1	795 ACSR
247	TL241 AP&L-Patterson-Jeffer	West Atlanta w/tap to IPC (TLN194:0241D)	138.00	138.00	2	0.08	0.00	2	1272.0 ACSR
248	TL241 AP&L-Patterson-Jeffer	Marshall-Knox Lee-Overton (TLN194:0241E)	138.00	138.00	1	16.60	0.00	1	1590 ACSR
249	TL241 AP&L-Patterson-Jeffer	Marshall-Knox Lee-Overton (TLN194:00241F)	138.00	138.00	1	23.91	0.00	1	2x397.0 ACSR
250	TL241 AP&L-Patterson-Jeffer	Marshall-Knox Lee-Overton (TLN194:00241G)	138.00	138.00	2	13.54	0.00	1	2x1033.5 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)
251	TL242 Jefferson Switching S	Lieberman (TLN194:0242A)	138.00	138.00	2	19.80	0.00	1	336.4 ACSR
252	TL242 Jefferson Switching S	Lieberman (TLN194:0242A)	0.00	0.00		0.00	0.00	0	397.0 ACSR
253	TL242 Jefferson Switching S	Lieberman (TLN194:0242)	138.00	138.00	1	1.42	0.00	1	795.0 ACSR
254	TL243 Eastex Switching	Whitney (TLN194:0243C)	138.00	138.00	1	3.27	0.00	1	2x336.0 ACSR
255	TL243 Eastex Switching	Whitney (TLN194:0243B)	138.00	138.00	2	0.83	0.00	0	2x795.0 ACSR
256	TL243 Eastex Switching	Whitney (TLN194:243A1)	138.00	138.00	2	0.83	0.00	0	2x795.0 ACSR
257	TL243 Eastex Switching	Whitney (TLN194:243A1)	138.00	138.00	1	0.30	0.00	0	2x795.0 ACSR
258	TL243 Eastex Switching Stat	South Texas Eastman (TLN194:0243A2)	138.00	138.00	2	0.83	0.00	1	2x795.0 ACSR
259	TL243 Knox Lee	South Texas Eastman (TLN194:0243D)	138.00	138.00	2	6.47	0.00	1	2x336.0 ACSR
260	TL243 Knox Lee	South Texas Eastman (TLN194:0243D)	138.00	138.00	2	0.97	0.00	1	2x795.0 ACSR
261	TL243 Marshall	Pirkey (TLN194:0243E)	138.00	138.00	2	6.53	2.00	1	2x1033.5 ACSR
262	TL243 Pirkey	Whitney (TLN194:0243F)	138.00	138.00	2	15.52	0.00	1	2x1033.5 ACSR
263	TL243 Pirkey	Whitney (TLN194:0243F)	138.00	138.00	2	0.08	0.00	1	2x1272 ACSR
264	TL244 Longwood	Scottsville (TLN194:00244)	138.00	138.00	1	12.19	0.00	1	1590.0 ACSR
265	TL244 Pirkey	Scottsville (TLN194:0244A)	138.00	138.00	1	0.09	0.00	1	1272.0 ACSR
266	TL244 Pirkey	Scottsville (TLN194:0244A)	138.00	138.00	2	17.21	0.00	1	2x397.0 ACSR
267	TL244 Pirkey	Scottsville (TLN194:0244A)	138.00	138.00	2	0.88	0.00	1	2x477.0 ACSR
268	TL245 Knox Lee	South Shreveport (TLN194:00245)	138.00	138.00	1	2.69	0.00	1	666.0 ACSR
269	TL245 Knox Lee	South Shreveport (TLN194:00245)	138.00	138.00	2	10.01	0.00	0	795.0 ACSR
270	TL245 Knox Lee	South Shreveport (TLN194:00245)	138.00	138.00	1	2.21	0.00	0	795.0 ACSR
271	TL245 Rock Hill	Southwest Shreveport	138.00	138.00	2	23.31	0.00	1	397.0 ACSR
272	TL246 North New Boston	Patterson	138.00	138.00	2	5.41	0.00	1	666.0 ACSR
273	TL246 North New Boston	Wilkes	138.00	138.00	2	46.73	0.00	1	666.0 ACSR
274	TL246 North New Boston	Wilkes	138.00	138.00	2	0.15	0.00	1	795.0 ACSR
275	TL246 North New Boston	Wilkes	138.00	138.00	1	0.06	0.00	2	1272.0 ACSR
276	TL247 Wilkes Plant	Jefferson Switching Station	138.00	138.00	1	1.15	0.00	1	1033 ACAR
277	TL247 Wilkes Plant	Jefferson Switching Station	138.00	138.00	1	0.16	0.00	1	1024.0 ACAR
278	TL247 Wilkes Plant	Jefferson Switching Station	0.00	0.00	2	31.68	0.00	0	666.0 ACSR
279	TL248 Lone Star South	Wilkes Plant	138.00	138.00	1	0.12	0.00	1	2x666.0&795.0 ACS
280	TL248 Lone Star South	Wilkes Plant	138.00	138.00	2	10.87	0.00	0	2x795.0 ACSR
281	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:00249)	138.00	138.00	1	0.12	0.00	1	2x336.0&397.0 ACS
282	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:00249)	138.00	138.00	2	12.38	0.00	1	2x666.0&795.0 ACS
283	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:00249)	138.00	138.00	1	0.13	0.00	1	2x397.0 ACSR
284	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:0249A)	138.00	138.00	1	2.42	3.00	1	1272.0 ACSR
285	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:0249A)	138.00	138.00	2	11.86	0.00	0	2x336.0&397.0 ACS
286	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:0249A)	138.00	138.00		0.00	0.00	0	336.4 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)
287	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:00249A)	138.00	138.00	1	3.23	0.00	1	1272.0 ACSR
288	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:00249C)	138.00	138.00	2	9.76	0.00	0	2x336.0&397.0 ACS
289	TL249 Whitney-Pliler	Diana-Lone Star South (TLN194:00249C)	138.00	138.00		0.00	0.00	0	2x397.0 ACSR
290	TL250 Wilkes Plant	Petty	138.00	138.00	1	0.06	0.00	1	1272 ACSR
291	TL250 Wilkes Plant	Petty	138.00	138.00	1	34.01	0.00	1	2-397 ACSR
292	TL277 Eastex	Harrison Road	138.00	138.00	1	9.57	0.00	1	1272.0 ACSR
293	TL278 Diana-Spring Hill	Lake Lamond (TLN194:00278)	138.00	138.00	1	22.98	0.00	1	1590.0 ACSR
294	TL286 Pittsburg	Winnsboro	138.00	138.00	1	20.32	1.00	1	1590 ACSR
295	TL287 North Mineola	Winnsboro	138.00	138.00	1	25.05	0.00	2	1590 ACSR & 477 ACSR
296	TL287 North Mineola	Winnsboro	138.00	138.00	1	0.07	0.00	1	1590 ACSR
297	TL294 Childress-Shamrock	Gray County Line	138.00	138.00	1	4.92	0.00	1	477.0 ACSR
298	TL294 Childress-Shamrock	Gray County Line	138.00	138.00	2	51.35	0.00	1	477.0 ACSR
299	TL295 Lake Pauline	Russell	138.00	138.00	2	14.22	0.00	1	477.0 ACSR
300	TL300 Lake Pauline	West Childress	138.00	138.00	2	35.14	0.00	1	477.0 ACSR
301	TL384 Mount Pleasant	New Boston	69.00	138.00	1	19.50	0.00	1	1272 ACSR
302	TL392 West Mount Pleasant T		69.00	138.00	1	0.70	0.00	1	1272.0 ACSR
303	TL409 HILL LAKE EXTENSION		138.00	138.00	1	0.25	0.00	2	1272.0 ACSR
304	TL410 Naples Tap		69.00	138.00	1	6.40	0.00	1	1272.0 ACSR
305	TL411 Cookville Tap		69.00	138.00	1	1.93	0.00	1	1272.0 ACSR
306	115 kV in AR		0.00	0.00		0.00	0.00	0	
307	TL171 Okay	AP&L Co Interconnect (TLN194:0171A)	115.00	115.00	2	0.01	0.00	1	1272.0 AAC
308	TL171 Okay	AP&L Co Interconnect (TLN194:0171)	115.00	138.00	1	15.50	0.00	1	1591 ACSR
309	TL171 Okay	AP&L Co Interconnect (TLN194:0171A)	115.00	115.00	2	7.10	0.00	1	1272.0 ACSR
310	TL326 Okay	Patterson	115.00	138.00	1	19.31	0.00	1	1590 ACSR
311	TL326 Okay	Patterson	115.00	138.00	1	0.35	0.00	2	1590 ACSR
312	115 kV in LA	115 kV in LA	0.00	0.00		0.00	0.00	0	
313	TL357 Interconnect	Jeld-Wen	115.00	115.00		0.64	0.00	1	336.4 kCM ACSR
314	115 kV in TX	115 kV in TX	0.00	0.00		0.00	0.00	0	
315	TL296 Shamrock	Gray County Line	115.00	115.00	1	14.24	0.00	1	4/0 ACSR
316	69 kV in AR	69 kV in AR	0.00	0.00		0.00	0.00	0	
317	TL142 Abbott Tee	Waldron	69.00	69.00	1	14.21	0.00	1	477.0 ACSR
318	TL151 Dixie Tee	Belcher-Texarkana Plant (TLN194:0151C)	69.00	69.00	2	0.25	0.00	1	397.0 ACSR
319	TL151 Dixie Tee	Belcher-Texarkana Plant (TLN194:0151A)	69.00	69.00	1	0.50	0.00	1	266.8 ACSR
320	TL151 Dixie Tee	Belcher-Texarkana Plant (TLN194:0151A)	69.00	69.00	2	8.45	0.00	0	
321	TL151 Dixie Tee	Belcher-Texarkana Plant (TLN194:0151)	69.00	69.00	1	1.33	0.00	1	266.8 ACSR
322	TL151 Dixie Tee	Belcher-Texarkana Plant (TLN194:0151)	69.00	69.00	2	18.49	0.00	1	4/0 ACSR
323	TL151 Dixie Tee	Belcher-Texarkana Plant (TLN194:0151B)	69.00	69.00	1	0.05	0.00	1	266.8 ACSR
324	TL151 Dixie Tee	Belcher-Texarkana Plant (TLN194:0151D)	69.00	69.00	1	0.52	0.00	1	266.8 ACSR
325	TL152 Mena - Dequeen - Nash	Murfreesboro (TLN194:0152B)	69.00	69.00	1	2.04	0.00	1	2/0 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)
326	TL152 Mena - Dequeen - Nash	Murfreesboro (TLN194:0152D)	69.00	69.00	2	10.67	0.00	1	4/0 ACSR
327	TL152 Mena - Dequeen - Nash	Murfreesboro (TLN194:0152D)	69.00	69.00	1	0.05	0.00	1	556.5 ACSR
328	TL152 Mena - Dequeen - Nash	Narrows Dam/Tap - Murfreesboro (TLN194:0152C)	69.00	69.00	1	2.78	0.00	1	4/0 ACSR
329	TL152 Mena - Dequeen - Nash	Narrows Dam/Tap - Murfreesboro (TLN194:0152C)	69.00	69.00	2	3.77	0.00	1	4/0 ACSR
330	TL152 Mena - Dequeen - Nash	Narrows Dam/Tap - Murfreesboro (TLN194:0152C)	69.00	69.00	1	0.10	0.00	1	556.5 ACSR
331	TL152 Mena-DeQueen-Nashvill	Narrows Dame/Tap-Murfreesboro (TLN194:00152)	69.00	69.00	1	5.76	0.00	1	795.0 ACSR
332	TL152 Mena-DeQueen-Nashvill	Narrows Dame/Tap-Murfreesboro (TLN194:00152)	69.00	69.00	2	34.47	0.00	1	795 ACSR
333	TL152 Mena-DeQueen-Nashvill	Narrows Dame/Tap-Murfreesboro (TLN194:00152)	69.00	69.00	2	1.80	0.00	2	795 ACSR
334	TL152 Mena-DeQueen-Nashvill	Narrows Dame/Tap-Murfreesboro (TLN194:00152A)	69.00	69.00	1	0.13	0.00	1	795 ACSR
335	TL152 Mena-DeQueen-Nashvill	Narrows Dame/Tap-Murfreesboro (TLN194:00152A)	69.00	69.00	2	28.75	0.00	0	
336	TL153 Nashville	Okay	69.00	69.00	2	13.76	0.00	1	559.0 ACAR
337	TL153 Nashville	Okay	69.00	69.00	1	0.37	0.00	1	559.0 ACAR
338	TL154 VBI-Rogers/Loop Thru	SEFOR Project (TLN194:0154B)	69.00	69.00	1	3.07	0.00	1	336.4 ACSR
339	TL154 VBI-Rogers/Loop Thru	SEFOR Project (TLN194:0154B)	69.00	69.00	1	2.46	0.00	1	666.0 ACSR
340	TL154 VBI-Rogers/Loop Thru	SEFOR Project (TLN194:0154D)	69.00	69.00	2	1.99	0.00	1	2x397.0 ACSR
341	TL154 VBI-Rogers/Loop Thru	SEFOR Project (TLN194:0154F)	69.00	69.00	1	0.22	0.00	1	336.4 ACSR
342	TL154 VBI-Rogers/Loop Thru	SEFOR Project (TLN194:0154F)	69.00	69.00	2	3.72	0.00	1	336.4 ACSR
343	TL154 VBI-Rogers/Loop Thru	SEFOR Project (TLN194:0154H)	69.00	69.00	2	2.50	0.00	1	1272 ACSR
344	TL155 Patterson-Foreman	DeQueen/Tap-Magnolia Pump Station (TLN194:00155)	69.00	69.00	1	1.56	0.00	1	2/0 ACSR
345	TL155 Patterson-Foreman	DeQueen/Tap-Magnolia Pump Station (TLN194:00155)	69.00	69.00	2	37.36	0.00	1	4/0 ACSR
346	TL155 Patterson-Foreman	DeQueen/Tap-Magnolia Pump Station (TLN194:00155)	69.00	69.00	1	0.19	0.00	1	795 ACSR
347	TL156 PSO-Midland	State Line (TLN194:00156)	69.00	69.00	1	9.44	0.00	1	2/0 ACSR
348	TL158 Texarkana Plant - Was	12th St - Patterson/tap - Co-Oper Tire (TLN194:0158E)	69.00	69.00	1	2.80	0.00	1	2x336.0 ACSR
349	TL158 Texarkana Plant - Was	12th St - Patterson/tap - Co-Oper Tire (TLN194:0158B)	69.00	69.00	1	0.32	0.00	1	4/0 ACSR
350	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A1)	69.00	69.00	1	0.81	0.00	1	2x397.0 ACSR
351	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A1)	69.00	69.00	1	0.25	0.00	2	1590 ACSR
352	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A1)	69.00	69.00	1	0.30	0.00	1	1272 ACSR
353	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A1)	69.00	69.00	1	0.02	0.00	1	1590 ACSR
354	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A)	69.00	69.00	1	1.73	0.00	1	1272.0 ACSR
355	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A)	69.00	69.00	1	0.07	0.00	1	795 ACSR
356	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A)	69.00	69.00	1	12.50	0.00	1	2x397.0 ACSR
357	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A)	69.00	69.00	3	0.65	0.00	1	2x397.0 ACSR
358	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158A)	69.00	69.00	2	5.25	0.00	1	2x397.0 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)
359	TL158 Texarkana Plant-Washi	12th St-Patterson/tap-Co-Oper Tire (TLN194:158D)	69.00	69.00		0.00	0.00	0	1272.0 ACSR
360	TL160 Dierks	South Dierks	69.00	69.00	1	1.25	0.00	1	397.0 ACSR
361	TL160 Dierks	South Dierks	69.00	69.00	2	0.61	0.00	1	397.0 ACSR
362	TL161 Centerton	Rogers (TLN194:0161A)	69.00	69.00	1	9.90	0.00	1	1272.0 AAC
363	TL162 Midland-Huntington-RE	Booneville-Branch/Tap-Magazine-North Magazine (TLN194:0162A)	69.00	69.00	1	2.64	0.00	1	4/0 ACSR
364	TL164 Siloam Springs	Prairie Grove - Greenland (TLN194:0164A)	69.00	69.00	1	1.19	0.00	1	477.0 ACSR
365	TL164 Siloam Springs	Prairie Grove - Greenland (TLN194:0164A)	69.00	69.00	2	19.37	0.00	1	477.0 ACSR
366	TL164 Siloam Springs - Prai	Greenland (TLN194:00164)	69.00	69.00	2	8.04	0.00	1	477.0 ACSR
367	TL164 Siloam Springs - Prai	Greenland (TLN194:00164)	69.00	69.00	2	0.52	0.00	2	477.0 ACSR & 336.4 ACSR
368	TL165 Southeast Texarkana	Texarkana Plant	69.00	69.00	1	0.24	0.00	1	1272.0 ACSR
369	TL167 Mena-Murfreesboro	Dierks (TLN194:0167C)	69.00	69.00	1	2.50	0.00	1	397.0 ACSR
370	TL167 Mena-Murfreesboro	Dierks (TLN194:00167)	69.00	69.00	2	30.50	0.00	1	477.0 ACSR
371	TL167 Mena-Murfreesboro	Dierks (TLN194:00167)	69.00	69.00	1	7.67	0.00	1	477.0 ACSR
372	TL167 Mena-Murfreesboro	Dierks (TLN194:00167)	69.00	69.00	1	0.09	0.00	1	795.0 ACSR
373	TL167 Mena-Murfreesboro	Dierks (TLN194:0167B)	69.00	69.00	1	18.77	0.00	1	266.8 ACSR
374	TL168 Radial Patterson	Nekoosa - Edwards	69.00	138.00	1	5.09	0.00	1	1272.0 ACSR
375	TL169 East Rogers	North Rogers	69.00	69.00	1	1.95	0.00	1	2x397.0 ACSR
376	TL213 Texarkana Plant - Ban	De Kalb - Mt Pleasant/taps (TLN194:0213K)	69.00	69.00	1	0.53	0.00	1	1272.0 ACSR
377	TL213 Texarkana Plant - Ban	De Kalb - Mt Pleasant/taps (TLN194:0213M)	69.00	69.00	1	0.34	0.00	1	1272.0 ACSR
378	TL369 Midland	North Huntington (TLN194:00369)	69.00	161.00	2	4.76	0.00	0	1233.6 ACSR
379	TL370 Midland	Leflore County (State Line) (TLN194:00370)	69.00	161.00	2	7.00	0.00	1	4/0 ACSR
380	TL388 North Huntington	Waldron	69.00	161.00	1	18.53	0.00	1	795 ACSR
381	TL389 Greenland	VBI	69.00	161.00	1	0.04	0.00	1	1272 ACSR
382	69 kV in LA	69 kV in LA	0.00	0.00		0.00	0.00	0	
383	TL102 Hosston - Plain Deali	North Benton	69.00	69.00	1	0.99	0.00	1	477 ACSR
384	TL102 Hosston - Plain Deali	North Benton	69.00	69.00	1	26.59	0.00	1	397.0 ACSR
385	TL102 Hosston - Plain Deali	North Benton	69.00	69.00	1	0.36	0.00	1	556.5 ACSR
386	TL104 Red Point-Dogwood-Bel	Bellevue Oilfield (TLN194:00104)	69.00	69.00	1	8.80	0.00	1	4/0 ACSR
387	TL104 Red Point-Dogwood-Bel	Bellevue Oilfield (TLN194:0104A)	69.00	69.00	1	3.41	0.00	1	4/0 ACSR
388	TL104 Red Point-Dogwood-Bel	Bellevue Oilfield (TLN194:0104B)	69.00	69.00	2	2.17	0.00	1	4/0 ACSR
389	TL108 Logansport	Stanley Tap	69.00	69.00	1	7.00	0.00	1	2/0 ACSR
390	TL108 Logansport	Stanley Tap	69.00	69.00	1	2.67	0.00	1	1/0 ACSR
391	TL111 Dixie Tee (Disconnect	Texarkana Plant (TLN194:00111)	69.00	69.00	2	9.72	0.00	1	266.8 ACSR
392	TL111 Dixie Tee (Disconnect	Texarkana Plant (TLN194:0111A)	69.00	69.00	2	12.00	0.00	1	266.8 ACSR
393	TL112 Center-Powell Street-	Panola Harrsion Rural Electric Association (TLN194:0112B)	69.00	69.00	1	3.88	0.00	1	666.0 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)
394	TL112 Center-Powell Street-	Panola Harrsion Rural Electric Association (TLN194:0112B)	69.00	69.00	1	0.54	0.00	1	795 ACSR
395	TL113 Gilliam	Marshall (TLN194:0113B)	69.00	69.00	2	3.57	0.00	1	266.8 ACSR
396	TL113 Gilliam	Marshall (TLN194:0113B)	69.00	69.00	2	6.60	0.00	1	4/0 ACSR
397	TL114 Shreveport 69KV Loop	(TLN194:00114)	69.00	69.00	1	1.77	0.00	1	2x397.0 ACSR
398	TL114 Shreveport 69KV Loop	(TLN194:0114A)	69.00	69.00	1	2.20	0.00	1	1272.0 ACSR
399	TL114 Shreveport 69KV Loop	(TLN194:0114B)	69.00	138.00	1	2.55	0.00	1	1272.0 ACSR
400	TL114 Shreveport 69KV Loop	(TLN194:0114D)	69.00	69.00	1	0.00	0.00	2	795 ACSR
401	TL114 Shreveport 69KV Loop	(TLN194:0114D)	69.00	69.00	1	0.33	0.00	1	666.6 ACSR
402	TL114 Shreveport 69KV Loop	(TLN194:0114D)	69.00	69.00	1	0.00	0.00	2	666.6 ACSR
403	TL114 Shreveport 69KV Loop	(TLN194:0114J)	69.00	69.00	1	0.26	0.00	1	666.6 ACSR
404	TL114 Shreveport 69KV Loop	(TLN194:0114F)	69.00	69.00	1	0.89	1.00	1	666.0 ACSR
405	TL114 Shreveport 69KV Loop	(TLN194:0114G)	69.00	69.00	1	1.81	0.00	1	2x397.5 ACSR
406	TL114 Shreveport 69KV Loop	(TLN194:0114G)	69.00	69.00	1	0.56	0.00	2	666.6 ACSR
407	TL114 Shreveport 69KV Loop	(TLN194:0114H)	69.00	138.00	1	3.02	0.00	1	1233.6 ACSR
408	TL114 Shreveport 69KV Loop	(TLN194:0114K)	69.00	69.00	1	0.15	0.00	1	666.6 ACSR
409	TL114 Shreveport 69KV Loop	(TLN194:0114L)	69.00	69.00	1	1.17	0.00	1	666.0 ACSR
410	TL114 Shreveport 69KV Loop	(TLN194:0114M)	69.00	138.00	1	1.64	0.00	1	1233.6 ACSR
411	TL115 Bossier City (AH - Ft Humbug) 69KV Loop	(TLN194:00115)	69.00	69.00	4	0.60	0.00	1	2500.0 CU
412	TL115 Bossier City (AH - Ft Humbug) 69KV Loop	(TLN194:00115)	69.00	69.00	1	0.50	0.00	1	1272.0 ACSR
413	TL115 Bossier City (AH - Ft Humbug) 69KV Loop	(TLN194:00115)	69.00	69.00	1	1.50	0.00	1	2x397.5 ACSR
414	TL115 Bossier City (AH-Ft H	(TLN194:0115A)	69.00	69.00	1	1.70	0.00	1	2x397.0 ACSR
415	TL116 North Market-Brownlee	Minden Road (TLN194:00116)	69.00	69.00	1	4.37	0.00	1	666.6 ACSR
416	TL117 Leiberman - Superior	Vivian - Hosston	69.00	69.00	1	6.65	0.00	1	336.4 ACSR
417	TL117 Leiberman - Superior	Vivian - Hosston	69.00	69.00	1	3.80	0.00	1	4/0 ACSR
418	TL118 Ellerbe Road - Finney	Wallace lake (TLN194:0118B)	69.00	69.00	1	5.18	0.00	1	397.5 ACSR
419	TL120 Summer Grove-Flournoy	REA & Bingham Pump Plant (TLN194:0120A)	69.00	69.00	1	6.70	0.00	1	397.0 ACSR
420	TL120 Summer Grove-Flournoy	REA & Bingham Pump Plant (TLN194:0120A)	69.00	69.00	1	2.55	0.00	1	477.0 ACSR
421	TL120 Summer Grove-Flournoy	REA & Bingham Pump Plant (TLN194:0120B)	69.00	69.00	1	9.47	0.00	1	4/0 ACSR
422	TL121 Leiberman-Blanchard	North Market (TLN194:00121)	69.00	69.00	1	6.23	0.00	1	666.6 ACSR
423	TL121 Leiberman-Blanchard	North Market (TLN194:00121)	69.00	69.00	2	0.60	0.00	1	666.6 ACSR
424	TL121 Leiberman-Blanchard	North Market (TLN194:00121)	69.00	69.00	3	0.07	0.00	1	666.6 ACSR
425	TL121 Leiberman-Blanchard	North Market (TLN194:0121A)	69.00	69.00	1	11.75	0.00	1	477.0 ACSR

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426	TL121 Leiberman-Blanchard	North Market (TLN194:0121A)	69.00	69.00	1	1.06	0.00	1	959.6 ACSR
427	TL124 Red Point-Calumet-JD	Texaco Oil-Getty Oil (TLN194:00124)	69.00	69.00	1	4.29	0.00	1	266.8 ACSR
428	TL124 Red Point-Calumet-JD	Texaco Oil-Getty Oil (TLN194:0124A)	69.00	69.00	1	4.78	0.00	1	266.8 ACSR
429	TL124 Red Point-Calumet-JD	Texaco Oil-Getty Oil (TLN194:0124B)	69.00	69.00	1	0.37	0.00	1	2/0 ACSR
430	TL125 Flournoy-Pines Road	Hardy St	69.00	69.00	1	5.29	0.00	1	397.5 ACSR
431	TL125 Flournoy-Pines Road	Hardy St	69.00	69.00	2	0.40	0.00	1	397.5 ACSR
432	TL347 E Leesville	Hicks	69.00	69.00	1	16.38	0.00	1	336.4 kCM ACSR
433	TL348 E Leesville	N Leesville	69.00	69.00	1	3.20	0.00	1	336.4 kCM ACSR
434	TL349 Many	Belmont	69.00	69.00	1	3.80	0.00	1	795 kCM ACSR
435	TL349 Many	Belmont	69.00	69.00	2	6.66	0.00	2	795 kCM ACSR
436	TL350 Many	Negreet	69.00	69.00	2	3.97	0.00	1	795 kCM ACSR
437	TL350 Many	Negreet	69.00	69.00	1	8.66	0.00	1	795 kCM ACSR
438	TL351 Noble	Mount Zion	69.00	69.00	1	11.25	0.00	1	795 kCM ACSR
439	TL351 Noble	Mount Zion	69.00	69.00	2	0.87	0.00	1	795 kCM ACSR
440	TL352 Hornbeck	N Leesville	69.00	69.00	1	13.00	0.00	1	336.4 kCM ACSR
441	TL353 Belmont	Marthaville	69.00	69.00	2	1.84	0.00	1	336.4 kCM ACSR
442	TL354 Bayou-Pierre	Kingston	69.00	69.00	1	13.60	0.00	1	336.4 ACSR
443	TL355 Montgomery	Verda	13.80	69.00	1	3.20	0.00	1	336.4 kCM ACSR
444	TL358 Marthaville	Robeline	69.00	69.00	1	8.26	0.00	1	336.4 ACSR
445	TL376 Brooks Street	Edwards Street	69.00	138.00	1	0.85	0.00	1	1233.6 ACSR/TW
446	TL377 Leaside Way	Summer Grove	69.00	69.00	1	1.68	0.00	1	477.0 ACSR
447	TL405 Brownlee Road	North Market	69.00	138.00	1	0.21	0.00	2	1233.6 ACSR
448	TL405 Brownlee Road	North Market	69.00	138.00	1	4.49	0.00	1	1233.6 ACSR
449	TL408 Broadmoor	Fort Humbug	69.00	138.00	1	1.36	1.00	1	1233.6 ACSR/TW
450	69 kV in TX	69 kV in TX	0.00	0.00		0.00	0.00	0	
451	66-027 Clarksville	Greggton w/taps to MidVally	69.00	69.00	1	8.49	0.00	1	2/0 ACSR
452	66-027 Clarksville	& Texoma	0.00	0.00		0.00	0.00	0	755.0 ACAR
453	66-028 Clarksville	Sabine w/tap to Service	69.00	69.00	1	1.85	0.00	1	2/0 ACSR
454	66-028 Clarksville	Pipeline	0.00	0.00	2	7.11	0.00	0	397.0 ACSR
455	66-029 Clarksville	Perdue	69.00	69.00	1	7.29	0.00	1	477.0 ACSR
456	66-030 Clarksville	Perdue	69.00	69.00	1	6.32	0.00	1	2x397.0 ACSR
457	66-030 Clarksville	Perdue	0.00	0.00	2	0.65	0.00	0	
458	66-049 Evenside	Poynter	69.00	69.00	1	3.66	0.00	1	477.0 ACSR
459	66-050 Evenside	Sawmill w/taps to Sohio	69.00	69.00	1	14.89	0.00	1	2/0 ACSR
460	66-050 Evenside	Pump & North Laneville	0.00	0.00		0.00	0.00	0	266.8 ACSR
461	66-056 Flournoy	Woodlawn w/taps to Karnack	69.00	69.00	1	33.22	0.00	1	# 2 CU (7 Strand)
462	66-057 Gilmer	Perdue	69.00	69.00	1	11.44	0.00	1	397.0 ACSR
463	66-058 Gilmer	Pittsburg w/tap to	69.00	69.00	1	24.47	0.00	1	2/0 ACSR
464	66-058 Gilmer	Pittsburg Steel	0.00	0.00		0.00	0.00	0	336.4 ACSR
465	66-059 Grand Saline	Mineola	69.00	69.00	1	6.81	7.00	1	4/0 ACSR
466	66-064 Greggton	Lake Lamond	69.00	69.00	1	2.66	0.00	1	1272 ACSR
467	66-068 Hawkins	Mineola	69.00	69.00	1	1.24	0.00	1	477.0 ACSR
468	66-068 Hawkins	Mineola	0.00	0.00	2	17.42	0.00	1	477.0 ACSR
469	66-069 Hawkins	Perdue	69.00	69.00	1	10.90	0.00	1	477.0 ACSR
470	66-073 Hughes Springs	Linden	69.00	69.00	1	0.25	0.00	1	397.0 ACSR
471	66-073 Hughes Springs	Linden	0.00	0.00	2	15.45	0.00	0	

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472	66-077 Kilgore	Overton	69.00	69.00	1	4.72	0.00	1	336.4 ACSR
473	66-077 Kilgore	Overton	0.00	0.00	2	7.70	0.00	0	477.0 ACSR
474	66-078 Kilgore	Sabine	69.00	69.00	1	3.49	1.00	1	4/0 ACSR
475	66-078 Kilgore	Sabine	0.00	0.00	2	2.12	0.00	0	
476	66-080 Knox Lee	Southeast Longview	69.00	69.00	1	5.87	0.00	1	2x477.0 ACSR
477	66-080 Knox Lee	Southeast Longview	0.00	0.00		0.00	0.00	0	2x795.0 ACSR
478	66-081 Lake Lamond	Longview	69.00	69.00	1	3.14	0.00	1	755.0 ACAR
479	66-082 Lake Lamond	Southeast Longview w/tap to	69.00	69.00	1	8.66	0.00	1	2x336.0&397.0 ACS
480	66-082 Lake Lamond	Big Three	0.00	0.00		0.00	0.00	0	397.0 ACSR
481	66-083 Lake Lamond	Longview Heights	69.00	69.00	1	7.16	3.00	1	477.0 ACSR
482	66-083 Lake Lamond	Longview Heights	0.00	0.00		0.00	0.00	0	795.0 ACSR
483	66-088 Longview	Whitney	69.00	69.00	1	2.59	0.00	1	2x336.0 ACSR
484	66-088 Longview	Whitney	0.00	0.00		0.00	0.00	0	2x397.0 ACSR
485	66-094 Marshall	North Marshall	69.00	69.00	2	3.49	0.00	1	1272.0 ACSR
486	66-128 Winfield	Winnsboro w/taps to Mount	69.00	69.00	1	18.69	3.00	1	2/0 ACSR
487	66-128 Winfield	Vernon & Texoma	0.00	0.00	2	12.90	0.00	0	336.4 ACSR
488	66-128 Winfield	Vernon & Texoma	0.00	0.00		0.00	0.00	0	477.0 ACSR
489	66-203 Mount Pleasant	Petty	69.00	69.00	1	2.06	0.00	1	755.0 ACAR
490	66-217 Pittsburg	Winnsboro w/tap to Ferndale	69.00	69.00	1	23.17	1.00	1	266.8 ACSR
491	66-217 Pittsburg	Lake	0.00	0.00		0.00	0.00	0	477.0 ACSR
492	66-330 Carthage	Murvaul REC	69.00	69.00	1	2.62	1.00	1	336.4 ACSR
493	66-330 Carthage	Murvaul REC	0.00	0.00		0.00	0.00	0	397.0 ACSR
494	66-633 Marshall 138	Marshall 69	69.00	69.00	1	0.11	0.00	1	2x1272.0 AAC
495	66-803 (21176) Vernon Main	WFEC Russell (Interconnect)	69.00	69.00	2	4.32	0.00	1	477.0 ACSR
496	66-804 (21200) Shamrock	SPS Magic City	69.00	69.00	1	0.85	0.00	1	2/0 ACSR
497	66-804 (21200) Shamrock	(Interconnect)	0.00	0.00	2	16.92	0.00	0	
498	Plant	Plant	0.00	0.00		0.00	0.00	0	
499	TL118A (Radial) Finney Tap		69.00	69.00	1	0.40	0.00	1	2/0 ACSR
500	TL151 Dixie Tee	Belcher-Texarkana Plant (TLN194:0151D)	69.00	69.00	1	1.81	0.00	1	266.8 ACSR
501	TL201 Atlanta	Hughes Springs (TLN194:00201)	69.00	69.00	1	1.40	0.00	1	397.0 ACSR
502	TL201 Atlanta	Hughes Springs (TLN194:00201)	69.00	69.00	1	0.85	0.00	1	556.5 ACSR
503	TL201 Atlanta	Hughes Springs (TLN194:00201)	69.00	69.00	2	11.70	0.00	1	397.0 ACSR
504	TL202 Beckville - Cathage	Center (TLN194:00202)	69.00	69.00	2	6.60	0.00	1	397.0 ACSR
505	TL202 Beckville - Cathage	Center (TLN194:0202A)	69.00	69.00	2	1.55	0.00	1	397.0 ACSR
506	TL202 Beckville - Cathage	Center (TLN194:0202A)	69.00	69.00	1	0.80	0.00	1	397.0 ACSR
507	TL203 Bloomburg	Atlanta	69.00	69.00	2	6.75	0.00	1	397.0 ACSR
508	TL203 Bloomburg	Atlanta	69.00	69.00	1	1.00	0.00	1	397.0 ACSR
509	TL205 Gilliam - Marshall With Tap	Karnack Plant (TLN194:0205A)	69.00	69.00	1	12.75	0.00	1	1272 ACSR
510	TL205 Gilliam - Marshall With Tap	Karnack Plant (TLN194:0205B)	69.00	69.00	1	0.03	0.00	1	795 ACSR
511	TL205 Gilliam - Marshall With Tap	Karnack Plant (TLN194:0205B)	69.00	69.00	2	18.27	0.00	1	267 ACSR
512	TL208 Gladewater - Greggton - Lake Lamond	Longview Heights - Marshall (TLN194:0208E)	0.00	0.00	1	2.87	0.00	1	2/0 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)
513	TL208 Gladewater - Greggton - Lake Lamond	Longview Heights - Marshall (TLN194:0208E)	0.00	0.00		0.00	0.00	0	336.4 ACSR
514	TL208 Gladewater - Greggton - Lake Lamond	Longview Heights - Marshall (TLN194:0208E)	0.00	0.00		0.00	0.00	0	4/0 ACSR
515	TL208 Longview Heights	Whitney	69.00	69.00	1	4.18	0.00	1	666.0 ACSR
516	TL208 Longview Heights	Marshall 69	69.00	138.00	1	0.04	0.00	1	1590 ACSR
517	TL209 Daingerfield	Mount Pleasant	69.00	69.00	1	1.44	0.00	1	397.0 ACSR
518	TL209 Daingerfield	Mount Pleasant	0.00	0.00	2	1.30	0.00	1	1272 ACSR
519	TL209 Daingerfield	Mount Pleasant	0.00	0.00	2	14.25	0.00	1	397.0 ACSR
520	TL210 Longview - Whitney	Kilgore - Overton (TLN194:0210A)	69.00	69.00	1	8.94	1.00	1	336.4 ACSR
521	TL210 Longview - Whitney	Kilgore - Overton (TLN194:0210A)	69.00	69.00	2	7.40	0.00	1	336.4 ACSR
522	TL211 Mineola	Gladewater/tap - Pump Stati	69.00	69.00	1	0.24	0.00	1	477.0 ACSR
523	TL212 Mt Pleasant - Mineola	Magnolia Pump Station, Mt Vernon, & Petty (TLN194:0212G)	69.00	69.00	1	1.55	0.00	1	1272.0 AAC
524	TL212 Mt Pleasant - Mineola/Taps	Magnolia Pump Station, Mt Vernon, & Petty (TLN194:0212A)	69.00	69.00	1	2.29	0.67	1	556.5 ACSR
525	TL212 Mt Pleasant - Mineola/Taps	Magnolia Pump Station, Mt Vernon, & Petty (TLN194:0212F)	69.00	69.00		0.20	0.00	1	477 ACSR
526	TL212 Mt Pleasant - Mineola/Taps	Magnolia Pump Station, Mt Vernon, & Petty (TLN194:0212F)	69.00	69.00		0.60	0.00	1	556 ACSR
527	TL212 Mt Pleasant - Mineola/Taps	Magnolia Pump Station, Mt Vernon, & Petty (TLN194:0212J)	69.00	69.00	1	0.55	0.00	1	477.0 ACSR
528	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:00213)	69.00	69.00	1	8.50	0.00	1	397.0 ACSR
529	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:0213H)	69.00	69.00	1	0.37	0.00	1	477 ACSR
530	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:00213)	69.00	69.00	1	7.14	0.00	1	1272 ACSR
531	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:0213E)	69.00	69.00	1	1.07	0.00	1	2/0 ACSR
532	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:0213G)	69.00	69.00	1	1.30	0.00	1	666.0 ACSR
533	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:0213M)	69.00	69.00	1	2.70	0.00	1	1272.0 ACSR
534	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:0213N)	69.00	69.00	1	2.40	0.00	1	2x397.0 ACSR
535	TL213 Texarkana Plant	Bann-De Kalb-Mt Pleasant (TLN194:0213K)	69.00	69.00	1	0.54	0.00	1	1272 ACSR
536	TL214 Mineola - Grand Salin	Westwood - Quitman	69.00	69.00	1	20.16	0.00	1	336.4 ACSR
537	TL214 Mineola - Grand Salin	Westwood - Quitman	69.00	69.00	1	0.05	0.00	1	556 ACSR
538	TL214 Mineola - Grand Salin	Westwood - Quitman	69.00	69.00	1	0.35	0.00	1	397.0 ACSR
539	TL214 Mineola - Grand Salin	Westwood - Quitman	69.00	69.00	1	4.10	0.00	0	795.0 ACSR
540	TL215 Turnertown-Overton-Poynter	Beckville-Marshall (215)	69.00	69.00	2	16.62	0.00	1	4/0 ACSR
541	TL215 Turnertown-Overton-Poynter	Beckville-Marshall (215)	69.00	69.00	1	6.08	0.00	1	4/0 ACSR
542	TL215 Turnertown-Overton-Poynter	Beckville-Marshall (215)	69.00	69.00	1	0.03	0.00	1	397.0 ACSR
543	TL215 Turnertown-Overton-Poynter	Beckville-Marshall (215A)	69.00	69.00	2	4.10	0.00	1	666.0 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)
544	TL215 Turnertown-Overton-Poynter	Beckville-Marshall (TLN194:0215C)	69.00	69.00	1	15.50	0.00	1	1272.0 ACSR
545	TL215 Turnertown-Overton-Poynter	Beckville-Marshall (TLN194:0215C)	69.00	69.00	2	0.50	0.00	1	1272.0 ACSR
546	TL215 Turnertown-Overton-Poynter	Beckville-Marshall (TLN194:0215C)	69.00	69.00	1	0.32	0.00	2	1272.0 ACSR & 2x397 ACSR
547	TL215 Turnertown-Overton-Poynter	Beckville-Marshall (TLN194:0215D)	69.00	138.00	1	2.72	0.00	1	1272 ACSR
548	TL215 Turnertown-Overton-Poynter	Beckville-Marshall (TLN194:0215D)	69.00	138.00	1	0.63	0.00	2	1272 ACSR
549	TL215 Turnertown-Overton-Poynter	Beckville-Marshall (TLN194:0215F)	69.00	69.00	1	6.02	0.00	1	2/0 ACSR
550	TL215 Turnertown-Overton-Poynter	Beckville-Marshall (TLN194:0215F)	69.00	69.00	1	0.00	2.00	1	2/0 ACSR
551	TL216 Hughes Springs	Lone Star Steel (TLN194:00216)	69.00	69.00	1	0.12	0.00	1	1272 ACSR
552	TL216 Hughes Springs	Lone Star Steel (TLN194:0216A)	69.00	69.00	1	8.23	0.00	1	1272 ACSR
553	TL216 Hughes Springs	Lone Star Steel (TLN194:0216B)	69.00	69.00	1	6.88	0.00	1	1272 ACSR
554	TL216 Hughes Springs	Lone Star Steel (TLN194:0216C)	69.00	69.00	1	1.04	1.00	1	397.5 ACSR
555	TL216 Hughes Springs	Lone Star Steel (TLN194:0216C)	69.00	69.00	1	0.80	1.00	2	1590&337 ACSR
556	TL216 Hughes Springs	Lone Star Steel (TLN194:0216D)	69.00	69.00	1	2.21	0.00	1	1272 ACSR
557	TL219 Southeast Longview	Whitney w/tap to Letoureau	69.00	69.00	1	4.35	0.00	1	1024.0 ACAR
558	TL219 Southeast Longview	Whitney w/tap to Letoureau	0.00	0.00		0.00	0.00	0	2/0 ACSR
559	TL219 Southeast Longview	Whitney w/tap to Letoureau	0.00	0.00		0.00	0.00	0	2x795.0 ACSR
560	TL223 Taylor Street	Bann	69.00	69.00	1	9.50	0.00	1	666.0 ACSR
561	TL232 Bloomburg	Texarkana Tap - IPC	69.00	69.00	1	1.85	0.00	1	266.8 ACSR
562	TL290 Daingerfield	Hughes Springs	69.00	69.00	1	6.08	0.00	1	1272 ACSR
563	TL293 Vernon	Red River (Interconnect PSO)	69.00	69.00	1	7.53	0.00	1	556 ACSR
564	TL297 Clarendon	Jericho	69.00	69.00	1	6.22	0.00	1	336.4 ACSR
565	TL297 Clarendon	Jericho	0.00	0.00	1	12.50	0.00	1	477 ACSR
566	TL301 West Childress	Estelline	69.00	69.00	1	17.27	0.00	1	T2 477 ACSR
567	TL301A (Radial) Carey Ext		69.00	69.00	1	0.01	0.00	1	T2 477 ACSR
568	TL302 Vernon Main St	North Vernon	69.00	69.00	1	0.02	0.00	1	477.0 ACSR
569	TL371 Longview Heights	Hallsville	69.00	138.00	1	6.54	0.00	1	954 ACSR
570	TL372 Hallsville	Marshall	69.00	138.00	1	11.15	0.00	1	954 ACSR
571	TL373 Evenside	Northwest Henderson	69.00	138.00	1	6.40	0.00	1	1272 ACSR
572	TL375 Marshall	Rockhill	69.00	138.00	1	2.25	0.00	1	1272.0 ACSR
573	TL378 Mount Pleasant	West Mount Pleasant	69.00	138.00	1	3.04	0.00	1	1533.3 ACSR
574	TL379 Blocker Tap		69.00	138.00	1	0.13	0.00	1	397 ACSR
575	TL381 Clarendon	Memphis	69.00	69.00	1	14.51	0.00	1	T2 477 ACSR
576	TL382 Memphis	Estelline	69.00	69.00	1	14.20	0.00	1	477 ACSR
577	TL384 Mount Pleasant	New Boston	69.00	138.00	1	33.30	0.00	1	1272.0 ACSR
578	TL384 Mount Pleasant	New Boston	69.00	138.00	1	13.50	0.00	1	1233.6 ACSR/TW
579	TL387 Bann	Thirty Ninth Street	69.00	138.00	1	8.86	0.00	1	1272.0 ACSR
580	TL390 Pilgrims Pride	Winfield	69.00	138.00	1	8.07	0.00	1	1272.0 ACSR
581	TL396 Childress Amoco Tap		69.00	69.00	1	1.58	0.00	1	477 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)
582	TL421 Wickes REC Tap	Wickes (SWAEC)	69.00	69.00	1	0.01	0.00	1	795 ACSR
583	TL422 Quitman	Quitman (WCEC)	69.00	69.00	1	0.18	0.00	1	556 ACSR
584	TL445 Clarendon (GEC) Ext		69.00	69.00	1	0.02	0.00	1	T2 477 ACSR
585	Line Costs and expenses are	not available by individual							
586	transmission line.	Total shown in Column j-p							
587					TOTAL	4,022.41	52.67	546	
36	TOTAL								

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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	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			
	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			
	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			
	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			
	Land (j)	Construction Costs (k)	Total Costs (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
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585	112,247,004	1,480,074,545	1,592,321,549	65,311	21,863,868		21,929,179
586							
587	112,247,004.00	1,480,074,545.00	1,592,321,549.00	65,311.00	21,863,868.00	0.00	21,929,179.00
36							

Name of Respondent: SWEPCO	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	TL301A (Radial) Carey Ext		0.01	1	1	1	1	T2 477	ACSR		69
2	TL445 Clarendon (GEC) Ext		0	1	1	1	1	T2 477	ACSR		69
44	TOTAL		0		2	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		270,593	131,968		402,561	
2		463,865	69,313		533,178	
44		734,458	201,281		935,739	

Name of Respondent: SWEPCO	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	ASHDOWN 69/12 - AR	Distribution		69.00	12.47	0.00	21.20	2	0
2	BLOOMBURG - AR	Transmission		69.00	12.47	0.00	2.00	1	0
3	BONANZA - AR	Distribution		34.50	12.47	0.00	10.00	4	0
4	BONANZA - AR	Distribution		34.50	0.00	0.00	0.00	0	0
5	BONANZA - AR	Distribution		161.00	34.50	0.00	12.00	1	0
6	BOONEVILLE - AR	Distribution		69.00	12.47	0.00	12.00	1	0
7	BOONEVILLE - AR	Distribution		69.00	12.47	0.00	12.00	1	0
8	CENTERTON - AR	Transmission		161.00	12.47	0.00	12.00	1	0
9	CHAMBERS SPRING - AR	Transmission		345.00	161.00	13.80	405.00	1	0
10	DEQUEEN - AR	Transmission		12.00	0.00	0.00	0.00	0	0
11	DEQUEEN - AR	Transmission		69.00	34.50	0.00	7.50	1	0
12	DEQUEEN - AR	Distribution		69.00	0.00	0.00	0.00	0	0
13	DEQUEEN - AR	Distribution		69.00	0.00	0.00	0.00	0	0
14	DEQUEEN - AR	Distribution		138.00	70.50	13.09	78.00	1	0
15	DEQUEEN - AR	Distribution		69.00	12.47	0.00	40.00	2	0
16	DEQUEEN - AR	Distribution		138.00	72.60	11.98	80.00	1	0
17	DIERKS - AR	Transmission		69.00	12.47	0.00	10.00	1	0
18	DIERKS - AR	Transmission		7.62	0.00	0.00	0.00	0	0
19	DIERKS - AR	Transmission		69.00	12.47	0.00	5.60	1	0
20	DIXIELAND - AR	Transmission		69.00	12.47	0.00	32.00	2	0
21	DIXIELAND - AR	Distribution		161.00	13.09	0.00	25.00	0	1
22	DYESS - AR	Transmission		69.00	12.47	0.00	15.00	2	0
23	DYESS - AR	Distribution		161.00	69.00	13.09	624.00	8	0
24	DYESS - AR	Distribution		161.00	69.00	7.62	80.00	1	0
25	EAST CENTERTON - AR	Distribution		69.00	0.00	0.00	0.00	0	0
26	EAST CENTERTON - AR	Distribution		161.00	69.00	12.47	156.00	2	0
27	EAST ROGERS - AR	Distribution		161.00	0.00	0.00	0.00	0	0
28	EAST ROGERS - AR	Distribution		161.00	69.00	13.90	80.00	1	0
29	EAST ROGERS - AR	Distribution		69.00	0.00	0.00	0.00	0	0
30	FARMINGTON - AR	Transmission		161.00	12.47	0.00	12.00	1	0
31	FAYETTEVILLE (SW) - AR	Transmission		12.00	0.00	0.00	0.00	0	0
32	FAYETTEVILLE (SW) - AR	Transmission		161.00	12.47	0.00	48.00	2	0
33	FLINT CREEK SUB - AR	Transmission		345.00	161.00	13.80	240.00	1	0
34	FLINT CREEK SUB - AR	Transmission		345.00	161.00	34.50	405.00	1	0
35	FLINT CREEK SUB - AR	Distribution		345.00	161.00	13.80	240.00	0	1
36	FOREMAN - AR	Distribution		69.00	12.47	0.00	8.40	2	0
37	FOREMAN-MAGNOLIA - AR	Distribution		69.00	2.40	0.00	3.75	1	0
38	GREENLAND - AR	Distribution		69.00	12.47	0.00	15.00	2	0
39	GREENWOOD - AR	Distribution		34.50	13.20	0.00	5.00	1	0
40	GREGG STREET - AR	Distribution		161.00	12.47	0.00	24.00	1	0
41	HUNTINGTON - AR	Distribution		69.00	34.50	0.00	10.10	1	0
42	HUNTINGTON - AR	Distribution		69.00	13.09	4.16	7.50	1	0
43	HYLAND - AR	Distribution		12.00	0.00	0.00	0.00	0	0
44	HYLAND - AR	Distribution		161.00	12.47	0.00	20.00	1	0
45	LOWELL (SEP) - AR	Distribution		161.00	12.47	0.00	30.00	2	0
46	MENA - AR	Distribution		69.00	0.00	0.00	0.00	0	0
47	MENA - AR	Distribution		12.00	0.00	0.00	0.00	0	0
48	MENA - AR	Distribution		69.00	12.47	0.00	26.88	2	0
49	MENA - AR	Distribution		69.00	34.50	0.00	10.00	1	0
50	MENA - AR	Distribution		69.00	0.00	0.00	0.00	0	0
51	MENA - AR	Distribution		138.00	72.60	13.80	56.00	1	0
52	MENA - AR	Transmission		69.00	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)
53	MIDLAND (SW) - AR	Distribution		69.00	12.47	0.00	7.50	1	0
54	NASHVILLE 69KV - AR	Distribution		69.00	36.00	0.00	2.50	1	0
55	NASHVILLE 69KV - AR	Distribution		12.47	0.00	0.00	0.00	0	0
56	NASHVILLE 69KV - AR	Transmission		69.00	0.00	0.00	0.00	0	0
57	NASHVILLE 69KV - AR	Transmission		69.00	36.29	0.00	5.00	2	0
58	NASHVILLE 69KV - AR	Transmission		69.00	12.47	0.00	7.50	1	0
59	NORTH HUNTINGTON - AR	Distribution		161.00	69.00	0.00	50.00	1	0
60	NORTH HUNTINGTON - AR	Distribution		69.00	0.00	0.00	0.00	0	0
61	NORTH HUNTINGTON - AR	Transmission		161.00	69.00	12.00	50.00	1	0
62	NORTH ROGERS - AR	Transmission		12.00	0.00	0.00	0.00	0	0
63	NORTH ROGERS - AR	Transmission		69.00	12.47	0.00	40.00	2	0
64	OKAY - AR	Transmission		138.00	70.50	13.09	54.00	1	0
65	OKAY - AR	Transmission		69.00	34.50	0.00	5.00	1	0
66	OKAY - AR	Transmission		69.00	12.47	0.00	2.00	1	0
67	OSBURN - AR	Distribution		161.00	13.09	0.00	24.00	1	0
68	OSBURN - AR	Distribution		12.47	0.00	0.00	0.00	0	0
69	PATTERSON - AR	Distribution		138.00	0.00	0.00	0.00	0	0
70	PATTERSON - AR	Distribution		138.00	70.50	13.09	910.00	9	0
71	PLEASANT HILL - AR	Transmission		69.00	13.09	0.00	5.00	1	0
72	PRAIRIE GROVE - AR	Transmission		69.00	13.09	0.00	15.00	1	0
73	REEVES ROAD - AR	Transmission		161.00	13.09	0.00	7.50	1	0
74	REEVES ROAD - AR	Transmission		161.00	36.20	0.00	20.00	0	1
75	REEVES ROAD - AR	Transmission		161.00	34.50	0.00	12.00	1	0
76	REEVES ROAD - AR	Transmission		161.00	13.09	0.00	9.38	0	1
77	ROGERS - AR	Transmission		161.00	12.47	0.00	48.00	2	0
78	ROGERS - AR	Transmission		12.00	0.00	0.00	0.00	0	0
79	SHIPE ROAD - AR	Transmission		345.00	161.00	13.80	405.00	1	0
80	SILOAM SPRINGS 161KV - AR	Transmission		161.00	69.00	13.20	80.00	1	0
81	SILOAM SPRINGS 161KV - AR	Transmission		69.00	0.00	0.00	0.00	0	0
82	SOUTH DIERKS - AR	Distribution		138.00	72.60	13.20	50.00	1	0
83	SOUTH FAYETTEVILLE - AR	Distribution		161.00	12.47	0.00	22.40	1	0
84	SOUTH FAYETTEVILLE - AR	Distribution		161.00	69.00	13.80	80.00	1	0
85	SOUTH FAYETTEVILLE - AR	Transmission		12.00	0.00	0.00	0.00	0	0
86	SOUTH FAYETTEVILLE - AR	Distribution		161.00	12.47	0.00	24.00	1	0
87	SOUTH FAYETTEVILLE - AR	Distribution		161.00	0.00	0.00	0.00	0	0
88	SOUTH FAYETTEVILLE - AR	Distribution		69.00	0.00	0.00	0.00	0	0
89	SOUTH NASHVILLE - AR	Distribution		138.00	12.47	0.00	24.00	2	0
90	SOUTH NASHVILLE - AR	Distribution		69.00	0.00	0.00	0.00	0	0
91	SOUTH SPRINGDALE - AR	Transmission		161.00	12.47	0.00	22.40	1	0
92	SOUTH SPRINGDALE - AR	Transmission		161.00	12.50	0.00	20.00	1	0
93	SOUTHEAST FAYETTEVILLE - AR	Distribution		161.00	12.50	0.00	20.00	1	0
94	SOUTHEAST TEXARKANA - AR	Distribution		138.00	72.60	13.20	80.00	1	0
95	SPRINGDALE - AR	Distribution		69.00	12.47	0.00	48.00	2	0
96	SPRINGDALE - AR	Distribution		12.00	0.00	0.00	0.00	0	0
97	SUGAR HILL (SW) - AR	Distribution		138.00	72.60	12.47	80.00	1	0
98	SUGAR HILL (SW) - AR	Distribution		138.00	12.47	0.00	12.00	1	0
99	TEXARKANA PLANT - AR	Distribution		69.00	12.47	0.00	40.00	2	0
100	TONTITOWN - AR	Transmission		345.00	161.00	13.80	675.00	0	1
101	TONTITOWN - AR	Transmission		161.00	0.00	0.00	0.00	0	0
102	TONTITOWN - AR	Transmission		345.00	161.00	13.80	405.00	1	0
103	TONTITOWN - AR	Transmission		161.00	0.00	0.00	0.00	0	0
104	TURK - AR	Transmission		345.00	138.00	34.50	405.00	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)
105	TURK - AR	Distribution		138.00	115.00	13.20	166.70	0	1
106	TURK - AR	Distribution		138.00	115.00	36.20	200.00	0	1
107	TURK - AR	Distribution		138.00	115.00	13.20	100.00	1	0
108	TWELFTH STREET (SW) - AR	Distribution		69.00	12.47	0.00	24.80	2	0
109	U.S. MOTORS - AR	Distribution		69.00	4.16	2.40	5.60	1	0
110	VAN ASCHE - AR	Distribution		12.47	0.00	0.00	0.00	0	0
111	VAN ASCHE - AR	Distribution		161.00	12.47	0.00	48.00	2	0
112	WALDRON - AR	Distribution		69.00	12.47	0.00	7.50	1	0
113	WALDRON - AR	Transmission		69.00	13.09	0.00	7.50	1	0
114	WEST BOONEVILLE - AR	Transmission		161.00	69.00	11.75	40.00	1	0
115	ARSENAL HILL - LA	Transmission		138.00	0.00	0.00	0.00	0	0
116	ARSENAL HILL - LA	Distribution		138.00	70.50	12.47	400.00	2	0
117	ARSENAL HILL - LA	Distribution		69.00	12.47	0.00	84.00	2	0
118	ARSENAL HILL - LA	Transmission		138.00	0.00	0.00	0.00	0	0
119	ARSENAL HILL - LA	Transmission		12.00	0.00	0.00	0.00	0	0
120	BAYOU PIERRE - LA	Transmission		69.00	13.20	0.00	7.00	1	0
121	BEAN - LA	Distribution		12.00	0.00	0.00	0.00	0	0
122	BEAN - LA	Transmission		138.00	12.47	0.00	40.00	1	0
123	BELCHER - LA	Transmission		69.00	12.47	0.00	6.25	1	0
124	BELLEVUE - LA	Distribution		69.00	12.47	0.00	12.50	1	0
125	BELLEVUE OIL FIELD - LA	Distribution		69.00	12.47	0.00	5.00	1	0
126	BELMONT (SEP) - LA	Distribution		69.00	13.20	0.00	14.00	1	0
127	BLANCHARD - LA	Distribution		69.00	11.95	0.00	15.00	2	0
128	BLANCHARD - LA	Distribution		69.00	13.09	0.00	15.00	1	0
129	BODCAU ROAD - LA	Distribution		138.00	12.47	0.00	40.00	2	0
130	BOSSIER CITY - LA	Distribution		69.00	12.47	0.00	70.00	2	0
131	BROADMOOR - LA	Transmission		69.00	12.50	0.00	20.00	1	0
132	BROADMOOR - LA	Transmission		69.00	13.09	0.00	25.00	1	0
133	BROADMOOR - LA	Transmission		12.00	0.00	0.00	0.00	0	0
134	BROOKS STREET (SW) - LA	Transmission		69.00	12.50	0.00	40.00	2	0
135	BROOKS STREET (SW) - LA	Transmission		12.00	0.00	0.00	0.00	0	0
136	BROWNLEE - LA	Transmission		69.00	34.50	0.00	53.00	4	0
137	BROWNLEE - LA	Transmission		69.00	34.50	0.00	53.00	4	0
138	BROWNLEE - LA	Transmission		69.00	12.47	0.00	25.00	2	0
139	CALUMET - LA	Transmission		69.00	12.47	0.00	6.25	1	0
140	CAMPTI - LA	Transmission		69.00	13.09	0.00	10.00	0	1
141	CANE RIVER (SEP) - LA	Distribution		115.00	13.20	0.00	53.00	2	0
142	CANE RIVER (SEP) - LA	Distribution		34.50	13.09	0.00	7.50	0	1
143	CANE RIVER (SEP) - LA	Distribution		34.50	13.09	0.00	7.50	0	1
144	CANE RIVER (SEP) - LA	Distribution		34.50	13.09	0.00	7.50	0	1
145	CANE RIVER (SEP) - LA	Distribution		34.50	13.09	0.00	7.50	0	1
146	CAPLIS - LA	Distribution		12.47	0.00	0.00	0.00	0	0
147	CAPLIS - LA	Transmission		138.00	36.20	0.00	30.00	1	0
148	CAPLIS - LA	Distribution		138.00	12.47	0.00	25.00	1	0
149	CARROLL (SEP) - LA	Distribution		34.50	13.20	0.00	3.50	1	0
150	CEDAR GROVE (SW) - LA	Transmission		138.00	0.00	0.00	0.00	0	0
151	CRESTON - LA	Transmission		34.50	13.20	0.00	7.00	1	0
152	DERRY - LA	Distribution		34.50	13.20	0.00	10.50	1	0
153	DOGWOOD - LA	Transmission		69.00	12.47	0.00	10.50	1	0
154	DOGWOOD - LA	Transmission		69.00	13.09	0.00	7.50	1	0
155	EDWARDS STREET - LA	Transmission		69.00	12.50	0.00	20.00	1	0
156	ELLERBE ROAD - LA	Transmission		12.00	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)
157	ELLERBE ROAD - LA	Transmission		69.00	12.47	0.00	56.00	2	0
158	FERN STREET - LA	Transmission		12.00	0.00	0.00	0.00	0	0
159	FINNEY - LA	Transmission		69.00	4.36	0.00	25.00	4	0
160	FLOURNOY - LA	Distribution		69.00	12.50	0.00	40.00	2	0
161	FLOURNOY - LA	Distribution		138.00	72.60	7.20	80.00	1	0
162	FORD - LA	Distribution		69.00	12.47	0.00	12.00	1	0
163	FORT HUMBUG - LA	Distribution		12.00	0.00	0.00	0.00	0	0
164	FORT HUMBUG - LA	Distribution		12.47	0.00	0.00	0.00	0	0
165	FORT HUMBUG - LA	Distribution		138.00	70.50	13.09	130.00	1	0
166	GAHAGAN - LA	Distribution		34.50	13.20	0.00	10.50	1	0
167	GENERAL MOTORS - LA	Transmission		138.00	13.80	0.00	90.00	2	0
168	GILLIAM - LA	Transmission		69.00	12.47	0.00	5.00	1	0
169	GRAND ECORE - LA	Transmission		34.50	13.20	0.00	14.00	1	0
170	GRAVEL POINT - LA	Transmission		69.00	26.40	0.00	14.00	1	0
171	HARDY STREET - LA	Transmission		69.00	12.47	0.00	26.50	2	0
172	HARTS ISLAND - LA	Transmission		138.00	34.50	0.00	100.00	2	0
173	HARTS ISLAND - LA	Distribution		34.50	0.00	0.00	0.00	0	0
174	HAUGHTON - LA	Distribution		138.00	12.47	0.00	10.50	1	0
175	HAUGHTON - LA	Distribution		138.00	13.09	0.00	25.00	1	0
176	HICKS - LA	Distribution		69.00	13.20	0.00	14.00	1	0
177	HORNBECK - LA	Distribution		69.00	24.90	0.00	28.00	1	0
178	HOSSTON - LA	Distribution		69.00	13.09	0.00	10.00	1	0
179	KINGSTON - LA	Distribution		69.00	24.90	0.00	28.00	1	0
180	KURTHWOOD - LA	Distribution		34.50	13.20	0.00	2.58	1	0
181	LAYFIELD 500KV - LA	Distribution		500.00	230.00	13.80	1000.00	4	0
182	LEASIDE WAY - LA	Distribution		138.00	69.00	0.00	130.00	1	0
183	LIEBERMAN - LA	Distribution		138.00	69.00	13.20	50.00	2	0
184	LIEBERMAN - LA	Distribution		138.00	69.00	13.00	50.00	1	0
185	LIEBERMAN 12KV - LA	Distribution		69.00	12.47	0.00	14.00	2	0
186	LINTON ROAD - LA	Distribution		138.00	13.09	0.00	40.00	2	0
187	LINWOOD (SW) - LA	Distribution		12.00	0.00	0.00	0.00	0	0
188	LINWOOD (SW) - LA	Distribution		138.00	12.47	0.00	66.00	2	0
189	LOGANSPORT - LA	Distribution		138.00	0.00	0.00	0.00	0	0
190	LOGANSPORT - LA	Distribution		138.00	69.00	13.80	33.60	1	0
191	LOGANSPORT - LA	Distribution		69.00	13.09	0.00	12.50	1	0
192	LOGANSPORT - LA	Distribution		69.00	12.47	0.00	7.00	1	0
193	LOGANSPORT - LA	Distribution		138.00	69.00	13.20	33.30	1	0
194	LONGWOOD (SW) - LA	Distribution		12.00	0.00	0.00	0.00	0	0
195	LONGWOOD (SW) - LA	Distribution		12.00	0.00	0.00	0.00	0	0
196	LONGWOOD (SW) - LA	Distribution		345.00	138.00	13.80	149.00	1	0
197	LONGWOOD (SW) - LA	Distribution		345.00	138.00	12.50	298.00	2	0
198	LUCAS - LA	Distribution		12.00	0.00	0.00	0.00	0	0
199	LUCAS - LA	Distribution		69.00	13.09	0.00	80.00	2	0
200	MANSFIELD - LA	Distribution		34.50	13.20	0.00	5.00	1	0
201	MANY - LA	Distribution		69.00	13.20	0.00	28.00	1	0
202	MARTHAVILLE - LA	Distribution		69.00	13.20	0.00	14.00	1	0
203	MARTIN (SW) - LA	Distribution		34.50	13.20	0.00	22.50	2	0
204	MARTIN (SW) - LA	Distribution		34.50	12.47	0.00	22.50	2	0
205	MCDADE - LA	Distribution		138.00	12.47	0.00	30.50	2	0
206	MCWILLIE STREET - LA	Distribution		12.00	0.00	0.00	0.00	0	0
207	MCWILLIE STREET - LA	Distribution		138.00	12.47	0.00	66.30	2	0
208	MIDWAY (SW) - LA	Distribution		69.00	12.47	0.00	94.00	4	0

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209	MINDEN ROAD - LA	Transmission		69.00	12.47	0.00	40.00	2	0
210	MINDEN ROAD - LA	Transmission		12.00	0.00	0.00	0.00	0	0
211	MOTT - LA	Distribution		69.00	24.90	0.00	14.00	1	0
212	MOTT - LA	Transmission		26.00	12.00	0.00	5.60	6	0
213	NEGREET - LA	Transmission		69.00	24.90	0.00	11.20	1	0
214	NOBLE (SEP) - LA	Distribution		69.00	26.40	0.00	25.00	0	1
215	NOBLE (SEP) - LA	Distribution		69.00	24.90	0.00	28.00	2	0
216	NORTH BENTON (NEW) - LA	Distribution		138.00	70.50	13.09	54.00	1	0
217	NORTH LEESVILLE - LA	Distribution		69.00	24.90	0.00	25.00	1	0
218	NORTH MARKET - LA	Distribution		69.00	12.50	0.00	40.00	2	0
219	OIL CITY - LA	Distribution		69.00	13.20	0.00	5.60	1	0
220	PIERREMONT - LA	Distribution		138.00	34.50	0.00	50.00	1	0
221	PIERREMONT - LA	Distribution		138.00	12.47	0.00	9.38	1	0
222	PIERREMONT - LA	Distribution		12.00	0.00	0.00	0.00	0	0
223	PINES ROAD - LA	Distribution		69.00	12.47	0.00	20.00	1	0
224	PINES ROAD - LA	Distribution		69.00	12.50	0.00	20.00	1	0
225	PLAIN DEALING - LA	Distribution		69.00	12.47	0.00	10.50	1	0
226	PLAIN DEALING - LA	Distribution		69.00	13.09	0.00	9.38	1	0
227	PORT ROBSON - LA	Distribution		138.00	12.47	0.00	25.00	1	0
228	POWELL STREET - LA	Distribution		12.00	0.00	0.00	0.00	0	0
229	POWELL STREET - LA	Distribution		138.00	12.47	0.00	66.00	2	0
230	POWHATAN (SEP) - LA	Transmission		34.50	13.20	0.00	3.13	1	0
231	PROVENCAL - LA	Transmission		115.00	13.20	0.00	56.00	2	0
232	RAINES - LA	Transmission		12.00	0.00	0.00	0.00	0	0
233	RED OAK (SEP) - LA	Distribution		34.50	13.20	0.00	7.00	1	0
234	RED POINT - LA	Distribution		138.00	72.60	13.20	42.00	1	0
235	RED POINT - LA	Distribution		138.00	0.00	0.00	0.00	0	0
236	RED POINT - LA	Distribution		138.00	13.09	0.00	25.00	1	0
237	RED POINT - LA	Transmission		138.00	66.00	13.80	50.00	1	0
238	ROBELINE - LA	Transmission		69.00	13.09	0.00	9.38	1	0
239	SHED ROAD - LA	Transmission		69.00	13.09	0.00	10.00	1	0
240	SHED ROAD - LA	Transmission		12.00	0.00	0.00	0.00	0	0
241	SHED ROAD - LA	Transmission		69.00	12.47	0.00	14.00	1	0
242	SOUTH SHREVEPORT - LA	Transmission		12.00	0.00	0.00	0.00	0	0
243	SOUTH SHREVEPORT - LA	Transmission		138.00	72.60	13.20	166.00	2	0
244	SOUTH SHREVEPORT - LA	Transmission		138.00	12.47	0.00	44.80	2	0
245	SOUTHWEST SHREVEPORT - LA	Distribution		34.50	0.00	0.00	0.00	0	0
246	SOUTHWEST SHREVEPORT - LA	Distribution		345.00	138.00	13.80	600.00	0	1
247	SOUTHWEST SHREVEPORT - LA	Distribution		345.00	138.00	34.50	810.00	2	0
248	SUMMER GROVE - LA	Distribution		69.00	12.47	7.20	7.00	1	0
249	SUMMER GROVE - LA	Distribution		69.00	12.47	0.00	7.00	1	0
250	SUMMER GROVE - LA	Distribution		12.00	0.00	0.00	0.00	0	0
251	SUPERIOR (SW) - LA	Distribution		69.00	12.47	0.00	20.88	2	0
252	TRICHEL STREET - LA	Distribution		138.00	13.09	0.00	40.00	1	0
253	TRICHEL STREET - LA	Distribution		138.00	12.47	0.00	42.00	1	0
254	TRICHEL STREET - LA	Distribution		12.00	0.00	0.00	0.00	0	0
255	VIVIAN - LA	Distribution		69.00	12.47	0.00	18.75	2	0
256	WALLACE LAKE - LA	Distribution		138.00	69.00	13.00	83.00	1	0
257	WATERWORKS (SW) - LA	Distribution		69.00	12.50	0.00	40.00	2	0
258	WATERWORKS (SW) - LA	Distribution		69.00	12.47	0.00	14.00	1	0
259	WESTERN ELECTRIC - LA	Distribution		138.00	34.50	0.00	144.00	2	0
260	WESTERN ELECTRIC - LA	Distribution		12.00	0.00	0.00	0.00	0	0

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261	WESTERN ELECTRIC - LA	Distribution		34.50	0.00	0.00	0.00	0	0
262	WESTERN ELECTRIC - LA	Distribution		138.00	12.47	0.00	40.00	2	0
263	WHITEHURST - LA	Transmission		138.00	34.50	0.00	121.70	2	0
264	WHITEHURST - LA	Transmission		12.00	0.00	0.00	0.00	0	0
265	WHITEHURST - LA	Transmission		138.00	12.47	0.00	20.00	1	0
266	AIR PRODUCTS (SW) - TX	Distribution		69.00	12.00	0.00	7.00	1	0
267	AIRLINE - TX	Distribution		69.00	12.47	0.00	20.00	1	0
268	AIRLINE - TX	Distribution		69.00	12.50	0.00	20.00	1	0
269	ALUMAX - TX	Distribution		138.00	13.80	0.00	12.00	1	0
270	ATLANTA - TX	Distribution		12.00	0.00	0.00	0.00	0	0
271	ATLANTA - TX	Distribution		69.00	12.47	0.00	66.00	2	0
272	BALDWIN - TX	Distribution		69.00	13.09	0.00	25.00	4	0
273	BALDWIN - TX	Distribution		69.00	12.00	0.00	5.00	1	0
274	BANN - TX	Distribution		138.00	72.60	12.00	852.00	8	0
275	BANN - TX	Distribution		138.00	72.60	13.80	133.00	1	0
276	BECKVILLE - TX	Distribution		69.00	13.09	0.00	6.25	1	0
277	BIG SANDY (SW) - TX	Distribution		69.00	13.09	0.00	9.38	1	0
278	BRYANS MILL - TX	Distribution		138.00	12.47	0.00	9.38	1	0
279	CAREY - TX	Distribution		69.00	7.20	0.00	1.50	3	0
280	CARTHAGE - TX	Distribution		12.00	0.00	0.00	0.00	0	0
281	CARTHAGE - TX	Distribution		69.00	12.50	0.00	40.00	2	0
282	CENTER - TX	Distribution		138.00	0.00	0.00	0.00	0	0
283	CENTER - TX	Transmission		138.00	12.47	0.00	84.00	2	0
284	CENTER - TX	Transmission		12.00	0.00	0.00	0.00	0	0
285	CHILDRESS AIRPORT PRISON - TX	Transmission		69.00	13.09	0.00	2.49	3	0
286	CHILDRESS AMOCO - TX	Transmission		69.00	4.16	2.40	7.50	1	0
287	CHILDRESS WEST (SEP) - TX	Distribution		0.00	0.00	0.00	0.00	0	0
288	CHILDRESS WEST (SEP) - TX	Distribution		7.62	0.00	0.00	0.00	0	0
289	CHILDRESS WEST (SEP) - TX	Distribution		138.00	69.00	12.47	50.00	1	0
290	CITY LAKE SUB - TX	Distribution		69.00	13.09	0.00	30.00	2	0
291	CLARENDON - TX	Transmission		69.00	7.56	0.00	6.90	3	0
292	CLARKSVILLE - TX	Transmission		12.00	0.00	0.00	0.00	0	0
293	CLARKSVILLE - TX	Transmission		69.00	12.50	0.00	20.00	1	0
294	CLARKSVILLE - TX	Transmission		69.00	12.47	0.00	20.00	1	0
295	COOKVILLE (SW) - TX	Transmission		69.00	12.47	0.00	4.66	1	0
296	CROCKETT - TX	Transmission		345.00	138.00	13.80	600.00	2	0
297	DAINGERFIELD - TX	Distribution		69.00	12.47	0.00	42.40	2	0
298	DEKALB - TX	Distribution		69.00	12.47	0.00	18.75	2	0
299	DIANA - TX	Distribution		345.00	138.00	13.80	750.00	3	0
300	ESTELLINE - TX	Distribution		69.00	13.09	0.00	2.49	3	0
301	EVENSIDE - TX	Distribution		69.00	12.50	0.00	40.00	2	0
302	EVENSIDE - TX	Distribution		12.00	0.00	0.00	0.00	0	0
303	FERNDALE LAKE - TX	Distribution		69.00	12.00	0.00	2.00	1	0
304	FRIARS SWITCH - TX	Distribution		138.00	12.47	0.00	28.00	2	0
305	GATES - TX	Distribution		69.00	12.47	0.00	12.00	1	0
306	GILMER - TX	Transmission		69.00	12.50	0.00	40.00	2	0
307	GRAND SALINE - TX	Transmission		12.00	0.00	0.00	0.00	0	0
308	GRAND SALINE - TX	Distribution		69.00	13.09	0.00	15.00	2	0
309	GREGGTON - TX	Distribution		69.00	12.50	0.00	40.00	2	0
310	GREGGTON - TX	Distribution		69.00	12.00	0.00	4.69	1	0
311	HALLSVILLE - TX	Distribution		138.00	13.09	0.00	95.00	5	0
312	HARRISON ROAD - TX	Distribution		138.00	34.50	0.00	133.00	2	0

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313	HAWKINS - TX	Distribution		69.00	12.47	0.00	25.00	2	0
314	HEDLEY - TX	Distribution		69.00	12.50	0.00	2.49	3	0
315	HOOKS - TX	Distribution		69.00	12.47	0.00	21.00	2	0
316	HOWELL - TX	Distribution		12.00	0.00	0.00	0.00	0	0
317	HOWELL - TX	Distribution		69.00	12.47	0.00	33.00	1	0
318	HUGHES SPRINGS - TX	Distribution		69.00	12.47	4.16	21.00	2	0
319	IPC 138KV - TX	Distribution		138.00	13.09	0.00	9.38	1	0
320	IPC 138KV - TX	Distribution		138.00	0.00	0.00	0.00	0	0
321	IPC-DOMINO - TX	Distribution		138.00	12.47	0.00	7.00	1	0
322	IPC-JEFFERSON - TX	Distribution		138.00	12.47	0.00	28.00	2	0
323	JEFFERSON - TX	Distribution		69.00	12.47	0.00	9.38	1	0
324	JERICHO - TX	Distribution		115.00	69.00	8.30	41.70	1	0
325	KILGORE - TX	Distribution		69.00	12.50	0.00	20.00	1	0
326	KILGORE - TX	Distribution		69.00	12.47	0.00	40.00	2	0
327	KILGORE - TX	Distribution		12.00	0.00	0.00	0.00	0	0
328	KINGS HIGHWAY - TX	Transmission		69.00	12.50	0.00	40.00	2	0
329	KNOX LEE - TX	Transmission		69.00	0.00	0.00	0.00	0	0
330	KNOX LEE - TX	Distribution		138.00	69.00	12.00	133.00	1	0
331	KNOX LEE - TX	Distribution		69.00	13.09	0.00	9.38	1	0
332	LAKE LAMOND - TX	Transmission		12.00	0.00	0.00	0.00	0	0
333	LAKE LAMOND - TX	Distribution		69.00	12.47	0.00	60.00	3	0
334	LAKE LAMOND - TX	Distribution		138.00	72.60	13.80	80.00	1	0
335	LAKE PAULINE (SEP) - TX	Distribution		138.00	69.00	14.40	62.50	1	0
336	LAKE PAULINE (SEP) - TX	Distribution		69.00	0.00	0.00	0.00	0	0
337	LETOURNEAU 69/12 - TX	Distribution		69.00	0.00	0.00	0.00	0	0
338	LETOURNEAU 69/12 - TX	Distribution		69.00	12.47	0.00	25.00	1	0
339	LEVERETTS CHAPEL - TX	Distribution		138.00	12.47	0.00	9.38	1	0
340	LIBERTY CITY - TX	Distribution		138.00	12.47	0.00	11.22	6	0
341	LINDEN - TX	Transmission		69.00	12.47	0.00	13.25	2	0
342	LONDON (SW) - TX	Transmission		138.00	12.47	0.00	28.00	2	0
343	LONE STAR SHELL ORDNANCE - TX	Transmission		69.00	12.47	0.00	10.00	2	0
344	LONE STAR SOUTH - TX	Distribution		138.00	69.00	12.47	133.00	1	0
345	LONGVIEW - TX	Distribution		69.00	13.09	0.00	25.00	1	0
346	LONGVIEW - TX	Distribution		69.00	12.50	0.00	20.00	1	0
347	LONGVIEW HEIGHTS - TX	Distribution		138.00	12.47	0.00	40.00	2	0
348	LONGVIEW HEIGHTS - TX	Distribution		12.00	0.00	0.00	0.00	0	0
349	LOUISIANA PACIFIC - TX	Distribution		69.00	12.47	0.00	24.00	2	0
350	MARSHALL 138KV - TX	Distribution		138.00	69.00	13.00	133.00	1	0
351	MARSHALL 138KV - TX	Transmission		138.00	69.00	7.20	133.00	1	0
352	MARSHALL 69KV - TX	Distribution		69.00	11.95	0.00	7.50	1	0
353	MARSHALL 69KV - TX	Distribution		12.00	0.00	0.00	0.00	0	0
354	MARSHALL 69KV - TX	Transmission		69.00	13.09	0.00	48.00	4	0
355	MEMPHIS - TX	Transmission		69.00	13.00	0.00	12.60	3	0
356	MEMPHIS - TX	Distribution		69.00	0.00	0.00	0.00	0	0
357	MEMPHIS NW - TX	Distribution		69.00	0.00	0.00	0.00	0	0
358	MID-VALLEY - TX	Distribution		69.00	2.40	0.00	9.38	1	0
359	MID-VALLEY LONGVIEW - TX	Distribution		69.00	2.40	0.00	7.00	1	0
360	MINEOLA - TX	Distribution		69.00	0.00	0.00	0.00	0	0
361	MINEOLA - TX	Distribution		69.00	13.09	0.00	45.00	2	0
362	MINEOLA - TX	Distribution		0.00	0.00	0.00	0.00	0	0
363	MONROE CORNERS - TX	Distribution		69.00	12.47	0.00	7.00	1	0
364	MOUNT PLEASANT - TX	Distribution		69.00	12.47	0.00	11.20	1	0

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365	MOUNT PLEASANT - TX	Distribution		69.00	13.09	0.00	22.40	2	0
366	MOUNT VERNON (SW) - TX	Distribution		69.00	12.47	0.00	28.00	2	0
367	MOUNT VERNON (SW) - TX	Distribution		12.00	0.00	0.00	0.00	0	0
368	NAPLES - TX	Distribution		69.00	12.47	0.00	11.25	2	0
369	NASH - TX	Distribution		138.00	12.47	0.00	50.00	2	0
370	NETTLETON - TX	Distribution		69.00	2.40	0.00	2.50	1	0
371	NEW BOSTON - TX	Distribution		12.00	0.00	0.00	0.00	0	0
372	NEW BOSTON - TX	Distribution		69.00	12.47	0.00	20.00	1	0
373	NEW BOSTON - TX	Distribution		69.00	12.50	0.00	20.00	1	0
374	NEW GLADEWATER - TX	Distribution		138.00	12.47	0.00	33.30	1	0
375	NEW GLADEWATER - TX	Transmission		12.00	0.00	0.00	0.00	0	0
376	NEW HOPE (SW) - TX	Transmission		69.00	12.47	0.00	18.75	2	0
377	NORTH LANEVILLE - TX	Distribution		69.00	34.50	0.00	5.00	1	0
378	NORTH MARSHALL - TX	Distribution		69.00	12.47	0.00	14.00	1	0
379	NORTH MARSHALL - TX	Distribution		12.00	0.00	0.00	0.00	0	0
380	NORTH MINEOLA - TX	Transmission		69.00	0.00	0.00	0.00	0	0
381	NORTH MINEOLA - TX	Distribution		138.00	0.00	0.00	0.00	0	0
382	NORTH MINEOLA - TX	Distribution		138.00	0.00	0.00	0.00	0	0
383	NORTH MINEOLA - TX	Distribution		138.00	72.60	7.20	80.00	1	0
384	NORTH MINEOLA - TX	Distribution		69.00	0.00	0.00	0.00	0	0
385	NORTH MINEOLA - TX	Transmission		69.00	12.47	0.00	9.38	1	0
386	NORTH NEW BOSTON - TX	Transmission		138.00	72.60	13.20	83.00	1	0
387	NORTHWEST HENDERSON - TX	Transmission		138.00	69.00	13.20	166.00	2	0
388	NORTHWEST TEXARKANA - TX	Distribution		345.00	138.00	13.80	960.00	2	0
389	NORTHWEST TEXARKANA - TX	Distribution		12.00	0.00	0.00	0.00	0	0
390	OVERTON - TX	Distribution		138.00	72.60	13.20	84.00	2	0
391	OVERTON - TX	Transmission		138.00	0.00	0.00	0.00	0	0
392	OVERTON - TX	Transmission		138.00	0.00	0.00	0.00	0	0
393	PERDUE - TX	Distribution		138.00	70.50	13.09	130.00	1	0
394	PERDUE - TX	Distribution		138.00	0.00	0.00	0.00	0	0
395	PETTY - TX	Distribution		69.00	13.09	0.00	7.50	1	0
396	PETTY - TX	Distribution		138.00	70.50	13.09	78.00	1	0
397	PETTY - TX	Distribution		138.00	69.00	13.80	133.00	1	0
398	PILGRIMS PRIDE - TX	Distribution		69.00	12.47	0.00	24.00	2	0
399	PIRKEY - TX	Transmission		345.00	138.00	34.50	500.00	1	0
400	PIRKEY - TX	Distribution		345.00	138.00	13.80	360.00	1	0
401	PITTSBURG (SW) - TX	Transmission		138.00	72.60	7.20	133.00	1	0
402	PITTSBURG (SW) - TX	Distribution		69.00	12.50	0.00	40.00	2	0
403	PITTSBURG STEEL - TX	Distribution		69.00	12.00	0.00	6.25	1	0
404	PLILER ROAD - TX	Distribution		138.00	34.50	0.00	100.00	2	0
405	POYNTER - TX	Distribution		12.00	0.00	0.00	0.00	0	0
406	POYNTER - TX	Distribution		69.00	12.47	0.00	26.50	2	0
407	RED RIVER ARSENAL - TX	Distribution		69.00	12.47	0.00	12.50	1	0
408	RICHMOND ROAD - TX	Transmission		69.00	12.47	0.00	20.00	1	0
409	ROCK HILL - TX	Transmission		138.00	70.50	13.09	180.00	2	0
410	ROSBOROUGH - TX	Distribution		69.00	12.47	0.00	2.00	1	0
411	SABINE - TX	Distribution		12.00	0.00	0.00	0.00	0	0
412	SABINE - TX	Distribution		69.00	12.47	0.00	20.00	1	0
413	SCOTTSVILLE (SW) - TX	Distribution		138.00	12.47	0.00	24.00	2	0
414	SERVICE PIPELINE - TX	Distribution		69.00	2.40	0.00	3.13	1	0
415	SHAMROCK (SEP) - TX	Transmission		69.00	0.00	0.00	0.00	0	0
416	SHAMROCK (SEP) - TX	Distribution		69.00	13.09	0.00	11.10	3	0

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)			
417	SHAMROCK (SEP) - TX	Distribution		138.00	69.00	6.10	62.50	1	0
418	SHAMROCK (SEP) - TX	Distribution		115.00	69.00	14.40	62.50	1	0
419	SOHIO - TX	Distribution		69.00	2.40	0.00	2.00	1	0
420	SOUTHEAST LONGVIEW - TX	Distribution		69.00	12.50	0.00	42.00	1	0
421	SOUTHEAST LONGVIEW - TX	Distribution		69.00	12.47	0.00	41.67	1	0
422	SOUTHEAST MARSHALL - TX	Distribution		138.00	12.47	0.00	55.40	2	0
423	SPRINGHILL - TX	Distribution		138.00	12.47	0.00	22.40	1	0
424	TATUM - TX	Distribution		138.00	12.47	0.00	9.38	1	0
425	TAYLOR STREET - TX	Distribution		12.00	0.00	0.00	0.00	0	0
426	TAYLOR STREET - TX	Distribution		69.00	12.47	0.00	66.00	2	0
427	TENAHA - TX	Distribution		138.00	0.00	0.00	0.00	0	0
428	TENAHA - TX	Distribution		138.00	12.47	0.00	9.38	1	0
429	TEXARKANA OPERATIONS CENTER - TX	Distribution		12.00	0.00	0.00	0.00	0	0
430	TEXARKANA OPERATIONS CENTER - TX	Distribution		69.00	12.50	0.00	20.00	1	0
431	TEXAS EASTERN - TX	Distribution		69.00	2.30	0.00	7.50	2	0
432	THIRTY-NINTH STREET - TX	Distribution		12.00	0.00	0.00	0.00	0	0
433	THIRTY-NINTH STREET - TX	Distribution		69.00	12.50	0.00	20.00	1	0
434	THIRTY-NINTH STREET - TX	Distribution		69.00	12.47	0.00	33.00	1	0
435	TURNERTOWN - TX	Distribution		69.00	12.47	0.00	9.38	1	0
436	TURNERTOWN - TX	Transmission		69.00	13.09	0.00	9.38	1	0
437	WASKOM - TX	Transmission		69.00	13.09	0.00	11.20	1	0
438	WASKOM - TX	Transmission		69.00	13.09	0.00	12.00	1	0
439	WELLINGTON - TX	Transmission		138.00	7.56	0.00	14.01	3	0
440	WELSH HVDC CONVERTER - TX	Transmission		345.00	69.00	69.00	246.00	1	0
441	WELSH HVDC CONVERTER - TX	Transmission		345.00	69.00	69.00	539.00	2	0
442	WELSH HVDC CONVERTER - TX	Transmission		345.00	69.00	0.00	296.00	1	0
443	WELSH HVDC CONVERTER - TX	Transmission		345.00	0.00	0.00	0.00	0	0
444	WELSH HVDC CONVERTER - TX	Transmission		345.00	69.80	69.80	293.00	1	0
445	WELSH HVDC CONVERTER - TX	Transmission		345.00	69.00	69.80	539.00	2	0
446	WELSH HVDC CONVERTER - TX	Transmission		345.00	69.80	69.00	539.00	2	0
447	WELSH HVDC CONVERTER - TX	Transmission		345.00	69.80	69.80	1049.00	4	0
448	WEST ATLANTA - TX	Transmission		138.00	70.50	13.09	54.00	1	0
449	WEST MOUNT PLEASANT - TX	Transmission		69.00	12.47	0.00	10.00	1	0
450	WEST MOUNT PLEASANT - TX	Distribution		12.00	0.00	0.00	0.00	0	0
451	WESTWOOD - TX	Transmission		69.00	13.09	0.00	9.38	1	0
452	WHITNEY - TX	Transmission		69.00	12.47	0.00	120.00	6	0
453	WHITNEY - TX	Transmission		69.00	12.47	0.00	80.00	4	0
454	WHITNEY - TX	Transmission		138.00	70.50	13.09	208.00	2	0
455	WHITNEY - TX	Distribution		12.00	0.00	0.00	0.00	0	0
456	WILKES - TX	Distribution		13.80	0.00	0.00	0.00	0	0
457	WILKES - TX	Distribution		345.00	138.00	13.80	450.00	1	0
458	WINFIELD - TX	Distribution		69.00	12.47	0.00	9.37	2	0
459	WINNSBORO - TX	Distribution		69.00	12.50	0.00	20.00	1	0
460	WINNSBORO - TX	Distribution		69.00	12.00	0.00	20.00	1	0
461	WINNSBORO - TX	Distribution		138.00	70.50	12.47	130.00	1	0
462	WINNSBORO - TX	Transmission		138.00	0.00	0.00	0.00	0	0
463	WOODLAWN (SW) - TX	Distribution		69.00	12.47	0.00	6.25	1	0
464	TotalTransmissionSubstationMember								
465	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	STATCAP	1	6.00
5		0	0.00
6		0	0.00
7		0	0.00
8		0	0.00
9		0	0.00
10	STATCAP	1	6.00
11		0	0.00
12	STATCAP	2	32.40
13	XSLR - 0.4mH / 480A	3	0.00
14		0	0.00
15		0	0.00
16		0	0.00
17		0	0.00
18	STATCAP	1	3.20
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	STATCAP	1	43.20
26		0	0.00
27	Air Core Reactor	4	0.00
28		0	0.00
29	STATCAP	1	43.20
30		0	0.00
31	STATCAP	2	12.45
32		0	0.00
33		0	0.00
34		0	0.00
35		0	0.00
36		0	0.00
37		0	0.00
38		0	0.00
39		0	0.00
40		0	0.00
41		0	0.00
42		0	0.00
43	STATCAP	1	6.00
44		0	0.00
45		0	0.00
46	STATCAP	1	5.70
47	STATCAP	1	6.00
48		0	0.00
49		0	0.00
50	K06766-E060 34.5kV 400A 0.038 Ohm Air-Core Reactor	3	0.00
51		0	0.00
52	STATCAP	1	6.60
53		0	0.00

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	STATCAP	1	6.00
56	STATCAP	1	21.60
57		0	0.00
58		0	0.00
59		0	0.00
60	STATCAP	1	21.60
61		0	0.00
62	STATCAP	1	6.00
63		0	0.00
64		0	0.00
65		0	0.00
66		0	0.00
67		0	0.00
68	STATCAP	1	6.30
69	STATCAP	1	57.60
70		0	0.00
71		0	0.00
72		0	0.00
73		0	0.00
74		0	0.00
75		0	0.00
76		0	0.00
77		0	0.00
78	STATCAP	1	6.00
79		0	0.00
80		0	0.00
81	STATCAP	1	21.60
82		0	0.00
83		0	0.00
84		0	0.00
85	STATCAP	1	6.00
86		0	0.00
87	STATCAP	1	54.00
88	STATCAP	1	43.20
89		0	0.00
90	STATCAP	1	6.00
91		0	0.00
92		0	0.00
93		0	0.00
94		0	0.00
95		0	0.00
96	STATCAP	1	0.00
97		0	0.00
98		0	0.00
99		0	0.00
100		0	0.00
101	STATCAP	1	59.40
102		0	0.00
103	Air Core Reactor	3	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		0	0.00
108		0	0.00
109		0	0.00
110	STATCAP	1	7.20
111		0	0.00
112		0	0.00
113		0	0.00
114		0	0.00
115	Air Core Reactor	3	0.00
116		0	0.00
117		0	0.00
118	STATCAP	1	43.20
119	STATCAP	1	6.00
120		0	0.00
121	STATCAP	1	7.20
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		0	0.00
132		0	0.00
133	STATCAP	1	6.00
134		0	0.00
135	STATCAP	1	3,600.00
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		0	0.00
145		0	0.00
146	STATCAP	1	7.20
147		0	0.00
148		0	0.00
149		0	0.00
150	STATCAP	1	57.60
151		0	0.00
152		0	0.00
153		0	0.00
154		0	0.00
155		0	0.00
156	STATCAP	1	6.00
157		0	0.00
158	STATCAP	1	6.00
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	STATCAP	1	6.00
164	STATCAP	1	6.00
165		0	0.00
166		0	0.00
167		0	0.00
168		0	0.00
169		0	0.00
170		0	0.00
171		0	0.00
172		0	0.00
173	STATCAP	2	18.00
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		0	0.00
182		0	0.00
183		0	0.00
184		0	0.00
185		0	0.00
186		0	0.00
187	STATCAP	1	6.00
188		0	0.00
189	STATCAP	1	28.80
190		0	0.00
191		0	0.00
192		0	0.00
193		0	0.00
194	REACTOR	1	25.00
195	REACTOR	1	25.00
196		0	0.00
197		0	0.00
198	STATCAP	1	4.50
199		0	0.00
200		0	0.00
201		0	0.00
202		0	0.00
203		0	0.00
204		0	0.00
205		0	0.00
206	STATCAP	1	3.00
207		0	0.00
208		0	0.00
209		0	0.00
210	STATCAP	1	5.85
211		0	0.00
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		0	0.00
215		0	0.00
216		0	0.00
217		0	0.00
218		0	0.00
219		0	0.00
220		0	0.00
221		0	0.00
222	STATCAP	1	3.00
223		0	0.00
224		0	0.00
225		0	0.00
226		0	0.00
227		0	0.00
228	STATCAP	1	3.60
229		0	0.00
230		0	0.00
231		0	0.00
232	STATCAP	1	6.00
233		0	0.00
234		0	0.00
235	STATCAP	1	43.20
236		0	0.00
237		0	0.00
238		0	0.00
239		0	0.00
240	STATCAP	1	6.00
241		0	0.00
242	STATCAP	1	6.00
243		0	0.00
244		0	0.00
245	Air Core Reactor	9	75.03
246		0	0.00
247		0	0.00
248		0	0.00
249		0	0.00
250	STATCAP	1	4.80
251		0	0.00
252		0	0.00
253		0	0.00
254	STATCAP	1	4.20
255		0	0.00
256		0	0.00
257		0	0.00
258		0	0.00
259		0	0.00
260	STATCAP	1	6.00
261	STATCAP	2	18.00
262		0	0.00
263		0	0.00
264	STATCAP	1	6.00
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		0	0.00
268		0	0.00
269		0	0.00
270	STATCAP	1	6.00
271		0	0.00
272		0	0.00
273		0	0.00
274		0	0.00
275		0	0.00
276		0	0.00
277		0	0.00
278		0	0.00
279		0	0.00
280	STATCAP	2	12.30
281		0	0.00
282	STATCAP	1	31.20
283		0	0.00
284	STATCAP	1	6.00
285		0	0.00
286		0	0.00
287	STATCAP	1	6.60
288	Air Core Reactor	3	19.97
289		0	0.00
290		0	0.00
291		0	0.00
292	STATCAP	2	6.80
293		0	0.00
294		0	0.00
295		0	0.00
296		0	0.00
297		0	0.00
298		0	0.00
299		0	0.00
300		0	0.00
301		0	0.00
302	STATCAP	1	6.00
303		0	0.00
304		0	0.00
305		0	0.00
306		0	0.00
307	STATCAP	1	6,000.00
308		0	0.00
309		0	0.00
310		0	0.00
311		0	0.00
312		0	0.00
313		0	0.00
314		0	0.00
315		0	0.00
316	STATCAP	1	6.00
317		0	0.00
318		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
319		0	0.00
320	STATCAP	2	28.80
321		0	0.00
322		0	0.00
323		0	0.00
324		0	0.00
325		0	0.00
326		0	0.00
327	STATCAP	1	4.50
328		0	0.00
329	STATCAP	1	21.60
330		0	0.00
331		0	0.00
332	STATCAP	2	12.00
333		0	0.00
334		0	0.00
335		0	0.00
336	STATCAP	1	9.60
337	STATCAP	1	16.20
338		0	0.00
339		0	0.00
340		0	0.00
341		0	0.00
342		0	0.00
343		0	0.00
344		0	0.00
345		0	0.00
346		0	0.00
347		0	0.00
348	STATCAP	1	6.00
349		0	0.00
350		0	0.00
351		0	0.00
352		0	0.00
353	STATCAP	1	3.60
354		0	0.00
355		0	0.00
356	STATCAP	1	3.60
357	STATCAP	1	2.40
358		0	0.00
359		0	0.00
360	STATCAP	1	21.60
361		0	0.00
362	STATCAP	1	21.60
363		0	0.00
364		0	0.00
365		0	0.00
366		0	0.00
367	STATCAP	2	0.00
368		0	0.00
369		0	0.00
370		0	0.00
371	STATCAP	1	6.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
372		0	0.00
373		0	0.00
374		0	0.00
375	STATCAP	1	6.00
376		0	0.00
377		0	0.00
378		0	0.00
379	STATCAP	1	6.00
380	XSLR - 0.4mH / 480A	3	0.00
381	STATCAP	1	0.00
382	XSLR - 0.6mH / 480A	3	0.00
383		0	0.00
384	STATCAP	1	0.00
385		0	0.00
386		0	0.00
387		0	0.00
388		0	0.00
389	REACTOR	1	25.00
390		0	0.00
391	XSLR - 0.6mH / 480A	3	7.24
392	STATCAP	1	0.00
393		0	0.00
394	STATCAP	1	86.40
395		0	0.00
396		0	0.00
397		0	0.00
398		0	0.00
399		0	0.00
400		0	0.00
401		0	0.00
402		0	0.00
403		0	0.00
404		0	0.00
405	STATCAP	1	6.00
406		0	0.00
407		0	0.00
408		0	0.00
409		0	0.00
410		0	0.00
411	STATCAP	1	3.60
412		0	0.00
413		0	0.00
414		0	0.00
415	STATCAP	1	7.20
416		0	0.00
417		0	0.00
418		0	0.00
419		0	0.00
420		0	0.00
421		0	0.00
422		0	0.00
423		0	0.00
424		0	0.00

Line No.	Conversion Apparatus and Special Equipment		
	Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
425	STATCAP	1	6.00
426		0	0.00
427	STATCAP	1	31.20
428		0	0.00
429	STATCAP	1	6.00
430		0	0.00
431		0	0.00
432	STATCAP	1	5.85
433		0	0.00
434		0	0.00
435		0	0.00
436		0	0.00
437		0	0.00
438		0	0.00
439		0	0.00
440		0	0.00
441		0	0.00
442		0	0.00
443	STATCAP	1	100.00
444		0	0.00
445		0	0.00
446		0	0.00
447		0	0.00
448		0	0.00
449		0	0.00
450	STATCAP	1	6.00
451		0	0.00
452		0	0.00
453		0	0.00
454		0	0.00
455	STATCAP	1	6.00
456	K06766-E110 13.8kV 1046A 7.615 Ohm Air-Core Reacto	6	49.98
457		0	0.00
458		0	0.00
459		0	0.00
460		0	0.00
461		0	0.00
462	STATCAP	1	57.60
463		0	0.00
464			11,216.87
465			11,216.87

Name of Respondent: SWEPCO	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	[(a)] AEPSC	935	4,031,691
3	Factored Customer A/R Bad Debts	AEP Credit, Inc.	426.5	9,399,286
4	Treasury & Risk	AEPSC	920, 923	3,160,382
5	Administrative and General Expenses - Operation	AEPSC	920, 921, 922, 923, 925, 926, 928, 930.1, 930.2, 931	3,747,513
6	Factored Customer A/R Expense	AEP Credit, Inc.	426.5	11,773,974
7	Services for Jointly Owned Facility - North Central Wind	PSO	107, 108, 186, 408.1, 421, 426.1, 426.3, 426.4, 426.5, 431, 500, 501, 502, 506, 510, 546, 548, 549, 550, 553, 556, 557, 560, 561.2, 561.5, 563, 565, 566, 568, 569, 569.2, 570, 571, 573, 580, 587, 588, 920, 921, 922, 923, 924. 925, 926, 928, 930.1, 930.2, 931, 935	42,979,559
8	Audit Services	AEPSC	920, 923	801,552
9	Federal Affairs	AEPSC	920, 923	552,326
10	Central Machine Shop	APCo	107, 108, 500, 512, 513	541,407
11	Fuel & Storeroom Services	AEPSC	151, 152, 163, 163.1	7,500,834
12	Civil & Political Activities and Other Svcs	AEPSC	426.1, 426.33, 426.4, 426.5	583,702
13	Human Resources	AEPSC	920, 923	4,055,053
14	Construction Services	AEP Texas	107, 108	2,655,066
15	Information Technology	AEPSC	920, 923	7,315,360
16	Construction Services	AEPSC	107, 108	84,893,898
17	Infrastructure Ops & Support	AEPSC	920, 923	1,051,071
18	Construction Services	APCo	107, 108	377,233
19	Legal GC/Administration	AEPSC	920, 923	3,747,273
20	Construction Services	I&M	107, 108	565,045
21	Materials and Supplies	AEP Texas	107, 108, 184, 570, 571, 583, 592, 593, 594, 596, 935	1,240,775
22	Construction Services	OPCo	107, 108	679,184
23	Materials and Supplies	OPCo	107, 184, 560, 570, 592	1,333,814
24	Construction Services	PSO	107, 108	353,217
25	Materials and Supplies	PSO	107, 163, 502, 512, 513, 570, 571, 592	1,111,584
26	Corp Safety & Health	AEPSC	920, 923	1,878,442
27	Non-power Goods or Services Provided for Affiliate			
28	Other Power Supply Expenses	AEPSC	556, 557	3,659,935
29	Corporate Accounting	AEPSC	920, 923	2,039,915
30	Physical & Cyber Security	AEPSC	920, 923	730,867
31	Corporate Planning & Budgeting	AEPSC	920, 923	1,529,383
32	Rail Car Lease	I&M	186	1,207,683
33	Customer Accounts Expenses	AEPSC	901, 902, 903, 904, 905	14,157,755
34	Rail Car Maintenance	AEGCo	151	2,785,679
35	Distribution Expenses - Maintenance	AEP Texas	592, 593, 594, 595, 597	1,312,863
36	Research and Other Services	AEPSC	183, 184, 186, 188	4,175,481
37	Distribution Expenses - Maintenance	AEPSC	590, 591, 592, 593, 594, 595, 597, 598	388,441
38	Steam Power Generation - Maintenance	AEPSC	510, 511, 512, 513, 514	1,731,907

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)
39	Distribution Expenses - Maintenance	APCo	593	839,204
40	Steam Power Generation - Operation	AEPSC	500, 501, 502, 506, 508	12,509,790
41	Distribution Expenses - Maintenance	I&M	592, 593, 594, 596, 597	980,984
42	Distribution Expenses - Maintenance	KPCo	593, 594	294,825
43	Distribution Expenses - Maintenance	OPCo	593, 594, 595, 596, 597	1,685,989
44	Distribution Expenses - Operation	AEPSC	580, 581, 582, 583, 584, 586, 587, 588	3,552,929
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Administrative and General Expenses - Operation	DHLC	920, 921	339,791
22	Tax Services	AEPSC	920, 923	889,209
23	Building and Property Leases	AEPSC	454	1,480,609
24	Rail Car Maintenance Facility	Cook Coal Terminal	1,510	5,450,881
25	Central Maintenance Facility	PSO	107, 108, 512, 513	887,196
26	Non-power Goods or Services Provided for Affiliate			
27	Construction Services	AEP Texas	107, 108	926,577
28	Current and Accrued Liabilities	PSO	232	975,000
29	Distribution Expenses - Maintenance	AEP Texas	593, 594, 595, 596	326,448
30	HVDC East Transmission Tie	AEP Texas	186, 456, 561.3, 562, 570, 922, 924, 925	770,456
31	Materials and Supplies	AEPSC	154	487,929
32	Materials and Supplies	OHTCo	154	299,698
33	Materials and Supplies	PSO	154	299,014
34	Rail Car Lease	I&M	151	723,432
35	Rail Car Lease	PSO	151	420,463
36	Fleet and Vehicle Charges	AEP Texas	See Foot Note	74,748
42				
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Name of Respondent: SWEPCO	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: NameOfAssociatedAffiliatedCompany

Affiliated Companies shown in Column (B):

AEP Credit, Inc. - AEP Credit, Inc.
AEPSC - American Electric Power Service Corporation
AEP Texas - AEP Texas, Inc.
APCo - Appalachian Power Company
DHLC - Dolet Hills Lignite Company
I&M - Indiana Michigan Power Company
OPCo - Ohio Power Company
PSO - Public Service Company of Oklahoma
KPCo - Kentucky Power Company
OHTCo - Ohio Transmission Company

AEPSC Allocations

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.

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FLEET Allocations (Various)

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.